Memorandum Florida Department of Environmental Protection

To: Trina Vielhauer, Bureau of Air Regulation

Through: Al Linero, Special Projects Section aal

From: David Read, Special Projects Section DLR

Date: December 9, 2009

Subject: Revised Draft Air Permit No. 0470016-001-AC
ADAGE Hamilton, LLC, 55.5 MW Woody Biomass Power Plant

Attached for your review is a Revised Draft Air Construction Permit package for the new greenfield ADAGE Hamilton, LLC woody biomass power plant, which will be located in Hamilton County at the intersection of State Road 6 and County Road 146, immediately west of Interstate Highway 75 and approximately 7.5 miles west of Jasper, Florida.

The Revised package will be issued pursuant to the Settlement Stipulation executed by the Department and ADAGE on December 8, 2009 resolving matters related to the earlier Draft Permit package.

The attached Technical Evaluation and Preliminary Determination document provides a detailed description of the project and the rationale for permit issuance.

This project is not subject to the rules for the Prevention of Significant Deterioration. ADAGE Hamilton, LLC request for an extension of time to file an extension expires on December 23, 2009. I recommend your approval of the attached draft permit package.

Attachments

TLV/aal/dlr

Florida Department of Environmental Protection

Bob Martinez Center
2600 Blairstone Road
Tallahassee, Florida 32399-2400

Charlie Crist
Governor
Jeff Kottkamp
Lt. Governor
Michael W. Sole
Secretary

Mr. Francis Reed Wills, President
ADAGE Hamilton, LLC
225 Wilmington West Chester Pike
Suite 302
Chadds Ford, Pennsylvania 19317

Re: Revised Draft Air Permit No. 0470016-001-AC
ADAGE Hamilton, LLC
55.5 MW Woody Biomass Power Plant

Dear Mr. Wills:

On May 20, 2009, you submitted an application for an air construction permit subject to the preconstruction review requirements of Rule 62-212.300, Florida Administrative Code.

The purpose of the project is to construct a 55.5 megawatt (MW) power plant that will be fueled by woody biomass. This work will be conducted at the new ADAGE woody biomass power plant that will be located in Hamilton County, at the intersection of State Road 6 and County Road 146, immediately west of Interstate Highway 75 and approximately 7.5 miles west of Jasper, Florida.

The original Draft Permit and associated documents that were transmitted by the cover letter dated October 8, 2009 are hereby withdrawn and replaced by those enclosed herewith.

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

The Public Notice of Intent to Issue a Revised 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 the Project Engineer, David Read at 850/414-7268.

Sincerely,

Trina L. Vielhauer 12/10/09

Trina L. Vielhauer, Chief (Date)
Bureau of Air Regulation

Enclosures

TLV/aal/dlr

WRITTEN NOTICE OF INTENT TO ISSUE A REVISED AIR PERMIT

In the Matter of an
Application for Air Permit by:

ADAGE Hamilton, LLC
225 Wilmington West Chester Pike, Suite 302
Chadds Ford, Pennsylvania 19317

Authorized Representative: Mr. Francis Reed Wills, President

Draft Permit No. 0470016-001-AC
ADAGE Biomass Power Plant
55.5 MW Bubbling Fluidized Bed Boiler

Hamilton County, Florida

Facility Location: ADAGE Hamilton, LLC proposes to construct a new power plant fueled by woody biomass that will be located in Hamilton County, at the intersection of State Road 6 and County Road 146, immediately west of Interstate Highway 75 and approximately 7.5 miles west of Jasper, Florida.

Project: The project is the construction of a 55.5 megawatt (MW, net) electric power plant utilizing a bubbling fluidized bed boiler, fueled 100 tons per hour (TPH) of clean woody biomass. The project is subject to the preconstruction review requirements of Rule 62-212.300, Florida Administrative Code (F.A.C.). 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.

The previous written notice and accompanying documents transmitted on October 8, 2009 are hereby withdrawn and replaced with the present revised notice and accompanying documents.

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, 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 32301 and the mailing address is 2600 Blair Stone Road, MS #5505, Tallahassee, Florida 32399-2400. The Bureau of Air Regulation's phone number is 850/488-0114.

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 Revised 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 and phone number listed above.

Notice of Intent to Issue Air Permit: The Permitting Authority gives notice of its intent to issue a revised 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 applicable 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 revised Final Permit in accordance with the conditions of the proposed Revised 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 a Revised 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 the address or phone number listed above. 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 Revised 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 this 14-day period. If timely received comments result in a significant change to the Revised Draft Permit, the Permitting Authority shall revise the Revised 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 (Telephone: 850/245-2241; Fax: 850/245-2303). 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 a Revised 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 Revised Public Notice or within fourteen 14 days of receipt of this Written Notice of Intent to Issue a Revised 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; (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 a Revised 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.

Trina L. Vielhauer

Trina Vielhauer, Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Written Notice of Intent to Issue a Revised Air Permit package (including the Written Notice of Intent to Issue a Revised Air Permit, the Public Notice of Intent to Issue a Revised Air Permit, the Technical Evaluation and Preliminary Determination and the Revised Draft 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 12/10/09 to the persons listed below.

Francis Reed Wills, ADAGE: reed.wills@duke-energy.com
David Cibik, P.E., Malcolm Pirnie: dcibik@pirnie.com
Christopher Kirts, P.E., DEP Northwest District Office: christopher.kirts@dep.state.fl.us
Kathleen Forney, EPA Region 4: forney.kathleen@epamail.epa.gov
Heather Abrams, EPA Region 4: abrams.heather@epa.gov
Betty Johnson: bettyjohnson@shareinet.net
David Wiles: rprtcard@bellsouth.net
Joy Towles Ezell: hopeforcleanwater@yahoo.com
Danny Johnson, Hamilton County Coordinator: hamiltoncounty@alltel.net
Ron Stewart, Florida Pulp and Paper Association: rstewart@fppaea.org
Vickie Gibson, DEP BAR Reading File: victoria.gibson@dep.state.fl.us

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to Section 120.52(7), Florida Statutes, with the designated agency clerk, receipt of which is hereby acknowledged.

(Clerk) 12/10/09 (Date)

PUBLIC NOTICE OF INTENT TO ISSUE AIR PERMIT

Florida Department of Environmental Protection
Division of Air Resource Management, Bureau of Air Regulation

Draft Air Permit No. 0470016-001-AC
ADAGE Hamilton LLC, Woody Biomass Power Plant
Hamilton County, Florida

Applicant: The applicant for this project is ADAGE Hamilton LLC. The applicant's authorized representative and mailing address is: Francis Reed Wills, President, ADAGE Hamilton LLC, 225 Wilmington West Chester Pike, Suite 302, Chadds Ford, Pennsylvania 19317.

Facility Location: ADAGE Hamilton LLC proposes to construct the new ADAGE Power Plant that will be located in Hamilton County, at the intersection of State Road 6 and County Road 146, immediately west of Interstate Highway 75 and approximately 7.5 miles west of Jasper, Florida.

History: On October 8, 2009, the Permitting Authority gave notice of its intent to issue an air permit to the applicant for the project described below. The applicant published notice of the Public Notice of Intent to Issue Air Permit for this project on October 14, 2009, in The Suwannee Democrat and on October 15, 2009, in The Jasper News. During the public comment period, the Permitting Authority received written comments that resulted in substantial modifications to the intended air permit for this project. As a result of these substantial modifications, the Permitting Authority has withdrawn the October 8, 2009, intended air permit and has issued notice of its intent to issue a Revised Draft Permit for the project described below.

Project: The fuel for the ADAGE Power Plant will be clean woody biomass including: clean untreated lumber; tree stumps; tree limbs; slash; wood residue; bark; sawdust; sander dust; wood chips; scraps; slabs; millings; shavings; pallets; and processed pellets made from wood or other forest residues. The fuel will be combusted in a bubbling fluidized bed (BFB) boiler to produce 55.5 megawatts (net) of electric power. Natural gas, ultralow sulfur fuel oil or propane will be used for BFB startup and stabilization.

Based on the air permit application, the project will result in emissions increases of: 247.5 tons per year (TPY) of carbon monoxide (CO); 236 TPY of nitrogen oxides (NO_X); 140 TPY of particulate matter (PM); 110 TPY of PM with a mean diameter of 10 micrometers (μm) or less (PM_{10}); 26 TPY of sulfuric acid mist (SAM); 150 TPY of sulfur dioxide (SO_2); 60 TPY of volatile organic compounds (VOC); 0.175 TPY of lead (Pb) and 9.7 TPY of hydrogen chloride (HCl). A review for the Prevention of Significant Deterioration (PSD) and a best available control technology (BACT) determination were not required.

To insure that emissions are less than the respective major source thresholds for PSD and hazardous air pollutants (HAP) and that compliance is achieved with applicable new source performance standards, ADAGE will install or implement the following air pollution control equipment and practices on the BFB boiler: fabric filters and good combustion design and practices (PM, PM_{10}, CO, VOC); selective catalytic reduction (NO_X, VOC and dioxin furan); and inherently low sulfur fuels and an induct sorbent injection system (HCl, SAM, SO_2). Continuous emissions monitoring systems (CEMS) will be installed for SO_2, NO_X, CO and HCl. Emissions from emergency support equipment shall be controlled by use of clean fuels and good combustion and design. Reasonable precautions will be employed to minimize emissions from biomass handling, storage and processing.

The Department reviewed an air quality analysis prepared by the applicant. The analysis demonstrated that the sum of ground-level concentrations of nitrogen dioxide (NO_2), PM_{10}, CO and SO_2 caused by the project and background concentrations will be much less than the respective National or Florida ambient air quality standards (AAQS).

The Technical Evaluation and Preliminary Determination document and the air quality analysis are available at the following web link:

www.dep.state.fl.us/air/emission/construction/adagetech.pdf

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, 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 32301 and the mailing address is 2600 Blair Stone Road, MS #5505, Tallahassee, Florida 32399-2400. The Bureau of Air Regulation's phone number is 850/488-0114.

PUBLIC NOTICE OF INTENT TO ISSUE AIR PERMIT

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 Revised 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 and phone number listed above. In addition, electronic copies of these documents are available at the following web link:

www.dep.state.fl.us/Air/emission/construction/adage.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 applicable 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 Revised 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 Revised 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 this 14-day period. If timely received comments result in a significant change to the Revised Draft Permit, the Permitting Authority shall revise the Revised Draft Permit and require, if applicable, another Public Notice. All comments filed will be made available for public inspection.

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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; (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 in this proceeding.

(Public Notice to be Published in the Newspaper)

REVISED TECHNICAL EVALUATION

&

PRELIMINARY DETERMINATION

APPLICANT

ADAGE Hamilton, LLC
225 Wilmington West Chester Pike, Suite 302
Chadds Ford, Pennsylvania 19317

ADAGE Biomass Power Plant
ARMS Facility ID No. 0470016

PROJECT

Project No. 0470016-001-AC

55.5 Megawatt (net) Woody Biomass Power Plant

COUNTY

Hamilton County, Florida

PERMITTING AUTHORITY

Florida Department of Environmental Protection
Division of Air Resource Management
Bureau of Air Regulation
Special Projects Section
2600 Blair Stone Road, MS#5505
Tallahassee, Florida 32399-2400

December 10, 2009

1. APPLICATION INFORMATION

1.1. Applicant Name and Address

ADAGE Hamilton LLC (ADAGE)
225 Wilmington West Chester Pike, Suite 302
Chadds Ford, PA 19317

Authorized Representative: Mr. F. Reed Wills, President

1.2. Key Dates

- May 20, 2009 Received air construction permit application from ADAGE.
- October 8 Department distributed Draft Permit package and posted documents.
- October 14 Public Notice was published in the Suwannee Democrat.
- October 15 Public Notice was published in the Jasper News.
- October 21 ADAGE requested an extension of time to file a petition until November 23.
- November 23 ADAGE requested a second extension of time to file a petition until December 23.
- December 8 Settlement Stipulation signed by the Department and ADAGE.
- December 10 Department issued Revised Draft Permit package and posted documents.

1.3. Facility Location

The proposed plant will be located in Hamilton County at State Road 6 and County Road 146, just west of the Interstate 75 and State Road 6 interchange. The location is approximately 45 kilometers (km) southeast of Valdosta, Georgia and approximately 11 km west of Jasper, Florida. The approximate UTM coordinates for this site are Zone 17; 301.650 km East and 3,377.350 km North.

The location and layout of the proposed site is shown in Figures 1 and 2. The proposed site outlined by the yellow dashed lines comprises 215 acres. The footprint of the proposed plant will occupy roughly 50 acres in the southeast corner of the property. Figure 3 is a view of the ADAGE reference woody biomass power plant.

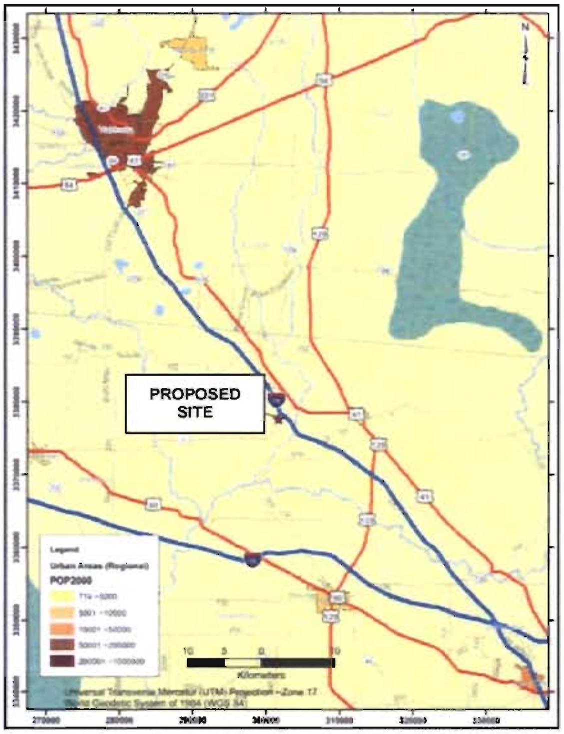

Figure 1 - ADAGE site, Hamilton County

Figure 2 - Project Layout On site

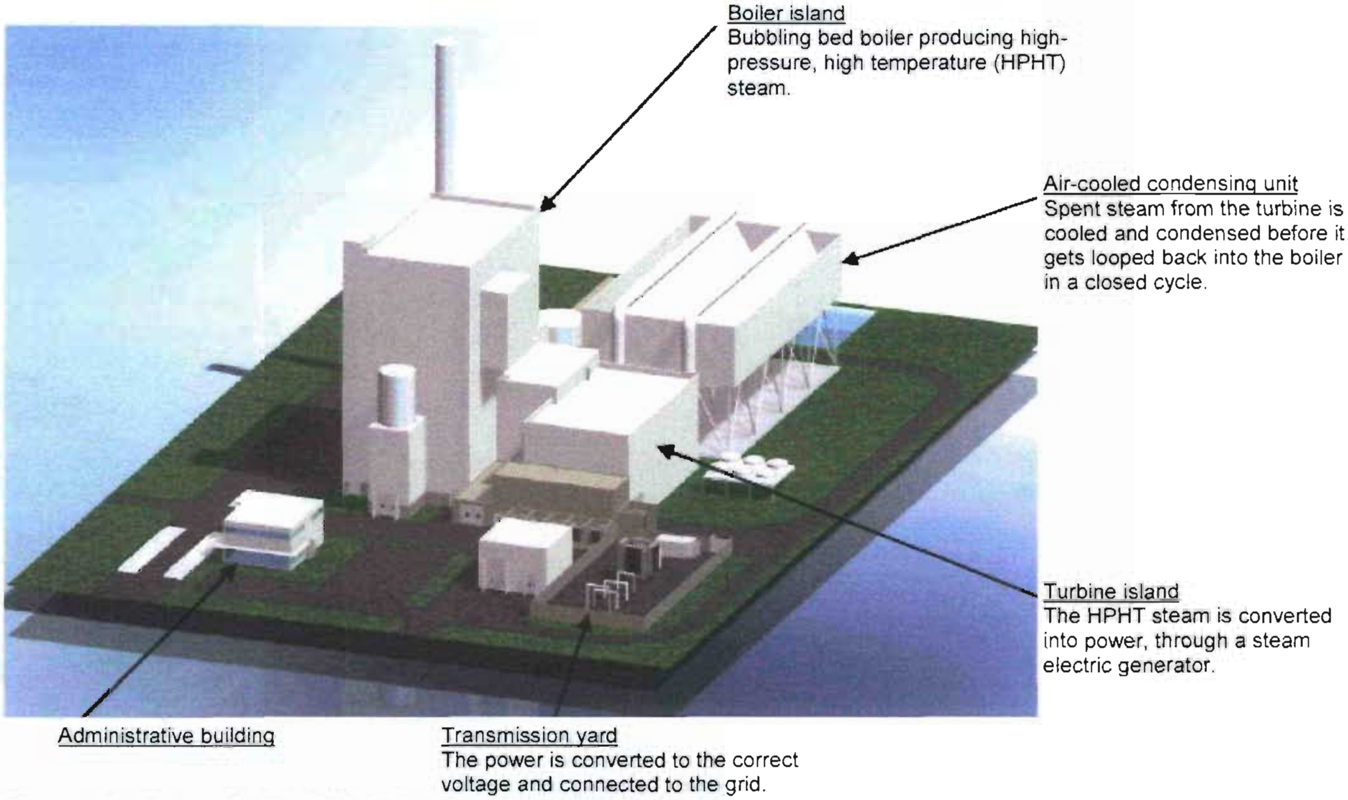

Figure 3 – View of ADAGE Reference Woody Biomass Power Plant

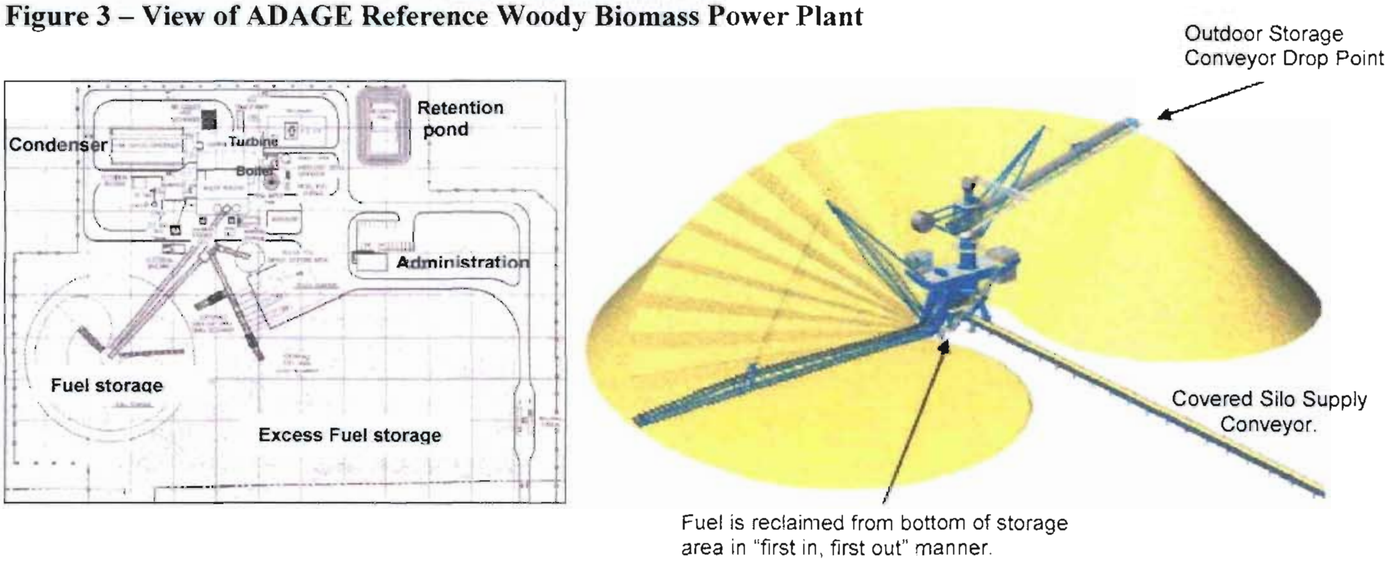

Figure 4 – Proposed Layout of Plant, View of ADAGE Reference Outdoor Storage Design

1.4. Regulatory Classification

Provided below is a summary of regulatory categories that apply to the proposed net 55.5-megawatt (MW) woody biomass power plant.

Standards of Performance for New Stationary Sources

- 40 CFR 60, Subpart A – General Provisions;
- 40 CFR 60, Subpart Db – Industrial, Commercial, Institutional Steam Generating Units; and
- 40 CFR 60, Subpart IIII – Stationary Compression Ignition Internal Combustion Engines (ICE).

