SENDER: *COMPLETE THIS SECTION*

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Mr. Robert G. Moore
VP of Power Gen & Transmission
Gulf Power Company
OUC Stanton A Combined Cycle
Addition
One Energy Place
Pensacola, FL 32520-0328

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)*

B. Date of Delivery 5/21/0

C. Signature
X [signature]
☐ Agent
☐ Addressee

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? *(Extra Fee)* ☐ Yes

2. Article Number *(Copy from service label)*
7099 3400 0000 1450 3214

PS Form 3811, July 1999 Domestic Return Receipt 102595-00-M-0952

U.S. Postal Service
CERTIFIED MAIL RECEIPT
(Domestic Mail Only; No Insurance Coverage Provided)

7099 3400 0000 1450 3214

Article Sent To:

Postage	$
Certified Fee	
Return Receipt Fee (Endorsement Required)	
Restricted Delivery Fee (Endorsement Required)	
Total Postage & Fees	$

Postmark Here
OUC Stanton

Name *(Please Print Clearly) (to be completed by mailer)*
Mr. Robert G. Moore
Street, Apt. No., or PO Box No.
One Energy Place
City, State, ZIP+4
Pensacola, FL 32520-0328

PS Form 3800, July 1999 See Reverse for Instructions

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Mr. Richard Crotty, Chair
Orange County Board of County Commissioners
Administration Bldg., 5th Fl
201 S Rosalind Ave.
Orlando, FL 32801

A. Received by (Please Print Clearly) Acevedo

B. Date of Delivery

C. Signature

X

☐ Agent
☐ Addressee

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? (Extra Fee) ☐ Yes

2. Article Number (Copy from service label)
7099 3400 0000 1450 3184

PS Form 3811, July 1999 Domestic Return Receipt 102595-00-M-0952

U.S. Postal Service
CERTIFIED MAIL RECEIPT
(Domestic Mail Only; No Insurance Coverage Provided)

7099 3400 0000 1450 3184

Article Sent To:

Postage	$
Certified Fee	
Return Receipt Fee (Endorsement Required)	
Restricted Delivery Fee (Endorsement Required)	
Total Postage & Fees	$

Postmark Here
Orange County

Name (Please Print Clearly) (to be completed by mailer)
Mr. Richard Crotty, Chair
Street, Apt. No.; or PO Box No.
201 S. Rosalind Ave
City, State, ZIP+4
Orlando, FL 32801

PS Form 3800, July 1999 See Reverse for Instructions

May 17, 2001

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Robert G. Moore, VP of Power Gen. and Transmission
Gulf Power Company
OUC Stanton A Combined Cycle Addition
One Energy Place
Pensacola, Florida 32520-0328

Re: DEP File No. 0950137-002-AC (PSD-FL-313)
OUC/KUA/FMPA/Southern Company – Florida, LLC

Dear Mr. Moore:

Enclosed is one copy of the Draft Permit, Technical Evaluation and Preliminary Determination, and Draft BACT Determination, for the OUC Stanton A Combined Cycle addition to be located at 5100 South Alafaya Trail, Orlando, Orange County. The Department's Intent to Issue PSD Permit and the "PUBLIC NOTICE OF INTENT TO ISSUE PSD PERMIT" are also included.

The "PUBLIC NOTICE OF INTENT TO ISSUE PSD PERMIT" must be published one time only as soon as possible in a newspaper of general circulation in the area affected, pursuant to Chapter 50, Florida Statutes. Proof of publication, i.e., newspaper affidavit, must be provided to the Department's Bureau of Air Regulation office within 7 (seven) days of publication. Failure to publish the notice and provide proof of publication within the allotted time may result in the denial of the permit.

Please submit any written comments you wish to have considered concerning the Department's proposed action to A. A. Linero, P.E., Administrator, New Source Review Section at the above letterhead address. If you have any questions, please call Michael P. Halpin, P.E. at 850/921-9519.

Sincerely,

for C. H. Fancy, P.E., Chief,
Bureau of Air Regulation

CHF/mph

Enclosures

In the Matter of an
Application for Permit by:

Mr. Robert G. Moore, VP Gulf Power Company
OUC/KUA/FMPA/Southern Company – Florida, LLC
One Energy Place
Pensacola, FL 32520-0328
/

DEP File No. 0950137-002-AC (PSD-313)
Curtis H. Stanton Energy Center
Orange County

INTENT TO ISSUE PSD PERMIT

The Department of Environmental Protection (Department) gives notice of its intent to issue a permit under the requirements for the Prevention of Significant Deterioration of Air Quality (copy of Draft PSD Permit attached) for the proposed project, detailed in the application specified above and the attached Technical Evaluation and Preliminary Determination, for the reasons stated below.

The applicant, OUC/KUA/FMPA/Southern Company – Florida, LLC, applied on January 22, 2001 to the Department for a PSD permit to construct a 700 megawatt combined cycle electrical power generating unit consisting of: two nominal 170 MW "F" class combustion turbine-electrical generators; two supplementally fired heat recovery steam generators; one 300 MW steam-electrical generator; one mechanical draft cooling tower; a fuel oil storage tank and ancillary equipment. The application became complete on May 1, 2001. The project will be located at the existing Curtis H. Stanton Energy Center, 5100 South Alafaya Trail, Orlando, Orange County.

The Department has permitting jurisdiction under the provisions of Chapter 403, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210, and 62-212. The above actions are not exempt from permitting procedures. The Department has determined that a PSD permit and a determination of Best Available Control Technology for the control of carbon monoxide, nitrogen oxide, sulfur dioxide, sulfuric acid mist, volatile organic compounds and particulate matter is required to conduct the work.

The Department intends to issue this PSD permit based on the belief that reasonable assurances have been provided to indicate that operation of these emission units will not adversely impact air quality, and the emission units will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297, F.A.C. and 40 CFR 52.21.

Pursuant to Section 403.815, F.S., and Rule 62-110.106(7)(a)1., F.A.C., you (the applicant) are required to publish at your own expense the enclosed "Public Notice of Intent to Issue PSD Permit." The notice shall be published one time only in the legal advertisement section of a newspaper of general circulation in the area affected. For the purpose of these rules, "publication in a newspaper of general circulation in the area affected" means publication in a newspaper meeting the requirements of Sections 50.011 and 50.031, F.S., in the county where the activity is to take place. Where there is more than one newspaper of general circulation in the county, the newspaper used must be one with significant circulation in the area that may be affected by the permit. If you are uncertain that a newspaper meets these requirements, please contact the Department at the address or telephone number listed below. The applicant shall provide proof of publication to the Department's Bureau of Air Regulation, at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, Florida 32399-2400 (Telephone: 850/488-0114; Fax 850/ 922-6979). The Department suggests that you publish the notice within thirty days of receipt of this letter. You must provide proof of publication within seven days of publication, pursuant to Rule 62-110.106(5), F.A.C. No permitting action for which published notice is required shall be granted until proof of publication of notice is made by furnishing a uniform affidavit in substantially the form prescribed in section 50.051, F.S. to the office of the Department issuing the permit or other authorization. Failure to publish the notice and provide proof of publication may result in the denial of the permit pursuant to Rules 62-110.106(9) & (11), F.A.C.

The Department will issue the final permit with the attached conditions and after approval of the certification pursuant to the Florida Power Plant Siting Act (Sections 403.501-519, F.S.) unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments and requests for a public hearing (meeting) concerning the proposed permit issuance action for a period of thirty (30) days from the date of publication of "Public Notice of Intent to Issue PSD permit." Written comments and requests for a public meeting should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below. If a petition for an administrative hearing on the Department's Intent to Issue is filed by a substantially affected person, that hearing shall be consolidated with the certification hearing, as provided under Section 403.507(3). Mediation is not available in this proceeding.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station # 35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen 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 will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code.

A petition that disputes the material facts on which the Department'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 how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (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; and (g) A statement of the relief sought by the petitioner, stating precisely the action 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 Department'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

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

In addition to the above, a person subject to regulation has a right to apply for a variance from or waiver of the requirements of particular rules, on certain conditions, under Section 120.542, F.S. The relief provided by this state statute applies only to state rules, not statutes, and not to any federal regulatory requirements. Applying for a variance or waiver does not substitute or extend the time for filing a petition for an administrative hearing or exercising any other right that a person may have in relation to the action proposed in this notice of intent.