National Emissions Standards for Hazardous Air Pollutants (NESHAP)

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

- 40 CFR 63, Subpart ZZZZ – Stationary Reciprocating Internal Combustion Engines (RICE).

Title IV, Acid Rain Provisions

The facility will be subject to the Title IV, Acid Rain Provisions of the Clean Air Act. The proposed plant will serve an electric generator capable of generating 25 MW or more of electricity and will sell the resultant electricity.

Title V, Permits

The facility is a Title V or "Major Source" of air pollution because the potential to emit (PTE) of at least one regulated pollutant will exceed 100 TPY. Key regulated pollutants include carbon monoxide (CO), nitrogen oxides (NO_X), particulate matter ($PM/PM_{10}/PM_{2.5}$), sulfur dioxide (SO_2) and volatile organic compounds (VOC).

Prevention of Significant Deterioration (PSD)

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

Clean Air Interstate Rule (CAIR)

The ADAGE facility is subject to CAIR in accordance with the Final Department Rules issued pursuant to CAIR as implemented by the Department in Rule 62-296.470, F.A.C.

Power Plant Siting

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

2. PROPOSED PROJECT

2.1. Project Description

The applicant proposes to construct a woody biomass electric power plant. The proposed plant will be capable of generating approximately 62 MW (i.e. gross) of electrical power by combusting woody biomass in a bubbling fluidized bed (BFB) boiler and associated steam turbine-electrical generator (STG). The plant will export approximately 55.5 MW (i.e. net) after deducting the parasitic load required to operate the plant.

The power plant will be comprised of four process areas. These process areas include:

- Fuel receiving, handling, storage and processing;
- Power island (steam generating unit), including a BFB boiler, air cooled condenser and STG;
- Ash handling, storage and shipment; and
- Emergency support equipment.

2.2. Additional Project Features

Fuel

ADAGE proposes to fuel the new BFB boiler with only clean woody biomass under normal operation. Natural gas (NG), propane or ultralow sulfur distillate (ULSD) fuel oil (FO) will be used for startup, shutdown and bed stabilization of the boiler only. NG may be provided to the site via a pipeline depending upon completion of gas projects planned in the region. Propane, if utilized, will be provided by an aboveground storage tank. ULSD FO will be stored on site.

Air Pollution Controls

The proposed power plant will utilize the following control devices and techniques to control air pollutants, as described below:

Fuel Receiving, Handling, Storage and Processing

- Employment of a first-in/first-out stacking and reclaiming system with minimal drop lengths to minimize dust generation, biological degradation and odors.
- All conveyor systems in the fuel receiving, handling, storage and processing system will be designed to minimize emissions of $PM/PM_{10}/PM_{2.5}$ through the use of Best Management Practices (BMP).
- BMP will include enclosed conveyors, to the extent possible enclosed chutes for dropping fuel to and from conveyors, and maintenance of paved roads to minimize fugitive dust generating materials on roadways.
- Other reasonable precautions as described in Rule 62-296.320(4)(c), F.A.C.

Power Island

- Emissions of $PM/PM_{10}/PM_{2.5}$ from the BFB boiler will be controlled by a fabric filter baghouse.
- SO_2 and sulfuric acid mist (SAM) from the BFB boiler will be controlled by use of inherently low sulfur wood and fossil fuels, reaction with alkaline fly ash and a dry in-duct sorbent injection system (IDSIS).
- NO_X from the BFB boiler will be controlled by an ammonia (NH_3) based selective catalytic reduction (SCR) system.
- Emissions of CO and VOC from the boiler will be controlled by the BFB design including good combustion practices (GCP).
- Emissions of HAP from the BFB boiler will be controlled by use of GCP, use of untreated woody biomass (inherently low in chloride), reaction with alkaline fly ash, the IDSIS, the fabric filter baghouse and the SCR system.

Ash Handling, Storage and Shipment

- Emissions of $PM/PM_{10}/PM_{2.5}$ from the fly ash silo will be controlled by a baghouse or similar filter.
- Best Management Practices will be utilized during truck loading operations to minimize PM/PM_{10} emissions.

Emergency Support Equipment

- Emergency Equipment will be designed to meet the emission limits given in NSPS Subpart IIII and NESHAP Subpart ZZZZ.
- ULSD FO will be utilized and operation of support equipment will be limited to 250 hours per year or less per unit.

3. PROCESS DESCRIPTION

3.1. Principle

The steam generating unit will utilize a nominal 758 million Btu per hour (mmBtu/hr) BFB boiler with a 4-hour total maximum heat input capacity of 834 mmBtu/hr. The maximum heat input capacity of the fossil fuels portion to the unit is 240 mmBtu/hr. The steam produced will then be sent to a STG that will generate approximately 62 MW (gross) of electricity of which approximately 55.5 MW will be delivered to the grid.

The fuel receiving, handling, storage and processing operations will be capable of receiving, handling, storing and delivering the clean woody biomass to the BFB boiler.

Residual ash collected by the boiler system baghouse will be conveyed and stored for future shipment offsite by truck. An emergency generator, fire pump and BFB coolant pump will be used in the event emergency situations arise at the plant. Figure 5 is a general process flow diagram of the operations at the proposed ADAGE plant. Details of a Babcock and Wilcox (B&W) BFB boiler and its fluidized bed are provided in Figure 6.

3.2. Fuel Slate and Sources

The feedstock to the BFB boiler will consist of woody biomass. Most of the woody biomass will be processed at a remote fuel preparation area (or areas) where it will be sorted, screened and chipped to size.

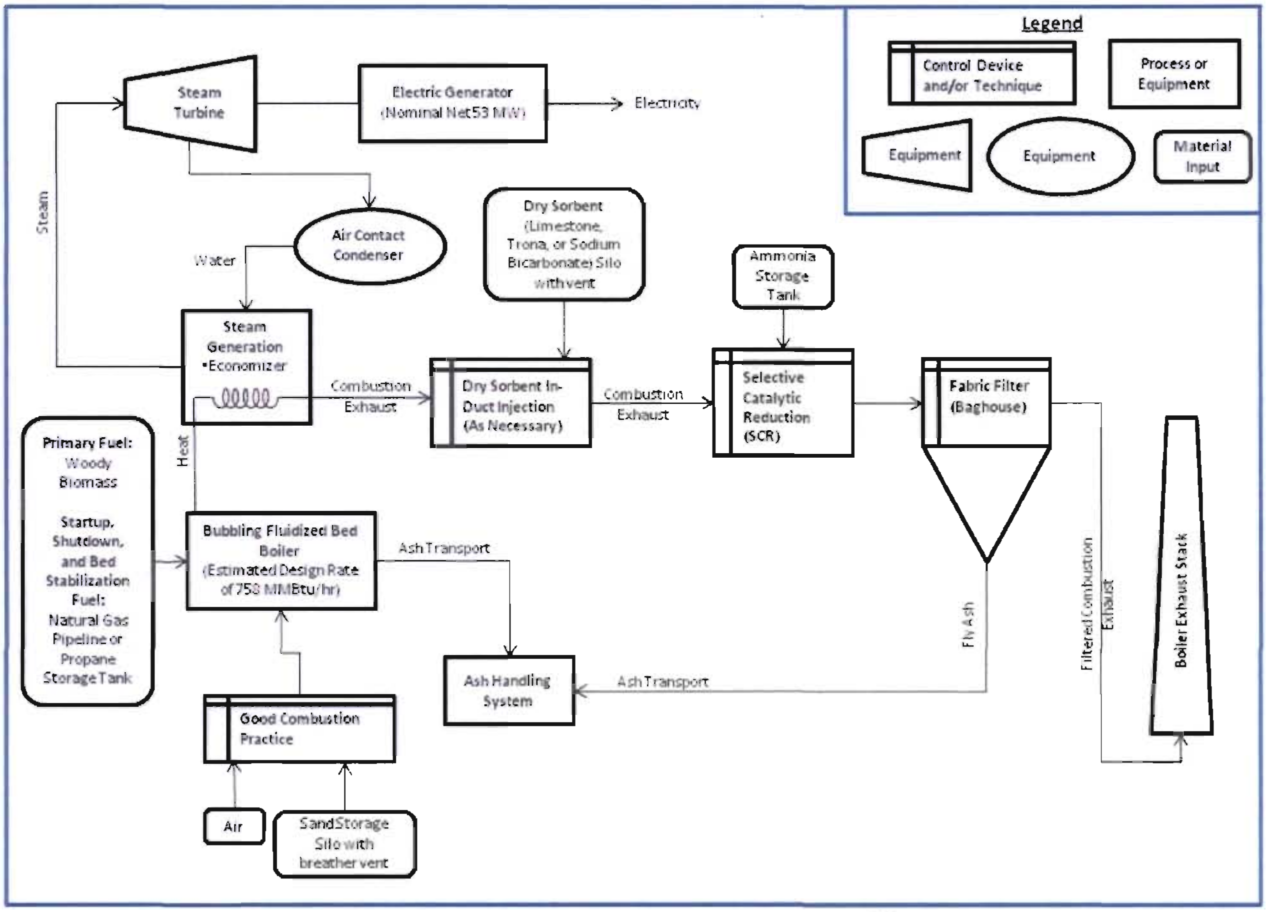

Figure 5 – Process Flow Diagram of ADAGE Woody Biomass Power Plant

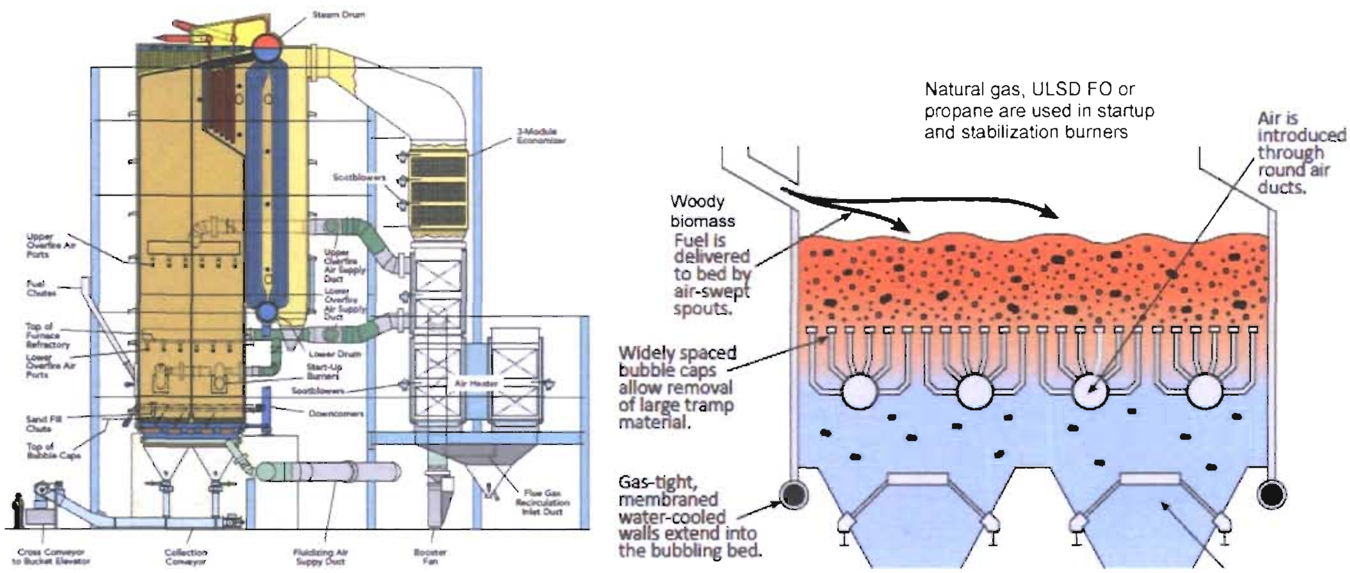

Figure 6 – B&W BFB Boiler for Woody Biomass, Operating Principle of Bubbling Fluidized Bed

ADAGE will only use clean woody biomass in the proposed BFB boiler. The clean, untreated woody biomass will include: clean untreated lumber; tree stumps; tree limbs; slash; wood residue, bark; sawdust; sander dust; wood chips and pellets; scraps; slabs; millings; shavings; and processed pellets made from wood or other forest residues.

Table 1 below further identifies types of woody biomass to be combusted in the BFB boiler.

Table 1 - Summary of Woody Biomass Fuel Descriptions

Fuel Group	Description
Field residuals and slash	Tops, limbs and whole tree soft or hardwoods that result from harvesting and/or thinning as well as the residue therefrom
Understory	Forest understory including smaller trees and saplings
Land clearing and storm debris	Tree parts and/or branches that have been cut down for land development or line clearing purposes or that have been gathered after storms.
Production residuals	Butts, sticks, pole ends and tree surgeon material
Saw mill waste	Saw dust and kerf waste from cutting/milling whole green trees
Planer mill shavings	Fines from planing kiln-dried lumber
Source separated construction wood waste	Clean construction wood waste that was a primary mill product and has not been treated in any way such as pallets, dimensional lumber, clean wood trim, and clean milled lumber

ADAGE further clarified that clean wood excludes secondary residues, such as plywood, particle board, medium density fiberboard (MDF), oriented strand board (OSB), laminated beams, finger jointed trim, and sheet goods. These secondary residues and other materials not on the list cannot be used as fuel without prior approval of the Department.

ULSD FO, NG or propane will also be used in the BFB boiler for startup, shutdown and bed stabilization. The heat input for NG, ULSD FO or propane will not exceed 240 mmBtu/hr.

3.3. <u>Fuel Receiving, Handling, Storage and Processing</u>

Woody Biomass

The fuel receiving, handling, storage and processing area is being designed to accommodate woody biomass, primarily in the form of pre-processed chips. The preliminary schematic of the flows is shown in Figure 7.

Woody biomass of the kinds described above will be brought to the site in covered trucks. The trucks will enter most likely on the south side of the plant and will proceed to the scale station for weighing. The trucks will then proceed to the truck dumping stations where the contents (i.e. chipped biomass) of the truck will be emptied into receiving hoppers. Some receiving hoppers will be accessed by material handling equipment. Most of the woody biomass to be received by the plant will be chipped off site.

The main storage pile will be built and managed on the principle of first-in/first-out as discussed above. 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. As previously mentioned first-in/first-out operation will minimize dust generation, biological degradation and odors.

NG, Propane and ULSD FO

NG, propane or ULSD FO will be used during startup and for stabilization. The extent to which each is used depends on the progress of nearby gas supply projects that may ultimately deliver NG to the proposed plant site. Propane and ULSD FO, if utilized, will be stored in above ground storage tanks.

3.4. Ash Handling, Storage and Shipment

Bottom ash from the BFB boiler will be removed from the boiler and stored in a metal container for future removal off-site. Fly ash captured in the pollution control equipment will be transported by an enclosed conveyor to the fly ash storage silo. The storage silo will be equipped with a small baghouse to minimize dust. Fly ash from the storage silo will be sent to a truck loading operation for removal off-site. The conveyor system will be enclosed and the chute used to dispense fly ash into the truck will be designed to minimize fugitive dust emissions.

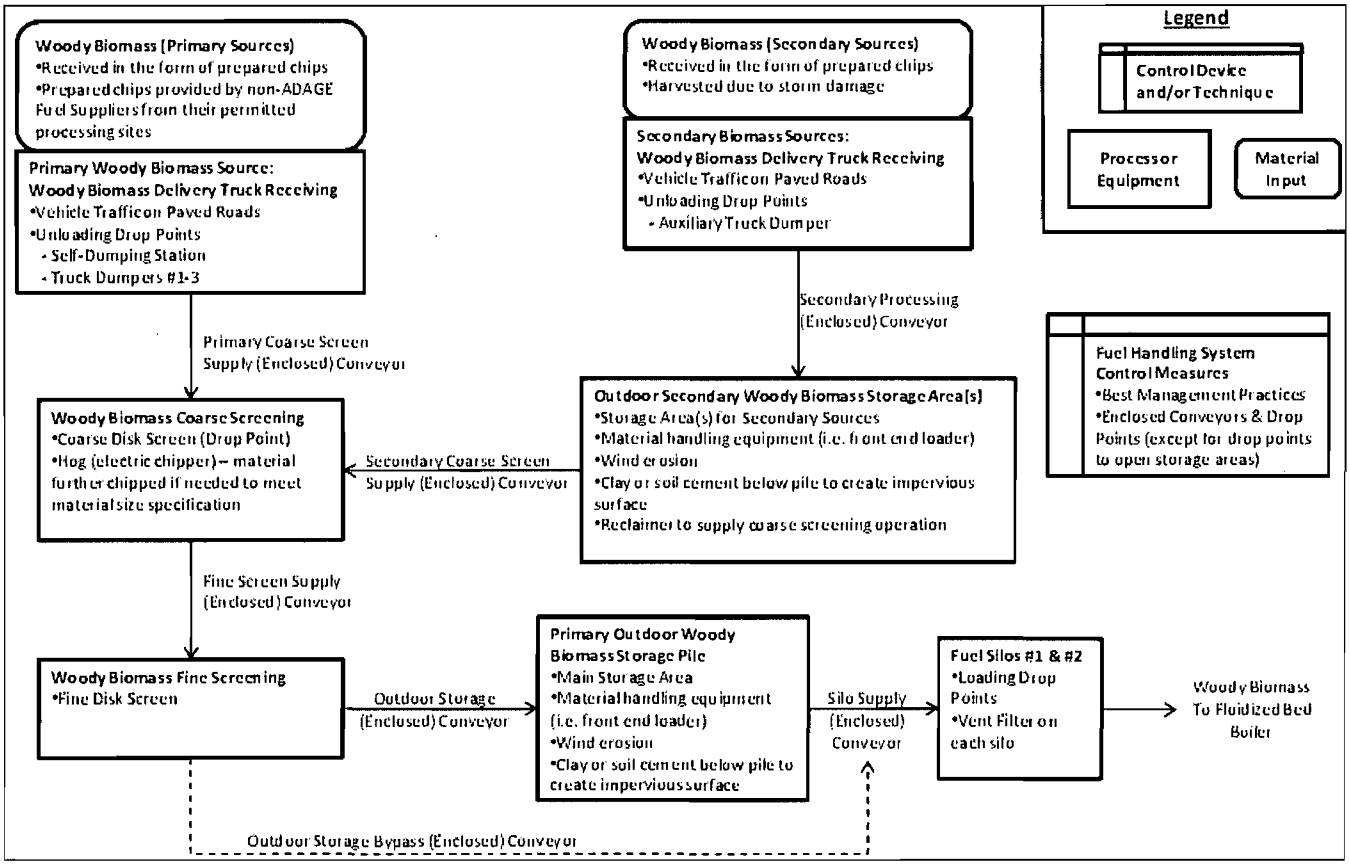

Figure 7 - Fuel Handling, Processing, and Storage Process Flow Schematic Diagram

A process flow diagram of the ash handling, storage, and shipment system is provided in Figure 8 below.

3.5. Emergency Support Equipment

The proposed plant will also require:

- One 1,800 kilowatt (kW) emergency electrical generator (or smaller);
- One 500 horsepower (hp) emergency fire water pump;
- One 500 hp emergency boiler cooling water pump; and
- One 500 gallon above ground storage tank for ULSD FO.