The application for a variance or waiver is made by filing a petition with the Office of General Counsel of the Department, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000. The petition must specify the following information: (a) The name, address, and telephone number of the petitioner; (b) The name, address, and telephone number of the attorney or qualified representative of the petitioner, if any; (c) Each rule or portion of a rule from which a variance or waiver is requested; (d) The citation to the statute underlying (implemented by) the rule identified in (c) above; (e) The type of action requested; (f) The specific facts that would justify a variance or waiver for the petitioner; (g) The reason why the variance or waiver would serve the purposes of the underlying statute (implemented by the rule); and (h) A statement whether the variance or waiver is permanent or temporary and, if temporary, a statement of the dates showing the duration of the variance or waiver requested.

The Department will grant a variance or waiver when the petition demonstrates both that the application of the rule would create a substantial hardship or violate principles of fairness, as each of those terms is defined in Section 120.542(2) F.S., and that the purpose of the underlying statute will be or has been achieved by other means by the petitioner.

Persons subject to regulation pursuant to any federally delegated or approved air program should be aware that Florida is specifically not authorized to issue variances or waivers from any requirements of any such federally delegated or approved program. The requirements of the program remain fully enforceable by the Administrator of the EPA and by any person under the Clean Air Act unless and until the Administrator separately approves any variance or waiver in accordance with the procedures of the federal program.

Executed in Tallahassee, Florida.

A A Linn, P.E.
for C. H. Fancy, P.E., Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this INTENT TO ISSUE PSD PERMIT (including the PUBLIC NOTICE, Technical Evaluation and Preliminary Determination, Draft BACT Determination, and the DRAFT PSD permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 5/17/01 to the person(s) listed:

Robert G. Moore, Gulf Power *
Chair of County Commission, Orange County *
James O. Vick, Gulf Power
Rodney I Unruh, P.E. (Black & Veatch)
Gregg Worley, EPA
John Bunyak, NPS
Len Kozlov, DEP-Central District
Marie Driscoll, Orange County EPD
Tasha O. Buford, E., Attorney
Mr. Hamilton S. Oven, DEP-Siting

Clerk Stamp

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

Charlotte J. Hayes 5/17/01
(Clerk) (Date)

PUBLIC NOTICE OF INTENT TO ISSUE PSD PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

DEP File No. PSD-FL-313 (PA 81-14SA2)
OUC Curtis H. Stanton Energy Center
Unit A Combined Cycle Addition
Orange County

The Department of Environmental Protection (Department) gives notice of its intent to issue a PSD permit to the following joint owners: OUC/KUA/FMPA/Southern Company – Florida, LLC. The permit is to install a combined cycle power-generating unit at the existing OUC Stanton Energy Center, located at 5100 South Alafaya Trail, Orlando, Orange County. A Best Available Control Technology (BACT) determination was required pursuant to Rule 62-212.400, F.A.C. and 40 CFR52.21 for emissions of particulate matter (PM and PM_{10}), volatile organic compounds (VOC), sulfur dioxide (SO_2), sulfuric acid mist (SAM), carbon monoxide (CO) and nitrogen oxides (NO_X). The applicant's name and address is Mr. Robert G. Moore, Gulf Power Company, One Energy Place, Pensacola, FL 32520-0328.

The project consists of two nominal (existing) 170 MW GE 7FA combustion turbine-electrical generators configured for combined cycle operation, operating on natural gas with 0.05% sulfur oil backup (1000 hours per year); two supplementally-fired (natural gas) heat recovery steam generators (HRSG); one 300 MW (nominal output) steam turbine; one fresh water cooling tower; a fuel oil storage tank and ancillary equipment.

NO_x emissions will be controlled by Dry Low NO_x combustors and SCR to 3.5 parts per million (ppm) while firing natural gas, and by water injection and SCR to 10 ppm while firing fuel oil. Emissions of carbon monoxide (CO) will be controlled to 14 ppm while firing oil and 17 ppm while firing gas. Emissions of volatile organic compounds (VOC), sulfur dioxide (SO_2), sulfuric acid mist (SAM), and particulate matter (PM/PM_{10}) will be very low because of the inherently clean fuels and methods of combustion employed.

The following maximum potential annual emissions (in tons per year) summarize the maximum increase in regulated air pollutants as a result of this project.

Pollutants	Maximum Facility Emissions (TPY)
PM/PM_{10}	128
NO_x	315
SO_2	134
SAM	18
VOC	106
CO	373

An air quality impact analysis was conducted. Emissions from the facility will not contribute to or cause a violation of any state or federal ambient air quality standards. All impacts to Class II areas are less than significant. All impacts to Class I areas are also less than significant.

The Department will issue the FINAL permit with the attached conditions and after approval of the certification pursuant to the Florida Power Plant Siting Act (Sections 403.501-519, F.S.) unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments and requests for a public meeting concerning the proposed permit issuance action for a period of thirty (30) days from the date of publication of "Public Notice of Intent to Issue PSD Permit." Written comments should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to Sections 120.569 and 120.57 F.S., before the deadline for filing a petition. If a petition for an administrative hearing on the Department's Intent to Issue is filed by a substantially affected person, that hearing shall be consolidated with the certification hearing, as provided under Section 403.507(3). The procedures for petitioning for a hearing are set forth below. Mediation is not available in this proceeding.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station # 35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen 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 will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code.

A petition that disputes the material facts on which the Department'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 how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, as well as the rules and statutes which entitle the petitioner to relief; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action 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 Department'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

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

A complete project file is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at:

Dept of Environmental Protection
Bureau of Air Regulation
111 S. Magnolia Drive, Suite 4
Tallahassee, Florida 32301
Telephone: 850/488-0114
Fax: 850/922-6979

Dept. of Environmental Protection
Central District Office
3319 Maguire Boulevard, Suite 232
Orlando, Florida 32803-3767
Telephone: 407/894-7555
Fax: 407/897-2966

The complete project file includes the application, technical evaluations, Draft Permit, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Administrator, New Resource Review Section at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114, for additional information. The Technical Evaluation and Preliminary Determination as well as the Draft BACT Determination and Permit may be viewed at http://www8.myflorida.com/licensingpermitting/learn/environment/air/airpermit.html by clicking on *Utilities and Other Facilities Permits Issued.*

TECHNICAL EVALUATION

AND

PRELIMINARY DETERMINATION

OUC/KUA/FMPA/Southern Company – Florida, LLC

Stanton Unit A Combined Cycle Project

700-Megawatt Combined Cycle Addition

Orange County

PSD-FL-313, PA81-14SA2

Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation
New Source Review Section

May 17, 2001

TECHNICAL EVALUATION AND PRELIMINARY DETERMINATION

1. APPLICATION INFORMATION

1.1 Applicant Name and Address

OUC/KUA/FMPA/Southern Company – Florida, LLC
James O. Vick, Manager Environmental Affairs – Gulf Power
One Energy Place
Pensacola, FL 32520-0328

Authorized Representative: Mr. Robert G. Moore, VP of Power Generation and Transmission

1.2 Reviewing and Process Schedule

01-22-01:	Date of Receipt of Application
03-12-01:	Request for Additional Information
05-01-01:	Application Complete
05-17-01:	Intent to Issue PSD Permit

2. FACILITY INFORMATION

2.1 Facility Location

The OUC Curtis H. Stanton Energy Center is located at 5100 South Alafaya Trail, Orlando, Orange County. This site is approximately 140 kilometers east-southeast of the Class I Chassahowitzka National Wildlife Refuge. UTM coordinates for this facility are Zone 17; 483.61 km E; 3151.1 km N. See Figures 1 and 2 below.