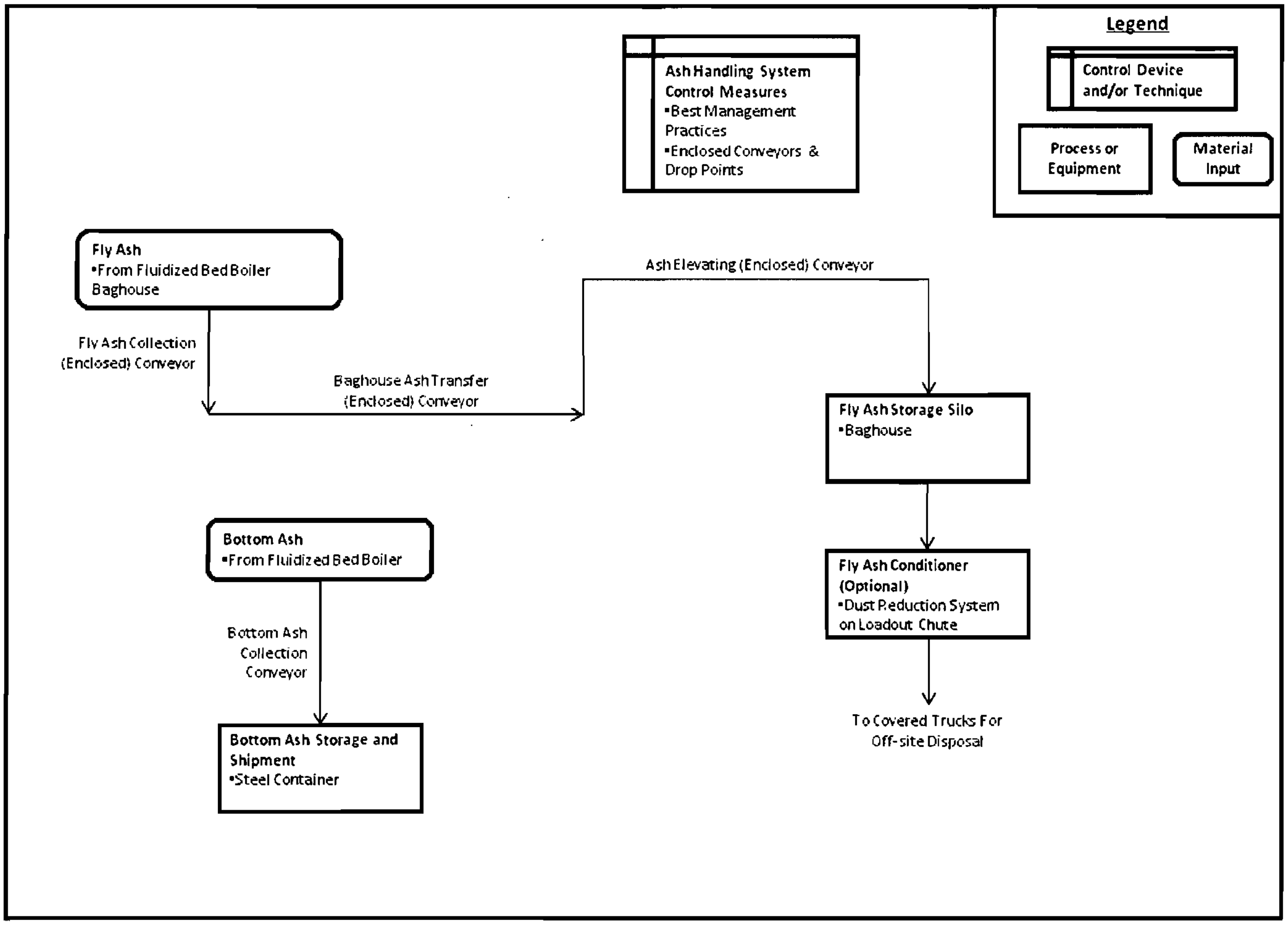

Figure 8 – Ash Handling, Storage and Shipment Process Flow Schematic Design

3.6. State Regulations

The project is subject to the applicable environmental laws specified in Section 403 of the Florida Statutes (F.S.) and to the following rules in 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 of Air Pollution
62-214	Requirements for Sources Subject To the Federal Acid Rain Program
62-296	Stationary Sources - Emission Standards
62-297	Stationary Sources - Emissions Monitoring

3.7. Potential Emissions and PSD Non-Applicability Determination

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

1. *Any of the following stationary sources of air pollutants which emits, or has the PTE, 100 TPY or more of any PSD pollutant:*
    - *Fossil fuel-fired steam electric plants of more than 250 mmBtu/hr heat input,*
    - *Coal cleaning plants (with thermal dryers),*
    - *Kraft pulp mills,*
    - *Portland cement plants,*
    - *Primary zinc smelters,*
    - *Iron and steel mills,*
    - *Primary aluminum ore reduction plants,*
    - *Primary copper smelters,*
    - *Municipal incinerators capable of charging more than 250 tons per day (TPD) of refuse,*
    - *Hydrofluoric, sulfuric, or nitric acid plants,*
    - *Petroleum refineries,*
    - *Lime plants,*
    - *Phosphate rock processing plants,*
    - *Coke oven batteries,*
    - *Sulfur recovery plants,*
    - *Carbon black plants (furnace process),*
    - *Primary lead smelters,*
    - *Fuel conversion plants,*
    - *Sintering plants,*
    - *Secondary metal production plants,*
    - *Chemical process plants,*
    - *Fossil-fuel boilers (or combination thereof) totaling more than 250 mmBtu/hr heat input,*
    - *Petroleum storage and transfer units with a total storage capacity exceeding 300,000 barrels,*
    - *Taconite ore processing plants,*
    - *Glass fiber processing plants,*
    - *Charcoal production plants;*
2. *Any stationary source which emits, or has the PTE, 250 TPY or more of a PSD pollutant; or*
3. *Any physical change that would occur at a stationary source not otherwise qualifying as a major stationary source, if the change would constitute a major stationary source by itself.*

The proposed plant category is not among the bulleted stationary sources listed in paragraph 1 above, that would be classified as a major stationary source based on the PTE 100 TPY of a regulated PSD air pollutant. To be considered a major stationary source, it would be necessary for the PTE from this project to equal or exceed 250 TPY of any regulated PSD air pollutant.

The project will result in emissions of NO_X, CO, particulate matter (PM, PM_{10} and $PM_{2.5}$), SO_2, small amounts of SAM (sometimes expressed as H_2SO_4), VOC and HAP.

Table 2 summarizes the applicant's estimates of key regulated air pollutants from the proposed woody biomass electric power plant. F stands for fluoride in the table.

Potential emissions of any regulated PSD air pollutant will not equal or exceed 250 TPY, based on operational design and associated emission limits. Therefore, the proposed woody biomass electric power plant will not be subject to the PSD rules including PSD ambient air modeling or a requirement for a best available control technology (BACT) determination under that program.

Table 2 - Estimated PTE Criteria Air Pollutants (in TPY)

Source Operation	PM	PM_{10}	$PM_{2.5}$	NO_X	SO_2	H_2SO_4	CO	VOC	F
Fluidized Bed Boiler	96.3			232.4	149.4	25.6	245.3	56.4	27.1
Biomass Handling and Processing	15.70	7.43	1.12	--	--	--	--	--	--
Fly Ash Handling	0.10	0.05	0.007	--	--	--	--	--	--
Boiler Support Material Handling	0.03	0.01	0.002	--	--	--	--	--	--
Emergency Generator & Storage Tank	0.09	0.09	0.09	2.9	0.003	0.0002	1.6	2.9	--
Emergency Boiler Coolant Water Pump & Storage Tank	0.02	0.02	0.02	0.4	0.12	0.01	0.3	0.6	--
Emergency Fire Pump & Storage Tank	0.02	0.02	0.02	0.4	0.12	0.01	0.3	0.4	--
In-plant Paved Roads	24.0	4.7	0.7	--	--	--	--	--	--
Biomass Pile Processing	1.0	0.08	0.01	--	--	--	--	--	--
Biomass Pile Wind Erosion	2.7	1.3	0.2	--	--	--	--	--	--
Project Total PTE Including Fugitive Sources	140	110	98.5	236	150	26	247.5	60	27

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

The proposed project is subject to the following NSPS regulations:

- NSPS Subpart A – General Provisions;
- NSPS Subpart Db – Industrial, Commercial, Institutional Steam Generating Units; and
- NSPS Subpart IIII – Stationary Compression Ignition Internal Combustion Engines.

The relevant emission standards presented in Table 3 include the NSPS Subpart Db emission standards applicable to the BFB boiler.

Table 3 - NSPS Subpart Db – Emission Standards Applicable to BFB Boiler

Source	SO_2 limit[1, 4] (lbs/mmBtu)	PM Limit[2] (lb/mmBtu)	Opacity[3] (%)	NO_X[4] (lb/mmBtu)
BFB Boiler	0.32	0.030	20%	0.20

1. Sources that achieve this limit are excluded from other SO_2 reductions under NSPS Db.
2. Filterable PM only.
3. 6-minute average, except for one 6-minute period per hour of not more than 27% opacity.
4. 30-day basis.

Tables 4 and 5 include the NSPS Subpart IIII emissions standards for the emergency generator and the two emergency pumps (fire and coolant).

Table 4 - NSPS Subpart IIII – Emission Standards Applicable to Emergency Generator

Emergency Generator (> 560 kW and ≤ 2,237 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	6.4

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

Table 5 - NSPS Subpart IIII – Emission Standards Applicable to two Emergency Pumps

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 ULSD FO in the two emergency pumps with a fuel sulfur content of 0.0015% by weight.

In addition to NSPS Subparts Db and IIII, other conditions and emission standards are required to insure that the facility-wide PTE of each PSD pollutant (excluding fugitive emissions) will be less than 250 TPY.

The emergency equipment associated with the proposed woody biomass power plant is also subject to the applicable area source requirements of NESHAP Subpart ZZZZ. This subpart requires all affected area source units to meet the applicable emission standards of Subpart IIII.

3.9. Other Department Rules Potentially Applicable to the Project

- Rule 62-296.401, F.A.C. - Incinerators;
- Rule 62-296.410, F.A.C. - Carbonaceous Fuel Burning Equipment;
- Rule 62-296.416, F.A.C. - Waste-to-Energy Facilities;
- Rule 62-296.406, F.A.C. – Fossil Fuel Steam Generators with Less than 250 mmBtu Heat Input, New and Existing Units; and
- Rule 62-296.320, F.A.C. - General Pollutant Emission Limitation Standards.

Incinerators and waste to energy facilities combust waste. The fuel slate authorized by this permit does not constitute a waste or municipal solid waste according to the Department's rules. Therefore, Rules 62-296.401 and 62-296.416, F.A.C. do not apply to this project.

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". The fuel slate described by the applicant falls into this category. Therefore, Rule 62-296.410, F.A.C. applies to this project. This provision includes a visible emissions standard of 30% opacity, a PM standard of 0.1 lb/mmBtu for the fossil fuel component and 0.2 lb/mmBtu for the carbonaceous fuel part.

The BFB boiler will use ULSD FO, NG or propane for startup, shutdown and bed stabilization. But the fossil fuel capability will be less than 250 mmBtu/hr of heat input. Therefore, Rule 62-296.406, F.A.C. applies to the extent that fossil fuel is burned in the BFB boiler. This section requires a BACT determination for PM and SO_2 and imposes a visible emissions standard of 20%. The BACT requirement for the fossil fuels will be satisfied by use of ULSD FO, propane or NG, the requirements of 40 CFR

Subpart Db, and the permit requirements intended to insure that the facility-wide PTE of PM and SO_2 are less than 250 TPY.

The project is subject to Rule 62-296.320, F.A.C., including provisions on VOC storage and handling; objectionable odor; open burning; visible emissions; and reasonable precautions to control fugitive emissions.

4. EMISSIONS FORMATION AND CONTROL

4.1. Emissions and Controls for the BFB Boiler

NO_X Emissions

Discussion: The BFB biomass fueled boiler has a maximum heat input rate of 834 mmBtu/hr on a 4 hour average basis with a maximum of 240 mmBtu/hr of heat input coming from fossil fuel (NG, ULSD FO or propane) for startup, shutdown and bed stabilization. Given in Table 6 below are the general characteristics of the BFB biomass-fueled boiler for the ADAGE project:

Table 6 - Characteristics of the BFB Biomass-fueled Boiler

Parameter	Description
Boiler Type	BFB design
Primary Fuel	Clean Woody Biomass at maximum rate of 100 tons per hour (TPH)
Supplemental Fuel	NG assuming that it is available. Otherwise, will fire ULSD FO or propane
Ash Removal	From baghouse to ash storage silo via enclosed conveyors
Heat Input Rate	Nominal 758 mmBtu/hr (maximum 834 mmBtu/hr on a 4-hour basis) of which a maximum of 240 mmBtu/hr is from fossil fuels
Thermal Efficiency	To be established
Steam Production	354,000 – 570,000 lb/hour (to be determined based on efficiency)
Stack Parameters	10.5 feet diameter (maximum); 195 feet tall (minimum)
Flue Gas	278,600 actual cubic feet per minute (acfm) at 310 °F
Particulate Control	Fabric filter baghouse greater than 99% efficiency
NO_X Control	Selective catalytic reduction (SCR) based on ammonia injection
SO_2 Control	Dry sorbent injection into ducting before baghouse, clean stabilization and backup fuel
VOC and CO Control	GCP

NO_X formation may occur by three different mechanisms: fuel NO_X is formed from nitrogen compounds contained in fuel (fuel nitrogen); thermal NO_X is formed from molecular or atomic nitrogen (N_2) and oxygen (O_2) present in combustion air; and prompt NO_X is formed in the proximity of the flame front as intermediate combustion products. The BFB biomass boiler is expected to emit 232.4 TPY of NO_X the majority of which will be thermal NO_X.

There are several NO_X reduction processes available including pre and post combustion control equipment. Selective non-catalytic reduction (SNCR) is a technology whereby NO_X emissions are controlled by reaction with NH_3 or urea at high temperature in the furnace. The products of the reaction are N_2 and water vapor (H_2O). SCR involves the same reaction but in the presence of catalyst and at lower temperature. The catalyst would be located in the dusty, medium temperature zone prior to other control equipment including particulate control devices.

A technology known as regenerative SCR (RSCR) is a recent development. It appears that the RSCR system can be used as an alternative to SNCR or SCR. However, the RSCR would be placed in a low temperature zone after all other control devices.

Applicant's Proposal for NO_X: The NSPS Subpart Db establishes a limit of 0.20 lbs NO_X/mmBtu on a 30 day rolling average. The applicant proposes an emissions cap of 232.4 TPY of NO_X from the boiler and to install SCR on the BFB boiler.

Department's Review. The selection of fluidized bed combustion (FBC), specifically of BFB design, is a primary NO_X control measure by itself. Following are some considerations (in quotes) by B&W when comparing the emission characteristics of a typical stoker furnace with a FBC furnace and, more specifically, one of BFB.

[In a stoker boiler] "The combustion zone temperature is typically neither measured nor controlled and can range from 2200 to over 3000 °F." This promotes the formation of thermal NO_X.

"The BFB bed temperature is both measured and controlled to an optimum temperature of approximately 1500 °F." This minimizes thermal NO_X formation but not fuel NO_X formation. According to B&W:

"Due to the improved combustion process previously described for a BFB, the uncontrolled (upstream of any post combustion air quality control systems) NO_X, CO and VOC emissions for a BFB are typically 10 to 25% less for a given biomass fuel than for a stoker. The BFB emissions are also less susceptible to variations in fuel properties that are inherent with any biomass plant. Under normal steady state operating conditions, both the BFB and stoker can be operated reliably within permitted emission limits.

"However, normal day-to-day operations in a typical plant are anything but steady state. Fuel variability is a fact of life, even when a conscious effort is made in the fuel yard to keep the fuel homogeneous. The large mass of bed material in the BFB creates a "flywheel effect," which is better suited to minimize spikes in emissions due to any changes in fuel characteristics. Conversely, the relatively low fuel inventory on a grate will typically be much more susceptible to an upset and potential emissions spikes, under changing fuel conditions."

For reference, some biomass projects comparable to the ADAGE project are listed in Table 7 below. The characteristics of the ADAGE project (though not actually proposed as limits) are given in the first row.

Some of the projects listed in the table triggered PSD for NO_X while others took synthetic minor limits to avoid triggering PSD or Non-Attainment New Source Review. All include use of biomass, wood chips or woody debris. Most projects, especially those imbedded within the RACT/BACT/LAER Clearinghouse (RBLC) survey, rely on SNCR or SCR.

The NO_X emission characteristics of the ADAGE project are comparable to emissions from projects that trigger PSD and a BACT determination as well as projects that took limits to avoid PSD and a BACT determination.

The Department accepts the NO_X proposal submitted by ADAGE but will add a mass emission rate limit that corresponds to the TPY cap requested by ADAGE. Therefore, the Department will set a limit of 53.1 lb/hr on a 12 month average basis, rolled monthly to insure that the PTE remains less than 250 TPY. The applicable NSPS Subpart Db limit of 0.20 lb/mmBtu on a 30-day rolling basis also applies. Compliance will be demonstrated by a NO_X continuous emission monitoring system (CEMS).

The annual cap proposed by ADAGE and the mass emission limit proposed by the Department equate to 0.070 lb/mmBtu at the nominal heat input rate of 758 mmBtu/hr and 0.064 lb/mmBtu at the maximum heat input rate of 834 mmBtu/hr if continuously operated.

Table 7 - Emissions in lb/mmBtu – Boilers with Uses or Capacities Similar to Proposed Project

Project Location	CO	VOC	NO_X	PM/PM_{10}	SO_2
ADAGE, Hamilton County, FL BFB – woody biomass ~758 mmBtu/hr (equivalents)	**~0.08** 12-month GCP	**~0.017** stack test GCP	**~0.070** 12-month SCR	**~0.029** stack test fabric filter	**~0.045** 12-month sorbent in ducts
HEF, Highlands County, FL stillage, wood, gas, ULSD FO ~198 mmBtu each (proposed)	0.10 30-day GCP	0.005 stack test GCP	0.075 30-day SNCR	0.01 Stack test fabric filter	0.06 30-day BFB limestone
Wheelabrator, Auburndale, FL grate boiler – wood and tires ~630 mmBtu/hr (1990s)	0.32 30-day GCP	0.035 stack test GCP	0.14 30-day SNCR	0.02 stack test fabric filter	0.10 30-day lime spray
U.S. Sugar Clewiston, FL grate boiler - bagasse ~1,000 mmBtu/hr (2003)	0.38 12-month GCP	0.05 Stack test GCP	0.14 30-day SNCR	0.26 stack test fabric filter	0.06 30-day no control
RBLC Survey All designs – any biomass ≥ 100 mmBtu/hr	0.1 – 0.63 typical 30-day GCP	0.005 – 0.05 stack test GCP	0.075-0.45 30-day various	0.0125 – 0.8 stack test various	0.02-1.54 typical 30-day various
Whitefield Power & Light, NH whole tree chips (WTC) 15 MW	Not known	Not known	0.075 guarantee RSCR	Not known	Not known
Boralex Stratton, ME WTC 50 MW	Not known	Not known	0.075 guarantee RSCR	Not known	Not known
Bridgewater Power, NH WTC 16 MW	Not known	Not known	0.075 guarantee RSCR	Not known	Not known
Burlington Electric, VT WTC 54 MW	Not known	Not known	0.065 guarantee RSCR	Not known	Not known
Palmer Springfield, MA construction/demolition (C&D) debris and WTC. 38 MW	Not known	Not known	0.065 guarantee RSCR	Not known	Not known
NSPS Subpart Db NG, wood, ULSD FO ≥ 100 mmBtu/hr	No standard	No standard	0.10-0.20 based on heat release rate	0.03 20% opacity wood basis	0.32 if achieved by low S fuels
NESHAP Subpart DDDDD[a] large solid fuel category ≥ 100 mmBtu/hr	~0.35 400 ppm @ 3% O_2[b] GCP	No standard	No standard	0.025 stack test	No standard

a. Subpart DDDDD was promulgated and then vacated

b. ppm @ 3% O_2 means parts per million by volume at 3 percent oxygen

SO_2 Emissions

Discussion. SO_2 is formed from sulfur compounds contained in biomass. According to the application, the BFB biomass boiler is expected to emit 149 TPY of SO_2. The clean woody biomass to be used by ADAGE will be typically low in S content. A figure of 0.034% S was originally provided in the application. This value is included in Table 8 along with heating value, ash and sulfur content of various types of biomass and fossil fuels. The values are on a dry basis except as otherwise noted.

Table 8 - Characteristics of Biomass and Fossil Fuels – Heating Value, Ash and S

Fuel Class	Fuel	Gross Heating Value Btu/lb	Ash (%)	S (%)
Bioenergy Feedstocks	**ADAGE woody biomass**	**8,500**	**5**	**0.034**
	cellulosic ethanol stillage	4,200 (wet)	7	0.08
	sweet sorghum	6,570	5.5	0.15
	sugarcane bagasse	7,720	3.2-5.5	0.10-0.15
	hardwood	8,745	0.45	0.009
	softwood	8,360	0.3	0.01
	hybrid poplar	8,105	0.5-1.5	0.03
	bamboo	8,085	0.8-2.5	0.03-0.05
	switchgrass	7,810	4.5-5.8	0.12
	miscanthus	7,785	1.5-4.5	0.1
	Arundo donax	7,295	5-6	0.07
Liquid Biofuels	bioethanol	11,940	~0	<0.01
	biodiesel	17,050	<0.02	<0.05
Fossil Fuels	coal (low rank)	6,400-8,100	5-20	1.0-3.0
	coal (high rank)	11,500-12,800	1-10	0.5-1.5
	ULSD FO	18,150	negligible	<0.0015
	NG	1,030 Btu/cubic foot	negligible	< 0.002

Applicant's SO_2 Proposal. The applicant proposes a limit of 0.18 lb SO_2/mmBtu on a 30-day rolling average. The applicant also proposes an emissions cap of 149.4 TPY of SO_2 from the boiler and to inject dry sorbent in the duct work prior to the PM control device, which consists of a fabric filter baghouse. The induct sorbent injection system (IDSIS) will use either limestone ($CaCO_3$), trona [$Na_3(CO_3)(HCO_3)\cdot 2(H_2O)$], or sodium bicarbonate ($NaHCO_3$) to augment the alkaline properties of the fly ash collected in the fabric filter baghouse.

Department's Review. According to Table 8, the woody biomass, NG and ULSD FO are all low in S content. Per 40 CFR 60.42b(k)(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 or less are exempt from SO_2 emissions limits in 40 CFR 60.42b(k)(1). The language is as follows:

(k)

(1) Except as provided in paragraphs (k)(2), (k)(3), and (k)(4) 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 commences construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, natural gas, a mixture of these fuels, or a mixture of these fuels with any other fuels shall cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 0.20 lb/mmBtu heat input or 8 percent (0.08) of the potential SO_2 emission rate (92 percent reduction) and 1.2 lb/mmBtu heat input. For facilities complying with the percent reduction standard and paragraph (k)(3) of this section, only the heat input supplied to the affected facility from the combustion of coal and oil is counted in paragraph (k) of this section. No credit is provided for the heat input to the affected facility from the combustion of natural gas, wood, municipal-type solid waste, or other fuels or heat derived from exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

(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.

It is known that the woody biomass categories within Table 8 contain insignificant amounts of sulfur with respect to potential (uncontrolled) emissions of 0.32 lb/mmBtu. Based on Table 8, the woody biomass to be burned by ADAGE will contain approximately 0.034% S by weight on a dry basis. The pre-control SO_2 emission potential is calculated as follows:

(0.034 lb S/100 lb biomass)(2 lb SO_2/lb S)(lb biomass/8,500 Btu)(10^6 Btu/mmBtu) = 0.08 lb SO_2/mmBtu.

This value is 25% of the 0.32 lb/mmBtu value given in 40 CFR 60.42b(k)(2). Any combination of biomass combustion with NG, propane or ULSD FO will result in even lower emissions. Therefore it is reasonable to conclude that the potential (uncontrolled) SO_2 emission rate is less than 0.32 lb/mmBtu and that the project is exempt from any additional SO_2 emission limits in Subpart Db without an additional limit of 0.18 lb/mmBtu.

To insure compliance with the 149.4 TPY cap, the Department will also include a limit of 34.1 lb SO_2/hr on a 12-month average, rolled monthly. The annual cap proposed by ADAGE and the mass emission rate limit proposed by the Department equate to 0.045 lb SO_2/mmBtu at the nominal heat input rate of 758 mmBtu/hr and 0.041 lb/mmBtu at the maximum heat input rate of 834 mmBtu/hr if continuously operated at those rates. The 12-month average 34.1 lb/hr limit is, on balance, more stringent than the unnecessary 30-day 0.18 lb/mmBtu limit proposed by the applicant. This is especially true with respect to insuring compliance with the proposed annual cap and avoidance of PSD.

According to 40 CFR 60.49(r),

(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.

The SO_2 emission characteristics of the ADAGE project are comparable to emission limits from projects that trigger PSD and a BACT determination as well as projects that took limits to avoid PSD and a BACT determination.

The separate Department SO_2 BACT requirement under Rule 62-296.406, F.A.C. for the fossil fuels will be satisfied by use of ULSD FO, propane or NG.

SAM Emissions

Discussion. SAM is formed by further oxidation of SO_2 to sulfur trioxide (SO_3) prior to exiting the process. SO_3 readily combines with water vapor (H_2O) available in flue gas to form SAM (H_2SO_4). SAM condenses on the cool surfaces in the exhaust duct, air pollution control equipment or on fly ash particles.

Applicant's SAM Proposal. The applicant does not propose a limit for SAM. According to the application and as a worst case, the BFB biomass boiler is expected to emit 9 lb SAM/hr from the boiler stack when burning woody biomass based on an emission factor of 0.012 lb SAM/mmBtu. Annual uncontrolled H_2SO_4 emissions are estimated at approximately 25.6 TPY from the boiler stack based on an emission factor of 0.0077 lbs/MMBtu.

Department's Review. It is doubtful that a woody biomass unit emitting 149 TPY of SO_2 will also emit 25.6 TPY of SAM. Excessive emissions of SAM are reflected as increased plume opacity. The Department will limit visible emissions to 10% opacity to insure compliance with $PM/PM_{10}/PM_{2.5}$ as discussed below. This requirement will discourage excessive emissions of SAM.

The applicant can specify SCR catalyst for NO_X control that is characterized by low conversion (oxidation) of SO_2 to SO_3. Sorbent injection coupled with fabric filtration will also tend to minimize SAM emissions.

The Department will not establish an actual SAM limit because it is clear that emissions will be much less than 250 TPY. Control of SO_2, opacity limitations and the $PM/PM_{10}/PM_{2.5}$ controls will minimize SAM emissions. The Department will require an initial stack test to determine the SAM emission characteristics of the BFB boiler.

CO Emissions

Discussion. CO is a product of incomplete combustion. Refer to Table 7 above for a listing of CO limits from biomass projects. Refer to the section on NO_X emissions for a discussion on the combustion characteristics of the BFB technology.

Applicant's Proposal. The NSPS Subpart Db does not establish limits on CO emissions. The applicant initially proposed an emissions cap of 232.4 TPY of CO (and no lb/hr limit) from the boiler by GCP on the BFB boiler to be demonstrated by use of a CO-CEMS.

Department's Review. Intimate contact between the bed material and the fuel results in burnout and low CO emissions. The Department will set a mass emission rate limit of 55.9 lb/hr on a 12 month average basis, rolled monthly to insure that the PTE is less than or equal to 245 TPY from the BFB and less than 250 TPY from the facility.

The mass emission rate limit proposed by the Department equates to 0.074 lb/mmBtu at the nominal heat input rate of 758 mmBtu/hr and 0.067 lb/mmBtu at the maximum heat input rate of 834 mmBtu/hr if continuously operated.

The CO emission characteristics of the ADAGE project are comparable to emissions from projects that trigger PSD and a BACT determination as well as projects that took limits to avoid PSD and a BACT determination. For reference, the recently vacated NESHAP Subpart DDDDD would have required compliance with a CO limit of 400 ppm @ 3% O_2 as a surrogate for organic HAP. This value is roughly equal to 0.35 lb CO/mmBtu.

The Department agrees that the proposed values represent BACT for CO and VOC.

VOC Emissions

Discussion. VOC is a product of incomplete combustion. Refer to Table 7 above for a listing of VOC limits from biomass projects. Refer to the section on NO_X emissions for a discussion on the combustion characteristics of the BFB technology.

Applicant's VOC Proposal. The applicant does not propose a limit for VOC. The applicant has estimated VOC emissions from the boiler at 13 lb/hr and 56.4 TPY. The basis was an annual average emission factor of 0.017 lb/mmBtu.

Department's Review. The Department will not establish an actual VOC limit because it is clear that emissions will be much less than 250 TPY. However, the Department will require an initial stack test to determine the VOC emission characteristics of the BFB boiler. The Department also notes that incorporation of SCR for NO_X control will help to reduce VOC emissions including organic HAP emissions such as dioxin and furan (D/F).

$PM/PM_{10}/PM_{2.5}$ and Visible Emissions (VE)

Discussion. $PM/PM_{10}/PM_{2.5}$ are formed from ash contained in the biomass, products of incomplete combustion and from chemical reactions between products of combustion that form alkali and ammoniated chlorides, sulfates, nitrates and other such species.

Applicant's Proposal. The applicant proposes a PM/PM_{10} limit of 0.029 lb/mmBtu (filterable *and* condensable fraction of PM/PM_{10}), based on a 3-hour EPA Methods 5 and 202 performance test. This limit will insure compliance with the NSPS Subpart Db PM limit of 0.03 lb/mmBtu (filterable fraction only) and the carbonaceous fuel PM limit under Rule 62-296.410, F.A.C. of 0.2 lb/mmBtu (filterable fraction only).

The proposal of 0.029 lb/mmBtu will limit emissions of $PM/PM_{10}/PM_{2.5}$ to 96.3 TPY (filterable and condensable) and well below 250 TPY PSD-threshold.

The applicant proposes to comply with a visible emissions (VE) limit of 20% (6-minute average) opacity, except for one 6-minute period per hour of not more than 27% opacity as measured by a continuous opacity monitoring system (COMS).

Department's Review. The Department will set a PM limit of 0.029 lb/mmBtu including filterable plus condensable PM as determined by initial and annual tests using Method 19. It will readily insure compliance with the Subpart Db and with Rule 62-296.410, F.A.C.

The separate Department PM BACT requirement under Rule 62-296.406, F.A.C. for the fossil fuels will be satisfied by use of ULSD FO, propane or NG.

The Department will also set a VE standard of 10% opacity (6-minute average), except for one 6-minute period per hour of not more than 15% opacity as measured by a COMS. The Department will establish a NH_3 limit of 10 parts per million, by volume at 7% O_2 (ppmvd) to be demonstrated by initial and annual tests using EPA Method 320. These limits are necessary for reasonable assurance that the unit will actually meet the applicant's proposed PM standard of 0.029 lb/mmBtu, which includes both the filterable and condensable fractions.

The NH_3 limit will be readily achieved by SCR.

Hydrogen Chloride (HCl) Emissions

Discussion. HCl is formed from chloride (Cl) compounds contained in biomass. According to the application, the BFB biomass boiler has the potential to emit 9.7 TPY of HCl. The woody biomass to be used by ADAGE will be typically low in Cl content. According to the applicant, all types of woody biomass to be combusted by ADAGE are estimated by the applicant to contain less than 0.015% Cl.

If HCl PTE is equal to or greater than 10 TPY, then the source would be a major source of HAP and a case-by-case determination of Maximum Achievable Control Technology (MACT) is required. Such a determination would result in emission limitations for HCl and at least several other pollutants or surrogates for those pollutants such as PM-metals or organic HAP.

Applicant's HCl Proposal. The applicant proposes the following program to control and measure HCl emissions from the proposed BFB boiler:

- *Emission of HCl shall be less than 9.7 tons during any consecutive 12-month rolling total;*
- *In accordance with good operating practices and the manufacturer's recommendations, the fabric filter system will be in operation at all times including startup and shutdown periods. The in-duct sorbent injection system will be in operation in accordance with the manufacturer's recommended operating practices as needed to maintain the minor source HCl emission rate of less than 10 tons during any consecutive 12-month period;*
- *The applicant shall demonstrate compliance with the HCl limit of 9.7 tons per consecutive twelve month period based on CEMS on the BFB boiler stack;*
- *While EPA has established a performance specification for Fourier Transform Infrared spectroscopy (FTIR) CEMS (PS-15) and while an extractive FTIR CEMs could in fact measure HCl, initial evaluation of the potential HCl CEMS suggests that a different technology, such as a non-dispersive infrared (NDIR) technique using gas filter correlation (similar to CO monitoring systems) or a tunable laser diode (TDL) system maybe a more reliable / accurate measurement device. Consequently the provisions of PS-15 will be largely inapplicable to the CEMs technology suggested above. Additionally PS-15 fails to address many of the issues that are critical to the performance of CEMs, such as determining calibration error or drift, setting instrument span range, or determining relative accuracy. These types of requirements are the cornerstone of EPA's other performance specifications for CEMS; and,*
- *Applicant proposes to work with instrument vendors and DEP to develop performance specifications, specific to a non-FTIR HCl CEMS within 90 days of permit issuance. The developed performance specification would be submitted to the Bureau for final approval. The performance specification developed and submitted by applicant will be structured similarly to established EPA performance specification formats for other types of monitoring, (e.g. EPA Performance Specification 2 in 40 CFR 60, Appendix B). The applicant requests that the Bureau approve or deny the performance specification within a reasonable period after receipt to allow adequate time to implement the approved compliance methodology. If applicant cannot find an instrument vendor willing to guarantee the performance specification ultimately approved by the Bureau or if such vendor ultimately fails to provide an instrument that does indeed meet the specification, applicant will provide to the Bureau an alternative compliance approach consisting of utilizing stack testing results and boiler operating parameters. Submission, review and acceptance of that alternative approach must be achieved prior to commercial operation of the woody biomass boiler.*

Department's Review. According to other sources consulted by the Department, untreated woody biomass will contain less than 0.02% Cl. The NG, ULSD FO and propane are even lower in Cl content.

The Cl can be released as HCl and or it can be bound to the ash. Cl can also condense in the form of alkali salts (NaCl and KCl) or as NH_4Cl in the presence of NH_3. Some Cl can react further with organic species forming organic HAP including D/F. Fortunately, the SCR unit installed for NO_X control will tend to destroy D/F.

If all Cl is converted to HCl, then the pre-control annual HCl emissions from the biomass boiler are calculated as follows:

[(0.02 lb Cl/100 lb biomass)x(2000 lb biomass/ton biomass)x(36.45 lb HCl/35.45 lb Cl)]x
[(ton HCl/2000 lb HCl)x(47 tons biomass/hr)x(8,760 hr/year)] = 84.7 TPY HCl

A conservative estimate is that as much as half of Cl will actually be converted to HCl. To insure that the PTE is limited to a value less than 10 TPY it will be necessary to use the in-duct sorbent injection system (IDSIS) described for SO_2 control to also control HCl. The HCl will be converted to a particulate salt depending on the sorbent used. It will be necessary to control HCl emissions by approximately 80%. This should be easily accomplished by the described IDSIS and fabric filter baghouse.

The Department will set a limit of 9.7 TPY of HCl on a 12-month rolling average, rolled monthly. Compliance shall be demonstrated by an HCl-CEMS. The 12-month limit equates to 2.22 lb/hr HCl. These limits equate to 0.0029 and 0.0026 mmBtu HCl/mmBtu at the nominal heat input rate of 758 mmBtu/hr and the maximum heat input rate of 834 mmBtu/hr, respectively.

The SCR installation, GCP in the BFB boiler, use of a non-gasification process, low Cl source biomass and control and measurement of HCl emissions will insure that organic HAP emissions including D/F will be adequately controlled.

5. STARTUP, SHUTDOWN AND MALFUNCTIONS – PROPOSED BFB BOILER

The boiler will be designed to accommodate ULSD FO, NG or propane for boiler startup, shutdown and boiler bed stabilization only. The maximum burner heat input will be limited to 240 MMBtu/hr.

Applicant's Proposal. The applicant has requested excess emissions resulting from startup, shutdown, and documented malfunctions shall be permitted, provided that operators employ the best operational practices to minimize the amount and duration of emissions during such incidents.

The applicant requests that excess emissions resulting from startup, shutdown, or documented malfunctions be permitted but not to exceed two hours in a 24-hour block except for the following specific cases.

a. BFB Boiler Startup: For startup of the BFB boiler, excess emissions shall not exceed twelve (12) hours in any 24-hour period. "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. [Rule 62-210.200(245), F.A.C.]

b. BFB Boiler Shutdown: For any BFB boiler shutdown excess emissions shall not exceed six (6) hours in any 24-hour period.

c. BFB Malfunctions: For any BFB documented malfunction, excess emissions shall not exceed two (2) hours in any 24-hour period. A "documented malfunction" means a malfunction that is documented within one working day of detection by contacting the Compliance Authority by telephone, facsimile transmittal, or electronic mail.

Department's Review. The applicable CEMS-based SO_2, NO_X, CO and HCl emissions limits are largely 30-day or 12-month rolling limits that do not provide for data exclusion per the applicable NSPS Subpart or the nature of emission caps for the purposes of avoiding PSD. PM/PM_{10} and VOC emissions are measured by a once per year test. The Department will not allow exclusion of any measured emission data.

The only other limit for which the excess emission rule could apply is opacity. In the case of the NSPS Subpart Db requirements, the 20% opacity standard (6-minute average) applies at all times except for one 6-minute period per hour of not more than 27 percent opacity and during periods of startup, shutdown, or malfunction.

The Department proposes a separate 10% opacity standard except for a single 6-minute period per hour of during which VE may not exceed 20% opacity. The Department will allow excess visible emissions as requested by the applicant by applying a standard of 20% during startups, shutdown and malfunctions expect for one 6-minute period per hour of not more than 27% opacity during periods of startup, shutdown and malfunction.

It is important to limit the occurrences of startups, shutdowns and malfunctions as well as the visible emissions (opacity) during those occurrences to insure that PSD is not triggered.

6. BEST MANAGEMENT PLAN TO CONTROL FUGITIVE EMISSIONS

Table 9 is a listing of the estimated fugitive emissions from the project.

Table 9 - Estimated Potential to Emit (PTE) Criteria Air Pollutants (TPY)

Source Operation	PM	PM_{10}	$PM_{2.5}$
Biomass Handling and Processing	15.70	7.43	1.12
Fly Ash Handling	0.10	0.05	0.007
In-plant Paved Roads	24.0	4.7	0.7
Biomass Pile Processing	1.0	0.08	0.01
Biomass Pile Wind Erosion	2.7	1.3	0.2
Project Total Fugitive Sources	43.5	13.6	2.0

Fugitive emissions are not counted in determining whether this particular project is subject to PSD. However, the Department requires adherence to Rule 62-296.320(4)(c), F.A.C., which specifies the types of reasonable precaution required to control unconfined emissions of PM.

Accordingly, the applicant submitted a Best Management Practices (BMP) plans that describe fugitive, storage pile BMP plans to comply with the rule and another to describe fire prevention and response procedures. The plans are provided in Tables 10, 11, 12 and 13 below.

Table 10 - BMP for Storage Pile Management

- Woody biomass storage areas shall be managed to avoid excessive wind erosion.
- A woody biomass fugitive dust management plan shall be developed and maintained onsite. Plan shall identify warning signs for conditions that could result in excessive fugitive dust formation. Plant personnel shall be trained on what warning signs to look for.
- Mechanical moving of woody biomass by front end loaders and other supporting equipment shall be minimized on high wind event days.
- Daily visual observations of the woody biomass storage areas shall be performed and if conditions are right for fugitive dust formation, procedures from the fugitive dust plan shall be implemented.
- To control odors the clean woody biomass will be utilized in the first in first out basis.

Table 11 - BMP for Minimization of Fugitive Dust Emissions

- Conveyor systems and associated drop points shall be enclosed or partially enclosed.
- Drop points to woody biomass storage areas shall be designed to minimize the overall exposed (or exposed to atmosphere) drop height.
- Periodic equipment maintenance shall be performed to maintain conveyor systems and associated drop point integrity. Appropriate plant records shall be maintained on equipment maintenance performed.
- Fuel silos shall be equipped with vent filters.
- Daily observations of the conveyor systems and associated drop point integrity to identify any equipment abnormalities.
- Plant personnel shall be trained on identification of warning signs for potential equipment malfunction.
- Signs shall be posted identifying potential warning signs of equipment malfunction.
- Procedures shall be established for defining excessive fugitive dust from woody biomass truck unloading operations. Plant personnel shall visually observe truck unloading operations, including self unloading/dumping operations, and if excessive fugitive dust is detected appropriate fugitive dust minimization techniques shall be implemented. Plant personnel shall be trained on procedures for defining and minimizing excessive dust from the truck unloading operations.
- All major roadways at the plant shall be paved.
- Mud, dirt or similar debris shall be removed promptly from the paved roads.
- Plant personnel shall be trained on what constitutes excessive dust on paved road.

Table 12 - BMP for Fire Prevention / Spontaneous Combustion Minimization Practice

- Contact local fire marshal to develop fire management plan. Plan shall be maintained on site.
- Fire Management plan to 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.
- Daily observations 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.
- Signs shall be posted at the plant, which identify potential fire hazards.
- Incoming unprocessed materials shall be stored in areas with a clearance between each storage area.
- The stacker reclaimer being used shall maximize the removal of older material in order to minimize the stacking of newer material on top of older material.
- Compaction of woody biomass materials in the storage areas shall be minimized.

Table 13 - BMP for Quality Assurance of Clean Woody Biomass

- The feedstock for the bubbling fluidized bed (BFB) boiler will consist of clean woody biomass that will be processed in designated fuel preparation area (or areas) where it will be sorted, screened, and sized as necessary, placed in the storage areas or sent directly to the BFB boiler.
- The permittee will contract for woody biomass that specifically meets the definition of woody biomass as identified in the permit. The woody biomass will consist of clean untreated wood or untreated wood products including clean untreated lumber, tree stumps (whole or chipped), tree limbs (whole or chipped) and slash. This also includes, but is not limited to, wood, wood residue, bark, or any derivative fuel or residue thereof, in any form, including but not limited to sawdust, sander dust, wood chips, scraps, slabs, millings, shavings, and processed pellets made from wood or other forest residues.
- The woody biomass feedstock will be delivered to the Hamilton County Plant in vehicles designed to prevent release.
- For each shipment of woody biomass, the permittee shall record the date, quantity and a description of the material received.
- 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.
- The permittee shall maintain records of rejected shipments and disposition thereof. Such records shall be made available to the Department upon request.

7. AMBIENT AIR QUALITY

7.1 Introduction

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

7.2 Major Stationary Sources Nearest to the Project

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

Table 14 - Largest Sources of SO_2 Nearest to the Project

Owner	Site Name	TPY
Jacksonville Electric Authority	Northside/St. Johns River Power Park	12,019
Gainesville Regional Utilities	Deerhaven Generating Station	7,622
Smurfit Stone Container	Fernandina Mill	4,340
White Springs AgriChem	White Springs AgriChem	3,369
Buckeye	Buckeye Taylor	2,195
Cedar Bay	Cedar Bay Cogen	1,957
Rayonier Performance Fibers	Fernandina Sulfite Mill	888
IFF Chemical Holdings	IFF Chemical Holdings Duval	746
Millennium Specialty Chemicals	Jacksonville Plant	408
Anchor Glass	Jacksonville Plant	305
Progress Energy	Suwannee River Plant	265
ADAGE Hamilton	**ADAGE (proposed)**	**149**
E.I. Dupont de Nemours & Co	Trailridge Clay	120

Table 15 - Largest Sources of PM/PM_{10} Nearest to the Project

Owner	Site Name	TPY
Buckeye	Buckeye Taylor	689
Smurfit Stone Container	Fernandina Mill	618
Jacksonville Electric Authority	Northside/St. Johns River Power Park	537
Cedar Bay	Cedar Bay Cogen	172
Rayonier Performance Fibers	Fernandina Sulfite Mill	140
Gainesville Regional Utilities	Deerhaven Generating Station	140
ADAGE Hamilton	**ADAGE (proposed)**	**140**
Gilman Building Products	Gilman Building Products	87
Florida Rock Industries	Thomas S. Baker Cement Plant	73
Owens-Corning	Jacksonville Plant	72

Table 16 - Largest Sources of CO Nearest to the Project

Owner	Site Name	TPY
Buckeye	Buckeye Taylor	6,081
Jacksonville Electric Authority	Northside/St. Johns River Power Park	5,988
Rayonier Performance Fibers	Fernandina Sulfite Mill	1.125
Smurfit Stone Container	Fernandina Mill	978
Florida Rock Industries	Thomas S. Baker Cement Plant	676
Suwannee American Cement	Suwannee American Cement	663
Cedar Bay	Cedar Bay Cogen	540
Gerdau Ameristeel	Jacksonville Mill	379
City of Tallahassee	Arvah Hopkins Power Plant	365
ADAGE Hamilton	**ADAGE (proposed)**	**248**
Gainesville Regional Utilities	Deerhaven Generating Station	232
Nassau County	West Nassau Landfill	202

Table 17 - Largest Sources of VOC Nearest to the Project

Owner	Site Name	TPY
Smurfit Stone Container	Fernandina Mill	994
Buckeye	Buckeye Taylor	627
Rayonier Performance Fibers	Fernandina Sulfite Mill	354
Gilman Building Products	Gilman Building Products Taylor	223
Jacksonville Electric Authority	Northside/St. Johns River Power Park	187
Ball Container	Ball Container Gainesville	173
Johnson & Johnson Vision	Vistakon	165
Anheuser Busch	Anheuser Busch Jacksonville	153
Gilman Building Products	Gilman Building Products Union	147
Gilman Building Products	Gilman Building Products Clay	139
West Fraser Inc.	Whitehouse Lumber Duval	107
CMC Steel Fabricators	CMC Joist & Deck Bradford	101
ADAGE Hamilton	**ADAGE (proposed)**	**56**

Table 18 - Largest Sources of NO_X Nearest to the Project

Owner	Site Name	TPY
Jacksonville Electric Authority	Northside/St. Johns River Power Park	20,482
Gainesville Regional Utilities	Deerhaven Generating Station	3,541
Rayonier Performance Fibers	Fernandina Sulfite Mill	2,180
Smurfit Stone Container	Fernandina Mill	2,100
Cedar Bay	Cedar Bay Cogen	1,890
Buckeye	Buckeye Taylor	1,488
FL Gas Transmission Company	Bradford County Station	831
Suwannee American Cement	Suwannee American Cement	683
Progress Energy	Suwannee River Plant	653
Florida Rock Industries	Thomas S. Baker Cement Plant	642
FL Gas Transmission Company	Perry Compressor Station	569
City of Tallahassee	Arvah Hopkins Power Plant	284
ADAGE Hamilton	**ADAGE (proposed)**	**236**
Millennium Specialty Chemicals	Jacksonville Plant	106

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

7.3 Regional Ambient Air Quality Monitoring

The Department and Duval County Local Program operate more than twenty-five monitors at eighteen sites measuring nitrogen oxides (NO_2), SO_2, CO, PM_{10}, $PM_{2.5}$ and ozone (O_3). The 2008 monitoring network is shown in the figure below.

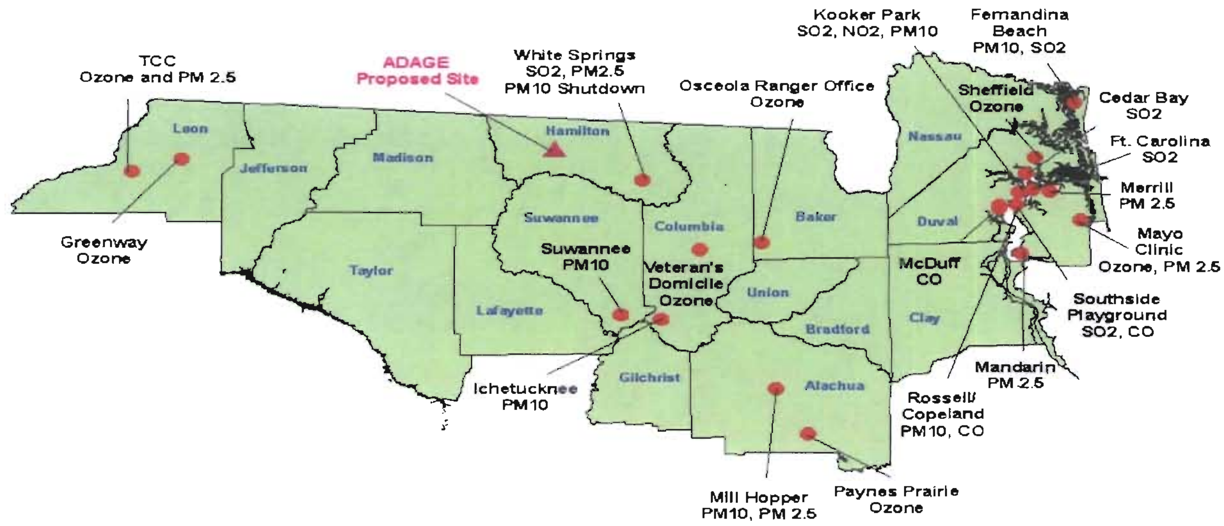

Figure 9 - Ambient Air Monitoring Stations nearest to the Project Location.

As summarized in Table 19 below, all monitors nearest to the project site presently demonstrate attainment with the AAQS.

7.4 Project Ambient Air Quality Impact Analysis

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

A combination of fence line, and non-fence line receptors were chosen for predicting maximum concentrations in the vicinity of the project. The receptor grid consisted of receptors spaced at 50 meter (m) intervals around the facility fence line. The remaining receptors were spaced at 100m intervals from the property boundary out to approximately 1 km, 200m spacing from 1km to 2km, 500m spacing from 2 km to 7 km, and 1000m spacing from 7 km to 12 km.

Models and Meteorological Data Used in the Ambient Air Quality Analysis

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

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

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

Table 19 - Ambient Air Quality Nearest to Project Site (2008).

Pollutant	Location	Averaging Period	Ambient Concentration				
			High	2nd High	Mean	Standard	Units [a]
PM_{10}	White Springs [i]	24-hour	107	94		150 [b]	μg/m³
		Annual			27 [j]	50 [c]	μg/m³
PM_{10}	Suwannee	24-hour	62	62		150 [b]	μg/m³
		Annual			21	50 [c]	μg/m³
PM_{10}	Ichetucknee	24-hour	52	50		150 [b]	μg/m³
		Annual			22	50 [c]	μg/m³
$PM_{2.5}$	Mill Hopper	24-hour	16	14		35 [d]	μg/m³
		Annual			7 [j]	15 [e]	μg/m³
$PM_{2.5}$	White Springs [h]	24-hour	24	24		35 [d]	μg/m³
		Annual			10	15 [e]	μg/m³
SO_2	White Springs	3-hour	103	20		500 [f]	ppb
		24-hour	15	8		100 [f]	ppb
		Annual			2	20 [c]	ppb
NO_2	Kooker Park	Annual			9	53 [c]	ppb
CO	Copeland	1-hour	2	2		35 [f]	ppm
		8-hour	1	1		9 [f]	ppm
Ozone	Columbia	8-hour	70	69		75 [g]	ppb
		4th highest high	67			75 [g]	ppb

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 24-hour concentrations.
e. Three year average of the weighted annual mean.
f. Not to be exceeded more than once per year.
g. Three year average of the 4th highest daily maximum.
h. Not a regulatory monitor.
i. No longer operating, data from 2007.
j. Incomplete data for regulatory purposes.

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

AAQS Analysis

For pollutants subject to an AAQS review, the total impact on ambient air quality is obtained by adding a "background" concentration to the maximum modeled concentration. This "background" concentration takes into account all sources of a particular pollutant that are not explicitly modeled. The maximum predicted annual and high, second high short term impacts for the AAQS analysis are summarized in Table 20 below. As shown in this table, emissions from the proposed facility are not expected to significantly cause or contribute to a violation of an AAQS.

Table 20 - Ambient Air Quality Impacts

Pollutant	Averaging Time	Major Sources Impact ($\mu g/m^3$)	Background Conc. 2003- 2007 ($\mu g/m^3$)	Total Impact ($\mu g/m^3$)	Total Impact Greater Than AAQS?	Florida AAQS ($\mu g/m^3$)
PM_{10}	24-hour	29	75	104	NO	150
	Annual	5	27	32	NO	50
NO_2	Annual	1	23	24	NO	100
SO_2	3-hour	67	81	148	NO	1,300
	24-hour	26	34	60	NO	260
	Annual	3	5	8	NO	60
CO	1-hour	586	4,123	4,709	NO	40,000
	8-hour	263	2176	2,439	NO	10,000

The results of the Ambient Air Quality Analysis show that the proposed project will not cause or contribute to a violation of an AAQS. Specifically, the pollutant nearest to the AAQS had a 24-hour high, second-high of 29 $\mu g/m^3$. This value occurs on the property boundary near the facility roadway. The facility road contributes to approximately 80% of the maximum 24-hour PM_{10} impact at this receptor. Therefore, it can be concluded that the truck traffic is the main contributor to the PM_{10} impact from this facility and that the concentrations of PM_{10} will decrease significantly with distance away from the proposed property. In particular, the concentrations drop by approximately 50% at 850 feet from the property line.

8. CONCLUSION

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

REVISED DRAFT PERMIT

PERMITTEE

ADAGE Hamilton, LLC
225 Wilmington West Chester Pike, Suite 302
Chadds Ford, Pennsylvania 19317

Air Permit No. 0470016-001-AC
Expires: December 31, 2013
Woody Biomass Power Plant

Authorized Representative:
Mr. Francis Reed Wills, President

Facility ID No. 0470016
55.5 Megawatt Power Plant

PROJECT

This is the final air construction permit, which authorizes construction of a 55.5 megawatt (MW, net) power plant fueled by clean woody biomass. The facility is an electrical services plant categorized under Standard Industrial Classification No. 4911. The new plant will be located in Hamilton County at the intersection of State Road 6 and County Road 146, immediately west of Interstate Highway 75 and approximately 7.5 miles west of Jasper, Florida. The UTM coordinates are Zone 17; 301.650 kilometers (km) East and 3,377.350 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. As noted in the Final Determination provided with this final permit, only minor changes and clarifications were made to the draft 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. 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

Joseph Kahn, 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.

Francis Reed Wills, ADAGE: reed.wills@duke-energy.com
David Cibik, P.E., Malcolm Pirnie: dcibik@pirnie.com
Christopher Kirts, P.E., DEP Northwest District Office: christopher.kirts@dep.state.fl.us
Kathleen Forney, EPA Region 4: forney.kathleen@epamail.epa.gov
Heather Abrams, EPA Region 4: abrams.heather@epa.gov
Betty Johnson: bettyjohnson@shareinet.net
David Wiles: rprtcard@bellsouth.net
Joy Towles Ezell: hopeforcleanwater@yahoo.com
Danny Johnson, Hamilton County Coordinator: hamiltoncounty@alltel.net
Ron Stewart, Florida Pulp and Paper Association: rstewart@fppaea.org
Vickie Gibson, DEP BAR Reading File: victoria.gibson@dep.state.fl.us

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to Section 120.52(7), Florida Statutes, with the designated agency clerk, receipt of which is hereby acknowledged.

______________________________ (Clerk) __________ (Date)

PROPOSED PROJECT

The project is the construction of a 55.5 MW (net) electric power plant utilizing a steam generating unit with bubbling fluidized bed (BFB) boiler and fueled primarily by clean woody biomass. The BFB boiler will provide steam to a steam turbine generator (STG). The new plant will be located in Hamilton County at the intersection of State Road 6 and County Road 146, immediately west of Interstate Highway 75 and approximately 7.5 miles west of Jasper, Florida.

The BFB biomass boiler will use natural gas (NG) or propane as a startup and shutdown fuel and for flame (bed) stabilization. Ultralow sulfur distillate (ULSD) fuel oil (FO) with a maximum sulfur concentration of 0.0015 percent (%) by weight can also be used as a startup and shutdown fuel and for flame (bed) stabilization.

The project will incorporate the following pollution control equipment and measures:

- Efficient combustion of woody biomass in the BFB to minimize formation of particulate matter ($PM/PM_{10}/PM_{2.5}$), nitrogen oxides (NO_X), carbon monoxide (CO) and volatile organic compounds (VOC);
- Limitation of biomass to woody untreated biomass to minimize sulfur dioxide (SO_2) and hazardous air pollutant (HAP) formation, including hydrogen chloride (HCl);
- Use of inherently clean fossil fuels for startup, shutdown and flame (bed) stabilization;
- Ammonia (NH_3) injection into selective catalytic reduction (SCR) reactor to destroy NO_X;
- Alkaline properties of the fly ash and in-duct sorbent injection system (IDSIS) to control SO_2 and HCl;
- A fabric filter baghouse to further control $PM/PM_{10}/PM_{2.5}$ and to remove sorbents; and,
- Reasonable precautions and best management practices will be employed to minimize emissions from biomass handling, storage and processing and ash (bottom and fly) handling, storage and shipment.

The project will incorporate the following emission measurement systems:

- Continuous emission monitoring systems (CEMS) for CO, SO_2, NO_X and HCl; and
- A continuous opacity monitoring system (COMS) for visible emissions (VE).

This project will consist of the following emissions units (EU).

Facility ID No. 0470016	
EU ID No.	**Emission Unit Description**
001	Feedstock delivery, handling and preparation
002	Woody biomass-fueled BFB boiler with a maximum heat input capacity of 834 mmBtu per hour
003	Ash handling, storage and shipment
004	2,200 horsepower (hp) emergency generator
005	500 hp emergency fire pump
006	500 hp emergency boiler coolant pump

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 Clean Air Act.

1. Permitting Authority: The Permitting Authority for this project is the Bureau of Air Regulation in the Division of Air Resource Management of the Department. The mailing address for the Bureau of Air Regulation is 2600 Blair Stone Road, MS #5505, Tallahassee, Florida 32399-2400. All documents related to applications for permits shall be submitted to the Air Resource Section of the Department's Northeast District Office at: 7825 Baymeadows Way, Suite 200 B, Jacksonville, Florida 32256-7590.

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 Northeast District Office at: 7825 Baymeadows Way, Suite 200 B, Jacksonville, Florida 32256-7590.

3. Appendices: The following Appendices are attached as a part of this permit and the permittee must comply with the requirement of the appendices:

Appendix BMP	Best Management Practices Plan;
Appendix CC	Common Conditions;
Appendix CEMS	Continuous Emissions Monitoring System (CEMS) Requirements;
Appendix CF	Citation Formats and Glossary of Common Terms;
Appendix CTR	Common Testing Requirements;
Appendix Db	NSPS, 40 CFR 60, Subpart Db – Standards of Performance Small Industrial-Commercial-Institutional Steam Generating Units;
Appendix F	40 CFR 75, Appendix F, Section 5 - Measurement of Boiler Heat Input Rate;
Appendix GC	General Conditions;
Appendix GP	Identification of General Provisions - NSPS 40 CFR 60, Subpart A from and NESHAP 40 CFR 63, Subpart A;
Appendix IIII	NSPS, Subpart IIII - Stationary Compression Ignition Internal Combustion Engines; and
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: No emissions unit shall be constructed or 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. Title V Permit: This permit authorizes specific modifications and/or new construction on the affected emissions units as well as initial operation to determine compliance with conditions of this permit. A Title V operation permit is required for regular operation of the permitted emissions unit. The permittee shall apply for a Title V operation permit at least 90 days prior to expiration of this permit, but no later than 180 days after completing the required work and 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.]

{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. Title IV Permit: At least 24 months before the date on which the new unit begins serving an electrical generator greater than 25 MW, the permittee shall submit an application for a Title IV Acid Rain Permit to the Department's Bureau of Air Regulation in Tallahassee and a copy to the Region 4 Office of the U.S. Environmental Protection Agency (EPA) in Atlanta, Georgia. This permit does not specify the Acid Rain program requirements. These will be included in the Title V air operation permit. [40 CFR 72].

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 ADAGE facility to control fugitive PM emissions. General 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.]

A. Biomass Receiving, Handling, Storage and Processing (EU-001)

This section of the permit addresses the following emissions unit.

EU ID No. 001	Emission Unit Description
Biomass receiving, handling, storage and processing: The biomass receiving, handling, storage and processing area will consist of unloading, transferring, storage and delivery of clean woody biomass to the BFB boiler. This emission unit is being designed to accommodate clean woody biomass primarily in the form of pre-processed chips. The clean woody biomass will be brought to the site in covered trucks. The trucks will enter the plant and will proceed to a scale station for weighing. The trucks will then proceed to the truck dumping stations where the contents (i.e. chipped biomass) from the trucks will be emptied into receiving hoppers, as well as receiving hoppers that can be accessed by material handling equipment. Typical operation of the fuel receiving system will be 12 hours/day and 5 days/week. The fuel handling system will operate 24 hours a day and 7 days a week. Other design characteristic are as follows: • Clean Woody Biomass Feedstock Throughput: 600 tons per hour (TPH); • Truck Dumper Rates: Three at 500 TPH and 4,047,120 TPY. One at 250 TPH and 2,023,560 TPY; • Intermediate Conveyors*: 500 TPH and 4,047,120 TPY; and • Silo Supply Conveyor and Fuel Silos Bins #1 and 2: 150 TPH and 1,156,320 TPY. * Secondary Processing Conveyor, Primary and Secondary Coarse Screen Supply Conveyor, Fine Screen Conveyor, Outdoor Storage Conveyor.	

EQUIPMENT

1. Equipment: The permittee is authorized to construct Emission Unit EU-001, which consists of Fuel Receiving, Handling, Storage and Processing systems containing the following equipment classified as potential sources of $PM/PM_{10}/PM_{2.5}$ emissions hence forth called PM:
   a. Truck Dumper Areas: Truck Dumpers #1 – 3 and two (2) Self-Dumping Stations;
   b. Enclosed Conveyor Systems: Enclosed Conveyor Systems for woody biomass handling. Associated drop points within the conveyor system shall be enclosed where technically feasible.
   c. Woody Biomass Storage Areas: Associated drop points from conveyor system to storage areas shall be designed to minimize fugitive PM emissions; and,
   d. Boiler Delivery Bins: Fuel Bins #1 and 2 shall be constructed with vent screens to control PM emissions.

   [Application No. 0470016-001-AC; and Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

2. Air Pollution Control Equipment: To minimize fugitive PM, woody biomass conveyors shall be enclosed. Dust collectors shall be installed on the conveyor transfer drop points. Vent screens associated with the fuel bins shall be installed on the fuel bins to minimize PM emissions.

   {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. However, the bottom of the conveyance belt shall be accessible for maintenance and repairs.}

   *{Permitting Note: One small section of the conveyance belt of the conveyors near the receiving point shall provide for visible inspection from above so that woody biomass that does not meet **Condition 5** of this subsection can be removed.}*

   [Application No. 0470016-001-AC and Rule 62-4.070, F.A.C. Reasonable Assurance]

3. 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 ADGAE facility meet the requirements given in **Condition 5** of this subsection. No later than 180 days before the ADAGE facility 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 incorporate into the Title V operating permit.

   {Permitting Note: As part of that final BMP, technical information may be provided by ADAGE Hamilton LLC to the Compliance Authority based on the final engineering of the fuel conveyance system that describes methods or equipment designed to control fugitive PM emissions from the conveyor transfer drop points. These methodologies and equipment designs may obviate the requirement to install dust collectors on the conveyor transfer drop points stipulated in ***Condition 2*** *of this subsection. Acceptance of the final BMP by the Compliance Authority with the reference to the specific design of the conveyor transfer drop points may satisfy the requirement to install dust collectors.}*

   {Permitting Note: PM emissions from this emission unit during operation of the ADAGE facility are estimated to be 43.4 tons in any consecutive twelve month period of this amount 24 tons are from traffic on paved roadways.}

   [Application No. 0470016-001-AC; Rule 62-4.070, F.A.C. Reasonable Assurance, and Rule 62-296.320, F.A.C.]

PERFORMANCE RESTRICTIONS

4. Hours of Operation: The hours of operation of this emissions unit is not limited (i.e., unrestricted at 8,760 hours per year).
   [Application No. 0470016-001-AC and Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

5. Clean Woody Biomass: The fuel to be received, handled, stored and processed shall consist of clean, untreated woody biomass as defined below. The BMP plan referenced in **Condition 3** of this subsection shall be followed.

Fuel Group	**Description**
Field residuals and slash	Tops, limbs and whole tree soft or hardwoods that result from harvest and/or thinning as well as the residue therefrom
Understory	Forest understory including smaller trees and saplings
Land clearing and storm debris	Tree parts and/or branches that have been cut down for land development or line clearing purposes or that have been gathered after storms.
Production residuals	Butts, sticks, pole ends and tree surgeon material
Saw mill waste	Saw dust and kerf waste from cutting/milling whole green trees
Planer mill shavings	Fines from planing kiln-dried lumber
Source separated construction wood waste	Clean construction wood waste that was a primary mill product and has not been treated in any way such as pallets, dimensional lumber, clean wood trim, clean milled lumber

[Application No. 0470016-001-AC and Rule 62-4.070(3), F.A.C. Reasonable Assurance]

6. Clean Woody Biomass Storage Areas: Primary (chipped woody biomass) and secondary (wood chips from storm damage) will be placed in two separate storage piles. The primary pile will be approximately 6,000,000 ft^3 in size while the secondary pile will be approximately 3,000,000 ft^3 in size. Woody biomass will be placed in the piles which will be largely managed by mechanical means such as front-end loaders. The biomass will then taken by covered conveyors to the biomass storage silos and from there to the BFB boiler. Each storage pile area will be on level, firm ground. [Application No. 0470016-001-AC]

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

EMISSIONS STANDARDS

8. Opacity: As determined by EPA Method 9, there shall be no visible emissions 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 dust collectors associated with this emission unit. [Application No. 0470016-001-AC and Rule 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. 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. [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
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 GP of this permit 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

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 units.

EU ID No. 002	Emission Unit Description
Description: The boiler will be a woody biomass-fueled bubbling fluidized bed (BFB) boiler wherein wood is combusted within in a bed of hot sand. The heat from the exhaust will be recovered to generate superheated steam to generate 55.5 MW (net) of electricity in a STG. *Fuels*: The primary fuel will be clean woody biomass as described in **subsection 3-A, Condition 5 and Appendix BMP** of this permit. Natural gas, propane or ULSD FO with a sulfur content less than 0.0015% sulfur (S) will be use for startup, shutdown and combustion (bed) stabilization. *Capacity*: The maximum heat input capacity is 834 mmBtu per hour (4-hour average). The steam production capability will be between 354,000 to 570,000 pounds per hour (lb/hr). The maximum heat input capacity using fossil fuels is 240 mmBtu/hr. *Controls*: Efficient combustion of woody biomass in the BFB boiler to minimize formation of PM, NO_X, CO and VOC; limitation of biomass to woody untreated biomass to minimize SO_2 and HAP formation, including HCl; use of inherently clean fossil fuels for startup, shutdown and flame (bed) stabilization; NH_3 injection into SCR reactor to destroy NO_X; a IDSIS to further control SO_2 and HCl; and a fabric filter baghouse with a design efficiency of 99.9% to further control PM and VE, (i.e. opacity). *Stack Parameters*: The stack will be approximately 12.0 feet in diameter (maximum) and 195 feet tall (minimum). Exhaust flue gas will exit the stack at the following approximate conditions: an exit temperature of 320° F and a volumetric flow rate of between 246,900 to 306,400 actual cubic feet per minute (acfm). *Continuous emissions and opacity monitoring systems (CEMS, COMS)*: Emissions of CO, NO_X, SO_2, and HCl will be monitored and recorded by CEMS. VE will be monitored and recorded by a COMS. *Applicability of 40 CFR Subpart Db (NSPS Subpart Db)*: This unit is subject to NSPS Subpart Db - Industrial-Commercial-Institutional Steam Generating Units because it has a maximum heat input capacity greater than 100 mmBtu/hr from the fuels combusted and is not subject to NSPS Subpart Da because it has a maximum heat input capacity less than 250 mmBtu/hr from the fossil fuels combusted.	

EQUIPMENT

1. Construction of BFB Boiler: The permittee is authorized to construct a BFB boiler with fluidizing air supply, fossil fuel startup and stabilization burners, overfire air ports, steam drum, superheater, economizer, air heater, ash hoppers, ducts, steam turbine-electrical generator, fuel feeding equipment, air-cooled condensing unit, air pollution control equipment and other associated equipment. [Application No. 0470016-001-AC]
2. Air Pollution Control Equipment: To comply with the emission standards of this permit, the permittee shall install the following add-on air pollution control equipment on the BFB boiler.
   a. Fabric Filter Baghouse: The permittee shall design, install, operate and maintain a fabric baghouse to control PM and VE. The control efficiency of the baghouse shall be 99.9% as demonstrated by an emission rate of 0.01 grains per dry standard cubic feet (gr/dscf) at 7% oxygen (O_2) at its outlet (filterable PM only).

b. SCR System: The permittee shall design, install, operate, and maintain an NH_3-based SCR system including reagent storage tank, pumps, metering system, injection grid, reactor and catalyst to reduce NO_X emissions in the flue gas exhaust and achieve the NO_X emissions standards specified in this subsection. The SCR shall be brought on line and functioning properly whenever the boiler is in operation in accordance with the manufacturer's procedures and guidelines.

c. IDSIS: An IDSIS including a baghouse, sorbent storage silo, pumps, metering and injection equipment shall be installed to control HCl and SO_2 emissions to the emission standards specified in this section. As part of this IDSIS, the sorbent silo will be equipped with a vent filter to control PM emissions. The IDSIS will rely on the presence of alkaline fly ash and be augmented as necessary by the use of injected lime, trona, or sodium bicarbonate sorbent. The HCl and SO_2 CEMS output data expressed in lbs/hr averaged over a 24 hour period shall be reviewed by trained plant personnel on a daily and monthly basis to determine required operation of, or adjustment to the sorbent injection augmentation to ensure the HCl and SO_2 emission standards will be maintained. HCl and SO_2 emissions data shall be reported to the Department on a quarterly basis.

{Permitting note: Sorbent injection augmentation is not continuously required if compliance with the HCl and SO_2 emission standards is established by the CEMS output data.}

[Application No. 0470016-001-AC; NSPS Subpart Db; and Rule 62-4.070(3), F.A.C.]

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

3. ULSD FO Storage Tank: The permittee is authorized to construct a 50,000 gallon tank to store ULSD FO for use as a BFB biomass boiler fuel for startup, shutdown and flame (bed) stabilization. [Applicant request and 62-4.070(3), Reasonable Assurance]

{Permitting Note: The ULSD FO storage tank at the ADAGE facility is not subject to NSPS Subpart Kb because it is larger or equal to 40,000 gallons (151 cubic meters) and stores a liquid (ULSD FO) with a maximum true vapor pressure less than 3.5 kPa (0.51 pounds per square inch (psi)). Accordingly it is and unregulated emissions unit.}
[40 CFR 60.110b(a) and (c); Rule 62-204.800(7)(b), F.A.C.]

PERFORMANCE REQUIREMENTS

4. Authorized Fuels: The steam generating unit is authorized to combust as its primary fuel clean woody biomass as defined in **Condition 5 of subsection 3-A** of this permit. In addition, the boiler is authorized to combust natural gas as a supplemental fuel primarily for startup, shutdown and flame (bed) combustion stabilization. The boiler is also authorized to combust ULSD FO or propane for startup, shutdown and flame (bed) combustion stabilization. As per **Condition 6** below, the burner equipment to fire fossil fuels in the BFB biomass boiler will not have the physical capabilities to burn more than 250 mmBtu/hr of fossil fuel heat input consisting of NG, ULSD FO or propane to satisfy the heat input limitation requirements of NSPS, Subpart Db.

{Restriction of fossil fuels to ULSD FO, natural gas or propane satisfies the requirement to determine BACT for PM and SO_2 to the extent that fossil fuel is fired in accordance with Rule 62-296.410, F.A.C. for this class of boiler.}

[Application No. 0470016-001-AC; Rules 62-4.070(3), 62-296.410, 62-210.200(PTE), F.A.C., and NSPS, Subpart Db]

5. Heat Input Rate from all Fuels: The maximum heat input capacity from all fuel combinations is 834 mmBtu per hour (4-hour average). [Application No. 0470016-001-AC; NSPS Subpart Db; Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

6. Heat Input from Fossil Fuels: The maximum heat input capacity to combust all fossil fuels (ULSD FO, NG and propane) on a steady state basis, as determined by the physical design and characteristics of the boiler is limited to 240 mmBtu/hr. [Application No. 0470016-001-AC; NSPS Subpart Db; Rules 62-4.070(3); and 62-210.200(PTE), F.A.C.]

7. Operational Hours: The hours of operation of this emission unit are not restricted (8760 hours/year). [Application No. 0470016-001-AC; Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

EMISSIONS STANDARDS

8. Emission Limits: Emissions from BFB boiler shall not exceed the following standards:

Pollutant	Initial (I) or Annual (A) Test	CEMS/COMS Based Averages	
NO_X [a]	53.1 lb/hr (I)	53.1 lb/hr 12-month, rolled monthly	0.20 lb/mmBtu 30-day rolling average
SO_2 [b]	34.1 lb/hr (I)	34.1 lb/hr, 12-month average, rolled monthly	
CO [c]	56.0 lb/hr (I)	56.0 lb/hr, 12-month average, rolled monthly	
HCl [d]	2.22 lb/hr (I)	9.7 tons per year, 12-month average, rolled monthly	
PM/PM_{10} [e, f]	22.0 lb/hr (I,A) 0.029 lb/mmBtu (I,A) 0.01 gr/dscf @7% O_2	10 percent (%) opacity (6-minute blocks) 20% opacity (one 6-minute block per hour)	
THC [g]	(I)	Not applicable	
NH_3 Slip [h]	10 ppmvd @ 7% O_2 (I,A)	Not applicable	

a. NO_X limit in pounds per million Btu heat input (lb/mmBtu) is pursuant to NSPS Subpart Db. Mass rate limit in pounds per hour insures annual emissions will be less than 250 tons per year (TPY).
b. Use of low sulfur fuels including wood, ULSD FO, natural gas and propane insure that uncontrolled SO_2 emissions are less than 0.32 lb/mmBtu. Therefore no specific limit from NSPS Subpart Db applies. Mass rate limit in lb/hr insures annual emissions will be less than 250 TPY.
c. Mass rate CO emission limit insures annual emissions will be less than 250 TPY.
d. Mass rate HCl emission limit insures annual emissions will be less than 10 TPY.
e. Standard includes filterable and condensable PM/PM_{10}. Compliance with the PM/PM_{10} mass emission limit insures compliance with the 40 CFR 60, Subpart Db limit of 0.030 lb PM/mmBtu (filterable PM). Mass rate limit in lb/hr insures annual emissions will be less than 250 TPY.
f. During startups, shutdowns and malfunction the following limits apply: 20% opacity (6-minute blocks) except for one 6-minute block per hour of 27%.
g. Total hydrocarbon (THC) as a surrogate for VOC. One initial test required to verify emission rate.
h. Ammonia (NH_3) slip in parts per million by dry volume at 7% oxygen (ppmvd @ 7% O_2).

[Applicant requests; Rules 62-210.200(PTE), 62-296.406, 62-296.410, and 62-4.070(3)(Reasonable Assurance), F.A.C. to avoid triggering PSD Requirements under Rule 62-212.400, F.A.C.; 40 CFR 60, Subpart Db]

9. Sorbent Storage Silo VE: Opacity from the vent filter of the sorbent storage silo shall not exceed 5% opacity based on EPA Method 9 during initial and annual tests.

CONTINUOUS EMISSION MONITORS

10. Continuous Monitoring Requirements: The permittee shall install, calibrate, maintain and operate CEMS, a COMS and a diluent monitor to measure and record the emissions of SO_2, opacity, NO_X, CO and HCl from the boiler stack in a manner sufficient to demonstrate continuous compliance with the CEMS-based and COMS-based emission standards in **Conditions 8** above. Each CEMS and COMS 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 SO_2, NO_X, CO or HCl standard (and subject to the specified averaging period), the permittee shall notify the Compliance Authority.

    a. SO_2 CEMS: - The SO_2 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.

    b. NO_X CEMS: The NO_X CEMS shall be certified, operated, and maintained in accordance with the requirements of 40 CFR Part 75. Recordkeeping and reporting shall be conducted pursuant to Subpart Db in 40 CFR 60 and Subparts F and G in 40 CFR 75.

    c. 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. The CO monitor span values shall be set appropriately, considering the allowable methods of operation and corresponding emission standards.

    d. HCl CEMS: The HCl CEMS shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 15, EPA Method OTM 22 or alternative specifications approved by the Department. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, EPA Method OTM 23 or alternative procedures approved by the Department. A Data Assessment Report shall be made each calendar quarter and reported semiannually to the Compliance Authority. The RATA tests required for the HCl monitor shall be performed using EPA Method 26 or 26A as detailed in Appendix A of 40 CFR 60 or by Method 320 as detailed in Appendix A of 40 CFR 63. The HCl monitor span values shall be set appropriately, considering the allowable methods of operation and corresponding emission standards. Approval of specific initial performance specifications and quality assurance and control (Q&A) procedures must be provided by the Department prior to installation and operation of the CEM system.

    e. 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 steam generating unit. The COMS shall be certified pursuant to 40 CFR 60 Appendix B, Performance Specification 1.

    f. Diluent Monitor: The oxygen (O_2) or carbon dioxide (CO_2) content of the flue gas shall be monitored at the location where CO and NO_X are monitored. Each monitor shall comply with the performance and quality assurance requirements of 40 CFR 75.

    [Application No. 0470016-001-AC; Rule 62-4.070(3), F.A.C.; 40 CFR 60, Subpart Db and Appendices]

STARTUP, SHUTDOWN, AND MALFUNCTION REQUIREMENTS

11. Malfunction Notifications: In case of excess emissions resulting from malfunctions, each owner or operator shall notify the Compliance Authority. If the permittee is temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by hazard of fire, wind or by other cause, the permittee shall immediately (within one working day) notify the Compliance Authority. Notification shall include pertinent information as to the cause of the problem, and what steps are being taken to correct the problem and to prevent its 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 Department rules. If requested by the Compliance Authority, the owner or operator shall submit a quarterly written report describing the malfunction. [Rules 62-210.700(6) and 62-4.130, F.A.C.]

12. Operating Procedures: The emission standards established by this permit rely on "good combustion practices" to reduce emissions. Therefore, all operators and supervisors shall be properly trained to operate and maintain the steam generating unit and pollution control systems in accordance with the guidelines and procedures established by each manufacturer. The training shall include good combustion practices as well as methods of minimizing excess emissions. [Rule 62-4.070(3), F.A.C.]

13. 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.

14. Emission Limit Compliance and Excess Emission: Because of the long-term nature of all of the NO_X, SO_2, CO and HCl mass emission rate limits and to avoid triggering PSD, all emissions data for these pollutants, including periods of startup, shutdown and malfunction, shall be included in any compliance determinations based on CEMS data.
[Rules 62-210.700(4), 62-210.200(PTE) and 62-4.070(3), F.A.C.]

15. Excess Emissions Allowed – Opacity Requirements: 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. Opacity: During startup, shutdown and malfunctions, the stack opacity shall not exceed 20% based on 6-minute block averages, except for one 6-minute block per hour that shall not exceed 27% opacity.

    [Rules 62-210.700(5), 62-210.200(PTE) and 62-4.070(3), F.A.C.]

TESTING REQUIREMENTS

16. Boiler Heat Input Rate Calculation: Section 5 of Appendix F of 40 CFR 75 provides a methodology for calculation of the heat input rate to a boiler using F-Factors. The applicable portions of 40 CFR 75 for the calculation of the heat input rate to the biomass BFB boiler at the ADAGE facility is contained in Appendix F of this permit. This procedure shall be used to calculate the heat input rate in mmBtu/hr to the BFB boiler when using clean woody biomass as its primary fuel and NG, ULSD FO or propane as a startup, shutdown and flame (bed) stabilization fuel.
[Rule 62-4.070(3), F.A.C. Reasonable Assurance]

17. Initial and Annual Stack Tests: In accordance with test methods specified in this permit, the BFB boiler stack shall be tested to demonstrate initial compliance with the emission standards for NH_3, CO, NO_X, PM, SO_2, THC, opacity (boiler and vent filter of sorbent storage silo) and HCl. The tests shall be conducted within 60 days after achieving the maximum heat input rate to the boiler, but not later than 180 days after the initial startup of the boiler. Subsequent compliance stack tests for NH_3 slip, PM and opacity (vent filter stack of sorbent storage silo) shall also be conducted during each federal fiscal year (October 1st to September 30th). Tests shall be conducted between 90 and 100% of the maximum heat input rate when firing only the primary fuels. CEMS data for CO, NO_X, SO_2 and

HCl along with COMS data for opacity shall be reported for each run of the required tests for NH_3 and PM. The Department may require the permittee to repeat some or all of these initial stack tests after major replacement or major repair of any air pollution control or process equipment. [Rules 62-212.400(5)(c) and 62-297.310(7)(a) and (b), F.A.C.; 40 CFR 60.8]

{Permitting Note: All initial tests must be conducted between 90% and 100% of permitted capacity; otherwise, this permit will be modified to reflect the true maximum capacity as constructed.}

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

EPA Method	Description of Method and Comments
CTM-027 or 320	Measurement of NH_3 Slip *or* Measurement of Vapor Phase Organic and Inorganic Emissions by Extractive Fourier Transform Infrared (FTIR) Spectroscopy
1 - 4	Determination of Traverse Points, Velocity and Flow Rate, Gas Analysis, and Moisture Content *{Notes: Methods shall be performed as necessary to support other methods.}*
5, 5B, 17	Measurement of PM
6C	Measurement of SO_2 Emissions (Instrumental)
7E	Measurement of NO_X Emissions (Instrumental)
9	Visual Determination of the Opacity
10	Measurement of CO Emissions (Instrumental) *{Note: The method shall be based on a continuous sampling train.}*
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.}*
15	Determination of Hydrogen Sulfide, Carbonyl Sulfide and Carbon Disulfide Emissions from Stationary Sources
19	Calculation Method for NO_X, PM, and SO_2 Emission Rates
25	Determination of Total Gaseous Nonmethane Organic Emissions as Carbon
25A	Measurement of Gaseous Organic Concentrations (Flame Ionization)
26, 26A	Determination of HCl Emissions from Stationary Sources
201, 201A, 202	Measurement of PM_{10} and Condensable PM

Method CTM-027 is published on EPA's Technology Transfer Network Web Site at http://www.epa.gov/ttn/emc/ctm.html . The other methods are specified in Appendix A of 40 CFR 60, adopted by reference in Rule 62-204.800, F.A.C.

[Rules 62-204.800, F.A.C. and 40 CFR 60, Appendix A]

19. Required CEMS/COMS: The permittee shall install, calibrate, certify, operate and maintain CEMS and COMS on the BFB biomass boiler stack to demonstrate compliance with the SO_2, NO_X, CO and HCl emissions standards in **Condition 8** of this subsection. The permittee shall comply with the CEMS requirements specified in Appendix CEMS of this permit. [Rule 62-4.070(3), F.A.C.]

OTHER MONITORING REQUIREMENTS

20. Steam Parameters: In accordance with the manufacturer's recommendations, the permittee shall install, calibrate, operate and maintain continuous monitoring and recording devices for the following parameters: steam temperature (°F), steam pressure (psig) and steam production rate (lb/hour). Records shall be maintained on site and made available upon request.
[Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

21. 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 steam generating unit. Records shall be maintained on site and made available upon request. [Rule 62-4.070(3), F.A.C.]

22. Bag Leak Detection: The permittee shall maintain continuous operation of bag leak detection systems on the steam generating unit 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.].

23. SCR 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 SCR system for the steam generating unit. The permittee shall document the general range of NH_3 flow rates required to meet the NO_X standard 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.]

RECORDS AND REPORTS

24. Stack Test Reports: In addition to the information required in Rule 62-297.310(8), F.A.C., each stack test report shall also include the following information: steam production rate (lb/hour), heat input rate (mmBtu/hour), calculated authorized fuels firing rate (tons/hour, cubic feet per minute or gallons per hour as appropriate), and emission rates (ammonia (NH_3) slip in ppmvd @ 7% oxygen; PM, VOC, NO_X, SO_2, and CO and HCl in lb/hr). [Rule 62-4.070(3), F.A.C.]

25. Monthly Operations Summary: By the tenth calendar day of each month, the permittee shall record the following for each fuel used in the BFB biomass boiler in a written or electronic log for the previous month of operation: hours of operation, tons of clean woody biomass, cubic feet of natural gas, cubic feet of propane, or gallons of ULSD FO; pounds of steam per month; total heat input rate; and the updated 12-month rolling totals for each of these operating parameters. In addition, the hourly heat input rate to the BFB biomass boiler shall be recorded and reported. The Monthly Operations Summary shall be maintained on site and made available for inspection when requested by the Department. [Rules 62-4.070(3) F.A.C. Reasonable Assurance]

26. Quarterly CO, NO_X, SO_2, HCl and Opacity Emissions Report: Within 30 days following the end of each quarter, the permittee shall submit a report to the Compliance Authority summarizing CO, NO_X, SO_2, HCl and opacity emissions including periods of startups, shutdowns, malfunctions, and CEMS and COMS systems monitor availability for the previous quarter. If opacity COMS data is excluded from a compliance determination during the quarter due to a malfunction, the permittee shall include a description of the malfunction, the actual emissions recorded, and the actions taken to correct the malfunction. See Appendix CTR of this permit for the reporting format. [Rules 62-4.070(3), 62-4.130, and 62-210.400(5)(c), F.A.C.]

C. Ash Handling, Storage and Shipment (EU-003)

This section of the permit addresses the following emissions unit.

EU ID No. 003	Emission Unit Description
Ash Handling, Storage and Shipment: The Ash Handling, Storage and Shipment emission unit shall be designed to collect fly ash from the baghouse hoppers. Fly ash will be transferred via a totally enclosed system to a fly ash storage silo which shall be equipped with a silo baghouse. The baghouse will be designed to achieve a PM emission rate of 0.01 gr/dscf. Fly ash from the storage silo will be sent to a truck loading operation for removal off-site. The only PM emission points in the system will be the ash silo and the ash loadout operation to trucks.	

EQUIPMENT

1. Equipment: The permittee is authorized to construct Emission Unit EU-003, which consists of ash (fly and bottom) handling, storage and shipment systems containing the following equipment:
   a. Fly Ash Handling: The fly ash handling system consisting of totally enclosed hoppers and drop points associated with the collection and transfer of fly ash from the baghouse used to control PM emissions from the BFB biomass boiler to a storage silo.
   b. Fly Ash Storage: A fly ash storage system consisting a storage silo and baghouse to control PM emissions.
   c. Fly Ash Shipment: The fly ash shipment system consisting of the drop points, conditioner and chutes associated with the transfer of the fly ash from the storage silo to trucks for shipment.
   d. Bottom Ash Handling and Shipment: The bottom ash handling and shipment system consisting of the hoppers, drop points, collecting conveyor and transfer conveyor associated with the collection, transfer and shipment of bottom ash from the BFB biomass boiler.

   [Application No. 0470016-001-AC]
2. Air Pollution Control Equipment: To comply with the emission standards of this permit, the permittee shall install and operate the following air pollution control equipment on the ash (fly and bottom) handling, storage and shipment emission unit.
   a. Enclosures and Dust Collectors: To minimize fugitive PM, bottom and fly ash conveyors shall be enclosed. Where practical, dust collectors shall be installed on the bottom and fly ash transfer points, drop points, hoppers and chutes.
   [Application No. 0470016-001-AC and Rule 62-4.070, F.A.C. Reasonable Assurance].
   b. Fly Ash Silo Baghouse: One shaker type or similar baghouse shall be designed, installed and maintained to remove PM from the fly ash storage silo exhaust. The baghouse shall be installed and operational before the silo becomes operational. The baghouse will be designed to achieve a PM emission rate of 0.01 gr/dscf.
   [Application No. 0470016-001-AC; Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

PERFORMANCE RESTRICTION

3. Hours of Operation: The hours of operation of this emissions unit is not limited (i.e., unrestricted at 8,760 hours per year).
4. Fly Ash Handling and Storage: The fly ash handling system shall have a maximum design transfer rate of 5.5 TPH with a maximum annual design transfer rate of 48,180 TPY.
5. Fly Ash Shipment: The fly ash shipment system shall have a maximum design transfer rate of 84 TPH with a maximum annual design transfer rate of 48,180 TPY.

6. Bottom Ash Handling: The bottom ash handling system shall have a maximum design transfer rate of 1.0 TPH with a maximum annual design transfer rate of 8,760 TPY.

7. Ash Handling, Storage and Shipment: The overall ash handling, storage and shipment system (EU-003) shall have a maximum a maximum annual design transfer rate of 56,940 TPY.
   [Application No. 0470016-001-AC and 62-210.200(PTE), F.A.C.]

EMISSIONS STANDARDS

8. VE Standard: As determined by EPA Method 9, there shall be no visible emissions greater than 10% opacity, except for one 6 minute period no greater than 20% from the bottom and fly ash conveyors, transfer points, drop points, hoppers, chutes, dust collectors and fly ash silo baghouse.
   [Rule 62-4.070, F.A.C. Reasonable Assurance and Rule 62-212.400(5)(c), F.A.C.]

9. PM Emission Standard: PM emissions from baghouse of the fly ash silo shall not exceed 0.01 gr/dscf. [Application No. 0470016-001-AC; Rules 62-4.070(3) and 62-210.200(PTE), F.A.C. and Rule 62-4.070, F.A.C. Reasonable Assurance]

10. Baghouse PM Standard by Opacity Measurement: A visible emission reading of 10% opacity or less may be used to demonstrate compliance with the PM emission standard in **Condition 9** above. A visible emission reading greater than 10% opacity will require the permittee to perform a PM emissions stack test within 60 days to show compliance with the PM standard.
    [Application No. 0470016-020-AC; Rules 62-296.603; 62-296.712, F.A.C.; and 40 CFR 60.122(a)(2) and Rule 62-4.070, F.A.C. Reasonable Assurance]

11. Best Management Practices to Control Unconfined Emissions of PM: To ensure the emission standards with regard to opacity and PM of this subsection are complied with, the procedures set forth in **Condition 11** of **Section II** of this permit, "Unconfined Emissions of Particulate Matter," shall be adhered to where practical and cost effective. In addition, the procedures set forth in Appendix BMP of this permit with regard to fugitive emissions` shall be adhered to.
    [Application No. 0470016-001-AC; Rule 62-4.070, F.A.C. Reasonable Assurance, and Rule 62-296.320 F.A.C.]

TESTING AND MONITORING REQUIREMENTS

12. Initial Compliance Tests: The bottom and fly ash conveyors, transfer points, drop points, hoppers, chutes, dust collectors and fly ash silo baghouse associated with this emission unit shall be tested to demonstrate initial compliance with the VE standards specified in **Condition 8** of this subsection. The initial test shall be conducted within 180 days after initial operation.
    [Rule 62-297.310(7)(a)1., F.A.C. and Rule 62-4.070(3), F.A.C.]

13. Annual Compliance Tests: During each federal fiscal year (October 1st to September 30th), the bottom and fly ash conveyors, transfer points, drop points, hoppers, chutes, dust collectors and fly ash silo baghouse associated with this emission unit shall be tested to demonstrate compliance with the VE emissions standards specified in **Condition 8** of this subsection.
    [Rule 62-297.310(7)(a)4, F.A.C. and Rule 62-4.070(3), F.A.C.]

14. Fly Ash Silo PM Compliance Test: The initial and annual VE tests in **Conditions 12 and 13** of this subsection with regard to the fly ash silo baghouse shall serve as a surrogate for the PM emissions tests. If the VE emissions standard in **Condition 8** of this subsection is not met for the fly ash silo baghouse, a PM test utilizing EPA Method 5 must be conducted on baghouse stack to show compliance with the PM emissions standard in **Condition 9** of this subsection within 60 days.
    [Rule 62-297.620(4), F.A.C.]

15. Bag Leak Detection: The permittee shall maintain continuous operation of bag leak detection systems, including records, on the fly ash storage silo baghouse. Baghouse leak detection records shall be kept on site and made available upon request.
[Rule 62-4.070(3), F.A.C.].

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

Method	Description of Method and Comments
EPA 5	Determination of Particulate Emissions. The minimum sample volume shall be 30 dry standard cubic feet.
EPA 9	Method 9 - Visual Determination of the Opacity of Emissions from Stationary Sources

RECORDS AND REPORTS

17. 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.]

D. Emergency Electrical Generator EU-004

This section of the permit addresses the following emissions units.

EU ID No.	Emission Unit Description
004	One emergency diesel generator with a maximum design rating of 1,800 kilowatts (kW)

NSPS AND NESHAP APPLICABILITY

1. 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]

2. 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)]

EQUIPMENT

3. Emergency Generators: The permittee is authorized to install, operate, and maintain one emergency generator with a maximum design rating of 1,800 kW (2,200 hp) or smaller.
[Application No. 0470016-001-AC and Rule 62-210.200 (PTE), F.A.C.]

PERFORMANCE RESTRICTIONS

4. Hours of Operation: The emergency generator may operate up to 250 hours per year for maintenance and testing purposes. [Application No. 0470016-001-AC and Rule 62-210.200 (PTE), F.A.C.]

5. Authorized Fuel: The emergency generator shall fire ULSD FO. The ULSD FO shall contain no more than 0.0015% sulfur by weight. [Application No. 0470016-001-AC and Rule 62-210.200 (PTE), F.A.C.]

EMISSION STANDARDS

6. 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 the language of which is given in Appendix IIII of this permit. Manufacturer certification can be provided to the Department in lieu of actual stack testing.

Emergency Generator (> 560 kW and ≤ 2237 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	6.4

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

[Application No. 0470016-001-AC and Subpart IIII and Rule 62-4.070(3), F.A.C.]

RECORDS AND REPORTS

7. 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]

E. Emergency Firewater and Boiler Coolant Pumps (EU-005 and EU-006)

This section of the permit addresses the following emissions unit.

ID	Emission Unit Description
005	One emergency diesel firewater pump engine with a maximum design rating of 500 hp
006	One emergency boiler coolant water pump engine with a maximum design rating of 500 hp

NSPS AND NESHAP APPLICABILITY

1. NSPS Subpart IIII Applicability: Each 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]

2. NESHAP Subpart ZZZZ Applicability: The emergency pump engines are 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)]

EQUIPMENT

3. Engine Driven Pumps: The permittee is authorized to install, operate, and maintain one emergency diesel fire pump engine and one emergency diesel boiler coolant water pump engine. Each pump engine will have a maximum rating of 500 hp or smaller.
[Application No. 0470016-001-AC and Rule 62-210.200(PTE), F.A.C.]

PERFORMANCE RESTRICTIONS

4. Hours of Operation: Each pump may operate up to 250 hours per year for maintenance and testing purposes. [Application No. 0470016-001-AC and Rule 62-210.200 (PTE), F.A.C.]

5. Authorized Fuel: This unit shall fire ULSD FO. The ULSD FO shall contain no more than 0.0015% sulfur by weight. [Application No. 0470016-001-AC and Rule 62-210.200 (PTE), F.A.C.]

EMISSION STANDARDS

6. Emissions Limits: The emergency fire pump and boiler coolant pump engines shall comply with the following emission limits and demonstrate compliance in accordance with the procedures given in 40 CFR 60, Subpart IIII. Manufacturer certification 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 ($\geq$ 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 ULSD FO in the emergency generator with a fuel sulfur content of 0.0015% by weight.

[Application No. 0470016-001-AC; 40 CFR 60, Subpart IIII; and Rule 62-4.070(3), F.A.C.]

RECORDS AND REPORTS

7. 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. [Rule 62-212.400 (BACT), F.A.C. and 40 CFR 60.4211]

CONTENTS

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 ADAGE 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 ADAGE facility becomes operational }

Practice	Description
Best Management Practice – Minimization of Fugitive Dust	1) Conveyor systems and associated drop points shall be enclosed or partially enclosed. 2) Drop points to woody biomass storage areas shall be designed to minimize the overall exposed (or exposed to atmosphere) drop height. 3) Periodic equipment maintenance shall be performed to maintain conveyor systems and associated drop point integrity. Appropriate plant records shall be maintained on equipment maintenance performed. 4) Fuel silos shall be equipped with vent filters. 5) Daily observations of the conveyor systems and associated drop point integrity to identify any equipment abnormalities. 6) Plant personnel shall be trained on identification of warning signs for potential equipment malfunction. 7) Signs shall be posted identifying potential warning signs of equipment malfunction. 8) Procedures shall be established for defining excessive fugitive dust from woody biomass truck unloading operations. Plant personnel shall visually observe truck unloading operations and if excessive fugitive dust is detected appropriate fugitive dust minimization techniques shall be implemented. 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 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.
Storage Pile Management	1) Woody biomass storage areas shall be managed to avoid excessive wind erosion. 2) A woody biomass fugitive dust management plan shall be developed and maintained onsite. Plan shall identify warning signs for conditions that could result in excessive fugitive dust formation. Plant personnel shall be trained on what warning signs to look for. 3) Mechanical moving of woody biomass by front end loaders and other supporting equipment shall be minimized on high wind event days. 4) Objectionable odor is prohibited with first in first out biomass utilization implemented to minimize odors. 5) Daily visual observations of the woody biomass storage areas shall be performed and if conditions are right for fugitive dust formation, procedures from the fugitive dust plan shall be implemented.

BEST MANAGEMENT PRACTICES (BMP) PLAN

Best Management Practice – Fire Prevention /Spontaneous Combustion Minimization	1) Contact local fire marshal to develop fire management plan. Plan shall be maintained on site. 2) Fire Management plan to 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. 3) Daily observations 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. 4) Signs shall be posted at the plant, which identify potential fire hazards. 5) Incoming unprocessed materials shall be stored in areas with a clearance between each storage area. 6) The stacker reclaimer being used shall maximize the removal of older material in order to minimize the stacking of newer material on top of older material. 7) Compaction of woody biomass materials in the storage areas shall be minimized.
Best Management Practice – Quality Assurance of Clean Woody Biomass	1) The feedstock for the bubbling fluidized bed (BFB) boiler will consist of clean woody biomass that will be processed in designated fuel preparation area (or areas) where it will be sorted, screened, and sized as necessary, placed in the storage areas or sent directly to the BFB boiler. 2) The permittee will contract for woody biomass that specifically meets the definition of woody biomass as identified in the permit. The woody biomass will consist of clean untreated wood or untreated wood products including clean untreated lumber, tree stumps (whole or chipped), tree limbs (whole or chipped) and slash. This also includes, but is not limited to, wood, wood residue, bark, or any derivative fuel or residue thereof, in any form, including but not limited to sawdust, sander dust, wood chips, scraps, slabs, millings, shavings, and processed pellets made from wood or other forest residues. 3) The woody biomass feedstock will be delivered to the Hamilton County Plant in vehicles designed to prevent release. 4) For each shipment of woody biomass, the permittee shall record the date, quantity and a description of the material received. 5) 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. 6) The permittee shall maintain records of rejected shipments and disposition thereof. Such records shall be made available to the Department upon request.

BEST AVAILABLE COPY

Unless otherwise specified in the permit, the following conditions apply to all emissions units and activities at the ADAGE 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: 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 and SO_2 Monitors:* For NO_X and SO_2 monitors, the owner or operator shall conduct Performance Specification 2 of 40 CFR part 60, Appendix B.

   c. *HCl CEMS*: The HCl CEMS shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 15, EPA Method OTM 22 or alternative specifications approved by the Department.

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.

d. 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 steam generating unit. 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."

c. *SO_2 Monitors:* The required RATA tests shall be performed using EPA Method 6C in Appendix A of 40 CFR part 60.

d. *HCl CEMS*: The HCl CEMS shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 15, EPA Method OTM 22 or alternative specifications approved by the Department. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, EPA Method OTM 23 or alternative procedures approved by the Department.
A Data Assessment Report shall be made each calendar quarter and reported semiannually to the Compliance Authority. The RATA tests required for the HCl monitor shall be performed using EPA Method 26 or 26A as detailed in Appendix A of 40 CFR 60 or by Method 320 as detailed in Appendix A of 40 CFR 63. The HCl monitor span values shall be set appropriately, considering the allowable methods of operation and corresponding emission standards. Approval of specific initial performance specifications and quality assurance and control (Q&A) procedures must be provided by the Department prior to installation and operation of the CEM system.

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 20 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 BFB boiler stack at the ADAGE facility, excess emissions of NO_X, SO_2 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. <u>Notification Requirements</u>: 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. <u>CEMS Used for Calculating Annual Emissions</u>: 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. <u>Accounting for Missing Data</u>: 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

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

Unless otherwise specified in the permit, the following testing requirements apply to all emissions units at the ADAGE 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 ADAGE project. Parts that are critical to the ADGAE 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:

a. 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

b. 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.

c. 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_2 sample 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_2 concentrations and shall record the output of the systems. For units complying with the percent reduction standard, the SO_2 and either O_2 or CO_2 concentrations shall both be monitored at the inlet and outlet of the SO_2 control device. If the owner or operator has installed and certified SO_2 and O_2 or CO_2 CEMS according to the requirements of §75.20(c)(1) of 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_2 data 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 SO2 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_2 standards 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

40 CFR 75, APPENDIX F, SECTION 5 – MEASUREMENT OF BOILER HEAT INPUT RATE

{Permitting Note: This is the section (Section 5) of Appendix F of 40 CFR 75 including the F-Factor Table for fuels that deals with the calculation of the heat input rate to a steam generating boiler. This procedure is utilized by boilers that fall under the Acid Rain program. This is the procedure that ADAGE will utilize to calculate the heat input rate to the BFB biomass boiler. To access the full version of 40 CFR 75, Appendix F, follow the link at the end of this appendix.}

5. Procedures for Heat Input

Use the following procedures to compute heat input rate to an affected unit (in mmBtu/hr or mmBtu/day):

5.1 Calculate and record heat input rate to an affected unit on an hourly basis, except as provided in sections 5.5 through 5.5.7. The owner or operator may choose to use the provisions specified in §75.16(e) or in section 2.1.2 of appendix D to this part in conjunction with the procedures provided in sections 5.6 through 5.6.2 to apportion heat input among each unit using the common stack or common pipe header.

5.2 For an affected unit that has a flow monitor (or approved alternate monitoring system under subpart E of this part for measuring volumetric flow rate) and a diluent gas (O_2 or CO_2) monitor, use the recorded data from these monitors and one of the following equations to calculate hourly heat input rate (in mmBtu/hr).

5.2.1 When measurements of CO_2 concentration are on a wet basis, use the following equation:

$$HI = Q_w \frac{1}{F_c} \frac{\%CO_{2w}}{100} \qquad (Eq.\ F\text{-}15)$$

Where:

HI = Hourly heat input rate during unit operation, mmBtu/hr.

Q_w = Hourly average volumetric flow rate during unit operation, wet basis, scfh.

F_c = Carbon-based F-factor, listed in section 3.3.5 of this appendix for each fuel, scf/mmBtu.

$\%CO_{2w}$ = Hourly concentration of CO_2 during unit operation, percent CO_2 wet basis.

5.2.2 When measurements of CO_2 concentration are on a dry basis, use the following equation:

$$HI = Q_h \left[\frac{(100 - \%H_2O)}{100 F_c}\right]\left(\frac{\%CO_{2d}}{100}\right) \qquad (Eq.\ F\text{-}16)$$

Where:

HI = Hourly heat input rate during unit operation, mmBtu/hr.

Q_h = Hourly average volumetric flow rate during unit operation, wet basis, scfh.

F_c = Carbon-based F-Factor, listed in section 3.3.5 of this appendix for each fuel, scf/mmBtu.

$\%CO_{2d}$ = Hourly concentration of CO_2 during unit operation, percent CO_2 dry basis.

$\%H_2O$ = Moisture content of gas in the stack, percent.

5.2.3 When measurements of O_2 concentration are on a wet basis, use the following equation:

$$HI = Q_w \frac{1}{F} \frac{\left[(20.9/100)(100 - \%H_2O) - \%O_{2w}\right]}{20.9} \qquad (Eq.\ F\text{-}17)$$

Where:

HI = Hourly heat input rate during unit operation, mmBtu/hr.

Q_w= Hourly average volumetric flow rate during unit operation, wet basis, scfh.

F = Dry basis F-factor, listed in section 3.3.5 of this appendix for each fuel, dscf/mmBtu.

$\%O_{2w}$= Hourly concentration of O_2during unit operation, percent O_2wet basis. For any operating hour where Equation F–17 results in an hourly heat input rate that is ≤ 0.0 mmBtu/hr, 1.0 mmBtu/hr shall be recorded and reported as the heat input rate for that hour.

$\%H_2O$ = Hourly average stack moisture content, percent by volume.

5.2.4 When measurements of O_2concentration are on a dry basis, use the following equation:

$$HI = Q_w \left[\frac{(100-\%H_2O)}{100\ F}\right]\left[\frac{(20.9-\%O_{2d})}{20.9}\right] \qquad (Eq.\ F\text{-}18)$$

Where:

HI = Hourly heat input rate during unit operation, mmBtu/hr.

Q_w= Hourly average volumetric flow during unit operation, wet basis, scfh.

F = Dry basis F-factor, listed in Table 1 at the end of this of this appendix for each fuel, dscf/mmBtu.

$\%H_2O$ = Moisture content of the stack gas, percent.

$\%O_{2d}$= Hourly concentration of O_2during unit operation, percent O_2dry basis.

5.3 Heat Input Summation (for Heat Input Determined Using a Flow Monitor and Diluent Monitor)

5.3.1 Calculate total quarterly heat input for a unit or common stack using a flow monitor and diluent monitor to calculate heat input, using the following equation:

$$HI_q = \sum_{hour=1}^{n} HI_i t_i \qquad (Eq.\ F\text{-}18a)$$

Where:

HI_q= Total heat input for the quarter, mmBtu.

HI_i= Hourly heat input rate during unit operation, using Equation F–15, F–16, F–17, or F–18, mmBtu/hr.

t_i= Hourly operating time for the unit or common stack, hour or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

5.3.2 Calculate total cumulative heat input for a unit or common stack using a flow monitor and diluent monitor to calculate heat input, using the following equation:

$$HI_c = \sum_{q=1}^{\text{the current quarter}} HI_q \qquad (Eq.\ F\text{-}18b)$$

Where:

HI_c= Total heat input for the year to date, mmBtu.

HI_q= Total heat input for the quarter, mmBtu.

5.4 [Reserved]

5.5 For a gas-fired or oil-fired unit that does not have a flow monitor and is using the procedures specified in appendix D to this part to monitor SO_2emissions or for any unit using a common stack for which the owner or operator chooses to determine heat input by fuel sampling and analysis, use the following procedures to calculate hourly heat input rate in mmBtu/hr. The procedures of section 5.5.3 of this appendix shall not be used to determine heat input from a coal unit that is required to comply with the provisions of this part for monitoring, recording, and reporting NO_X mass emissions under a State or federal NO_X mass emission reduction program.

5.5.1 (a) When the unit is combusting oil, use the following equation to calculate hourly heat input rate:

$$HI_o = M_o \frac{GCV_o}{10^6} \qquad (Eq.\ F\text{-}19)$$

Where:

HI_o= Hourly heat input rate from oil, mmBtu/hr.

M_o= Mass rate of oil consumed per hour, as determined using procedures in appendix D to this part, in lb/hr, tons/hr, or kg/hr.

GCV_o= Gross calorific value of oil, as measured by ASTM D240–00, ASTM D5865–01a, or ASTM D4809–00 for each oil sample under section 2.2 of appendix D to this part, Btu/unit mass (all incorporated by reference under (§75.6 of this part).

10^6 = Conversion of Btu to mmBtu.

(b) When performing oil sampling and analysis solely for the purpose of the missing data procedures in §75.36, oil samples for measuring GCV may be taken weekly, and the procedures specified in appendix D to this part for determining the mass rate of oil consumed per hour are optional.

5.5.2 When the unit is combusting gaseous fuels, use the following equation to calculate heat input rate from gaseous fuels for each hour:

$$HI_g = \frac{(Q_g \times GCV_g)}{10^6} \qquad (Eq.\ F\text{-}20)$$

Where:

HI_g= Hourly heat input rate from gaseous fuel, mmBtu/hour.

Q_g= Metered flow rate of gaseous fuel combusted during unit operation, hundred standard cubic feet per hour.

GCV_g= Gross calorific value of gaseous fuel, as determined by sampling (for each delivery for gaseous fuel in lots, for each daily gas sample for gaseous fuel delivered by pipeline, for each hourly average for gas measured hourly with a gas chromatograph, or for each monthly sample of pipeline natural gas, or as verified by the contractual supplier at least once every month pipeline natural gas is combusted, as specified in section 2.3 of appendix D to this part) using ASTM D1826–94 (Reapproved 1998), ASTM D3588–98, ASTM D4891–89 (Reapproved 2006), GPA Standard 2172–96 Calculation of Gross Heating Value, Relative Density and

Compressibility Factor for Natural Gas Mixtures from Compositional Analysis, or GPA Standard 2261–00 Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography, Btu/100 scf (all incorporated by reference under §75.6 of this part).

10^6 = Conversion of Btu to mmBtu.

5.5.3 When the unit is combusting coal, use the procedures, methods, and equations in sections 5.5.3.1–5.5.3.3 of this appendix to determine the heat input from coal for each 24-hour period. (All ASTM methods are incorporated by reference under §75.6 of this part.)

5.5.3.1 Perform coal sampling daily according to section 5.3.2.2 in Method 19 in appendix A to part 60 of this chapter and use ASTM D2234–00, Standard Practice for Collection of a Gross Sample of Coal, (incorporated by reference under §75.6 of this part) Type I, Conditions A, B, or C and systematic spacing for sampling. (When performing coal sampling solely for the purposes of the missing data procedures in §75.36, use of ASTM D2234–00 is optional, and coal samples may be taken weekly.)

5.5.3.2 All ASTM methods are incorporated by reference under §75.6 of this part. Use ASTM D2013–01, Standard Practice for Preparing Coal Samples for Analysis, for preparation of a daily coal sample and analyze each daily coal sample for gross calorific value using ASTM D5865–01a, Standard Test Method for Gross Calorific Value of Coal and Coke. On-line coal analysis may also be used if the on-line analytical instrument has been demonstrated to be equivalent to the applicable ASTM methods under §§75.23 and 75.66.

5.5.3.3 Calculate the heat input from coal using the following equation:

$$HI_c = M_c \frac{GCV_c}{500} \qquad (Eq.\ F\text{-}21)$$

(Eq. F–21)

where:

HIc = Daily heat input from coal, mmBtu/day.

Mc = Mass of coal consumed per day, as measured and recorded in company records, tons.

GCV_c= Gross calorific value of coal sample, as measured by ASTM D3176–89 (Reapproved 2002), or ASTM D5865–01a, Btu/lb. (incorporated by reference under §75.6 of this part).

500 = Conversion of Btu/lb to mmBtu/ton.

5.5.4 For units obtaining heat input values daily instead of hourly, apportion the daily heat input using the fraction of the daily steam load or daily unit operating load used each hour in order to obtain HI_i for use in the above equations. Alternatively, use the hourly mass of coal consumed in equation F–21.

5.5.5 If a daily fuel sampling value for gross calorific value is not available, substitute the maximum gross calorific value measured from the previous 30 daily samples. If a monthly fuel sampling value for gross calorific value is not available, substitute the maximum gross calorific value measured from the previous 3 monthly samples.

5.5.6 If a fuel flow value is not available, use the fuel flowmeter missing data procedures in section 2.4 of appendix D of this part. If a daily coal consumption value is not available, substitute the maximum fuel feed rate during the previous thirty days when the unit burned coal.

5.5.7 Results for samples must be available no later than thirty calendar days after the sample is composited or taken. However, during an audit, the Administrator may require that the results be available in five business days, or sooner if practicable.

5.6 Heat Input Rate Apportionment for Units Sharing a Common Stack or Pipe

5.6.1 Where applicable, the owner or operator of an affected unit that determines heat input rate at the unit level by apportioning the heat input monitored at a common stack or common pipe using megawatts shall apportion the heat input rate using the following equation:

$$HI_i = HI_{CS}\left(\frac{t_{CS}}{t_i}\right)\left[\frac{MW_i t_i}{\sum_{i=1}^{n} MW_i t_i}\right] \qquad (Eq.\ F\text{-}21a)$$

Where:

HI_i= Heat input rate for a unit, mmBtu/hr.

HI_{cs}= Heat input rate at the common stack or pipe, mmBtu/hr.

MW_i= Gross electrical output, MWe.

t_i= Unit operating time, hour or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

t_{CS}= Common stack or common pipe operating time, hour or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

n = Total number of units using the common stack or pipe.

i = Designation of a particular unit.

5.6.2 Where applicable, the owner or operator of an affected unit that determines the heat input rate at the unit level by apportioning the heat input rate monitored at a common stack or common pipe using steam load shall apportion the heat input rate using the following equation:

$$HI_i = HI_{CS}\left(\frac{t_{CS}}{t_i}\right)\left[\frac{SF_i t_i}{\sum_{i=1}^{n} SF_i t_i}\right] \qquad (Eq.\ F\text{-}21b)$$

Where:

HI_i= Heat input rate for a unit, mmBtu/hr.

HI_{CS}= Heat input rate at the common stack or pipe, mmBtu/hr.

SF = Gross steam load, lb/hr, or mmBtu/hr.

t_i= Unit operating time, hour or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

t_{CS}= Common stack or common pipe operating time, hour or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

n = Total number of units using the common stack or pipe.

i = Designation of a particular unit.

5.7 Heat Input Rate Summation for Units with Multiple Stacks or Pipes

The owner or operator of an affected unit that determines the heat input rate at the unit level by summing the heat input rates monitored at multiple stacks or multiple pipes shall sum the heat input rates using the following equation:

$$HI_{Unit} = \frac{\sum_{s=1}^{n} HI_s t_s}{t_{Unit}} \qquad (Eq.\ F\text{-}21c)$$

Where:

HI_{Unit}= Heat input rate for a unit, mmBtu/hr.

HI_s= Heat input rate for the individual stack, duct, or pipe, mmBtu/hr.

t_{Unit}= Unit operating time, hour or fraction of the hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

t_s= Operating time for the individual stack or pipe, hour or fraction of the hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

s = Designation for a particular stack, duct, or pipe.

5.8 Alternate Heat Input Apportionment for Common Pipes

As an alternative to using Equation F-21a or F-21b in section 5.6 of this appendix, the owner or operator may apportion the heat input rate at a common pipe to the individual units served by the common pipe based on the fuel flow rate to the individual units, as measured by uncertified fuel flowmeters. This option may only be used if a fuel flowmeter system that meets the requirements of appendix D to this part is installed on the common pipe. If this option is used, determine the unit heat input rates using the following equation:

$$HI_i = HI_{CP}\left(\frac{t_{CP}}{t_i}\right)\left[\frac{FF_i t_i}{\sum_{i=1}^{n} FF_i t_i}\right] \qquad (Eq.\ F\text{-}21d)$$

Where:

HI_i= Heat input rate for a unit, mmBtu/hr.

HI_{CP}= Heat input rate at the common pipe, mmBtu/hr.

FF_i= Fuel flow rate to a unit, gal/min, 100 scfh, or other appropriate units.

t_i= Unit operating time, hour or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

t_{CP}= Common pipe operating time, hour or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

n = Total number of units using the common pipe.

i = Designation of a particular unit.

3.3.5 F, F_c=a factor representing a ratio of the volume of dry flue gases generated to the caloric value of the fuel combusted (F), and a factor representing a ratio of the volume of CO_2generated to the calorific value of the fuel combusted (F_c), respectively. Table 1 lists the values of F and F_c for different fuels. The permittee at their discretion may use the procedure of 40 CFR Part 75, Appendix F, Section 3.3.6 to calculate a site specific F factor for the BFB biomass boiler at the ADAGE facility.

Table 1—F- and F_c-Factors[1]

Fuel	F-factor (dscf/mmBtu)	F_C-factor (scf CO_2/mmBtu)
Coal (as defined by ASTM D388–99[2]):		
Anthracite	10,100	1,970
Bituminous	9,780	1,800
Subbituminous	9,820	1,840
Lignite	9,860	1,910
Petroleum Coke	9,830	1,850
Tire Derived Fuel	10,260	1,800
Oil	9,190	1,420
Gas:		
Natural gas	8,710	1,040
Propane	8,710	1,190
Butane	8,710	1,250
Wood:		
Bark	9,600	1,920
Wood residue	9,240	1,830

[1]Determined at standard conditions: 20 °C (68 °F) and 29.92 inches of mercury.
[2]Incorporated by reference under §75.6 of this part.

http://ecfr.gpoaccess.gov/cgi/t/text/text-idx?c=ecfr&sid=c75c9c674aae0122ef20c6660c3a874e&rgn=div9&view=text&node=40:16.0.1.1.4.9.1.6.11&idno=40

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 ( );
    c. Compliance with National Emission Standards for Hazardous Air Pollutants ( ); and
    d. 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 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.

NSPS, SUBPART IIII - STATIONARY COMPRESSION IGNITION INTERNAL COMBUSTION ENGINES

A 1800 kW or less emergency generator (EU ID 004) and two 500 hp or less water pumps (EU-005 and EU-006) are proposed for the ADAGE facility and they 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 ZZZZ – STATIONARY RECIPROCATING INTERNAL COMBUSTION ENGINES

A 1800 kW or less emergency generator (EU ID 004) and two 500 hp or less water pumps (EU-005 and EU-006) are proposed for the ADAGE facility 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:	Thursday, December 10, 2009 5:37 PM
To:	'reed.wills@duke-energy.com'
Cc:	'dcibik@pirnie.com'; Kirts, Christopher; 'forney.kathleen@epamail.epa.gov'; 'abrams.heather@epa.gov'; 'bettyjohnson@shareinet.net'; 'rprtcard@bellsouth.net'; 'hopeforcleanwater@yahoo.com'; 'hamiltoncounty@alltel.net'; 'rstewart@fppaea.org'; Gibson, Victoria; Read, David; Linero, Alvaro; Walker, Elizabeth (AIR)
Subject:	ADAGE HAMILTON LLC - HAMILTON CO WOODY BIOMASS PLANT; 0470016-001-AC - Rev Draft
Attachments:	0470016-001-AC RADAGEIntent.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/0470016.001.AC.R_pdf.zip

Owner/Company Name: ADAGE HAMILTON LLC
Facility Name: HAMILTON CO WOODY BIOMASS PLANT
Project Number: 0470016-001-AC
Permit Status: REV DRAFT
Permit Activity: CONSTRUCTION
Facility County: HAMILTON
Processor: David Read

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://www.dep.state.fl.us/air/eproducts/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

Sylvia Livingston
Bureau of Air Regulation
Division of Air Resource Management (DARM)
850/921-9506
sylvia.livingston@dep.state.fl.us

Livingston, Sylvia

From: Wills, Reed [Reed.Wills@duke-energy.com]
Sent: Thursday, December 17, 2009 10:28 PM
To: Livingston, Sylvia; Linero, Alvaro
Cc: Morabito, Bruno D
Subject: RE: ADAGE HAMILTON LLC - HAMILTON CO WOODY BIOMASS PLANT; 0470016-001-AC - Rev Draft

Sylvia and Al,
We have notified your office and finalized the permit but again I failed to follow your straightforward instructions on the reply.
Sorry for that, we are able to view all documents.
Thanks for your professional approach and responsiveness, and our best wishes to the DEP team to enjoy the upcoming holidays.
Reed Wills

From: Livingston, Sylvia [mailto:Sylvia.Livingston@dep.state.fl.us]
Sent: Thursday, December 10, 2009 5:37 PM
To: Wills, Reed
Cc: dcibik@pirnie.com; Kirts, Christopher; forney.kathleen@epamail.epa.gov; abrams.heather@epa.gov; bettyjohnson@shareinet.net; rprtcard@bellsouth.net; hopeforcleanwater@yahoo.com; hamiltoncounty@alltel.net; rstewart@fppaea.org; Gibson, Victoria; Read, David; Linero, Alvaro; Walker, Elizabeth (AIR)
Subject: ADAGE HAMILTON LLC - HAMILTON CO WOODY BIOMASS PLANT; 0470016-001-AC - Rev Draft

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http://ARM-PERMIT2K.dep.state.fl.us/adh/prod/pdf_permit_zip_files/0470016.001.AC.R_pdf.zip

Owner/Company Name: ADAGE HAMILTON LLC
Facility Name: HAMILTON CO WOODY BIOMASS PLANT
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Livingston, Sylvia

From: Linero, Alvaro
Sent: Friday, December 18, 2009 6:25 AM
To: Wills, Reed; Livingston, Sylvia
Cc: Morabito, Bruno D
Subject: RE: ADAGE HAMILTON LLC - HAMILTON CO WOODY BIOMASS PLANT; 0470016-001-AC - Rev Draft

Thank you very much. and happy holidays.

Al Linero.

-----Original Message-----
From: Wills, Reed [mailto:Reed.Wills@duke-energy.com]
Sent: Thu 12/17/2009 10:27 PM
To: Livingston, Sylvia; Linero, Alvaro
Cc: Morabito, Bruno D
Subject: RE: ADAGE HAMILTON LLC - HAMILTON CO WOODY BIOMASS PLANT; 0470016-001-AC - Rev Draft

Sylvia and Al,
We have notified your office and finalized the permit but again I failed to follow your straightforward instructions on the reply.
Sorry for that, we are able to view all documents.
Thanks for your professional approach and responsiveness, and our best wishes to the DEP team to enjoy the upcoming holidays.
Reed Wills

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Sent: Thursday, December 10, 2009 5:37 PM
To: Wills, Reed
Cc: dcibik@pirnie.com; Kirts, Christopher; forney.kathleen@epamail.epa.gov; abrams.heather@epa.gov; bettyjohnson@shareinet.net; rprtcard@bellsouth.net; hopeforcleanwater@yahoo.com; hamiltoncounty@alltel.net; rstewart@fppaea.org; Gibson, Victoria; Read, David; Linero, Alvaro; Walker, Elizabeth (AIR)
Subject: ADAGE HAMILTON LLC - HAMILTON CO WOODY BIOMASS PLANT; 0470016-001-AC - Rev Draft

Dear Sir/ Madam:

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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

Sylvia Livingston
Bureau of Air Regulation
Division of Air Resource Management (DARM)
850/921-9506
sylvia.livingston@dep.state.fl.us

Note: The attached document is in Adobe Portable Document Format (pdf). Adobe Acrobat Reader can be downloaded for free at the following internet site: <http://www.adobe.com/products/acrobat/readstep.html

The Department of Environmental Protection values your feedback as a customer. DEP Secretary Michael W. Sole is committed to continuously assessing and improving the level and quality of services provided to you. Please take a few minutes to comment on the quality of service you received. Simply click on this link to the DEP Customer Survey. Thank you in advance for completing the survey.