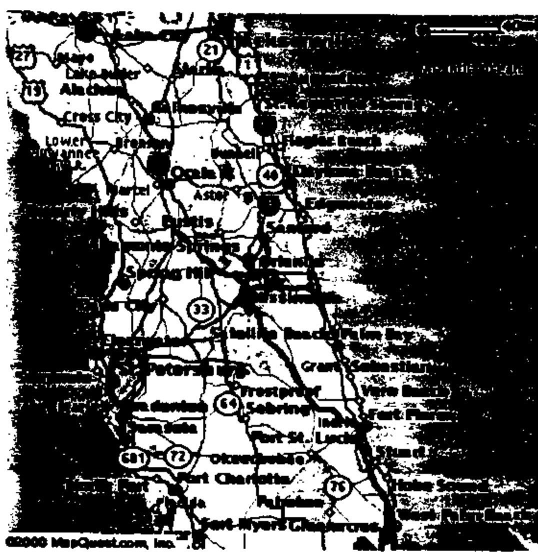


FIGURE 1

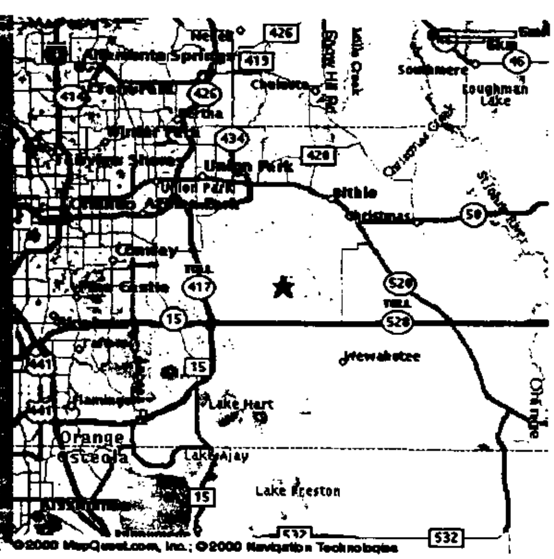


FIGURE 2

2.2 Standard Industrial Classification Codes (SIC)

Industry Group No.	49	Electric, Gas, and Sanitary Services
Industry No.	4911	Electric Services

2.3 Facility Category

The facility is classified as a Major or Title V Source of air pollution because emissions of at least one regulated air pollutant, such as particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), nitrogen oxides (NO_X), carbon monoxide (CO), or volatile organic compounds (VOC) exceeds 100 TPY.

The facility is within an industry included in the list of the 28 Major Facility Categories per Table 212.400-1, F.A.C

As a Major Facility, project emissions greater than the Significant Emission Rates given in Table 212.400-2 (100 TPY of CO; 40 TPY of NO_X, SO_2, or VOC, 25/15 TPY of PM/PM_{10}) require review per the PSD rules and a determination of Best Available Control Technology (BACT). This facility is also subject to the Title IV Acid Rain Program, 40 CFR 72.

3. PROJECT DESCRIPTION

This permit addresses the following emissions units:

EMISSION UNIT	SYSTEM	Emission Unit Description
025	Power Generation	One nominal 170 Megawatt Gas Combustion Turbine-Electrical Generator configured as a combined cycle unit, complete with supplementary fired HRSG
026	Power Generation	One nominal 170 Megawatt Gas Combustion Turbine-Electrical Generator configured as a combined cycle unit, complete with supplementary fired HRSG
027	Water Cooling	One 10 cell Cooling Tower
028	Fuel Storage	One 1,680,000 Gallon Distillate Fuel Oil Storage Tank

The applicant proposes to install a combined cycle unit at the existing facility. This existing facility consists of two fossil fuel fired steam electric generating stations, E.U. ID No. -001 (Unit No. 1) and -002 (Unit No. 2); also, there are storage and handling facilities for solid fuels, fly ash, limestone, gypsum, slag, and bottom ash.

The project includes: two nominal 170 MW, General Electric "F" Class (PG7241FA) combustion turbine-electrical generators, fired with pipeline natural gas or diesel and equipped with evaporative coolers on the inlet air system; two supplementally fired heat recovery steam generators (HRSGs), each with a 160 ft. stack; one steam turbine-electrical generator rated at approximately 300 MW; one fresh water cooling tower; one distillate fuel storage tank and ancillary equipment.

The turbines will be equipped with Dry Low NO_X combustors as well as an SCR in order to control NO_X emissions to 3.5 ppmvd at 15% O_2 while firing natural gas and 10 ppmvd while firing oil using SCR plus water injection. Each combustion turbine will have a maximum heat input rating of 2,402 (Natural Gas while firing duct burners) and 2,068 MMBtu/hr (oil), while the maximum duct burner heat input will be 533 MMBtu/hr (Natural Gas). The referenced CT heat inputs are specified as cases 4 and 20 (respectively) in the application.

The main fuel will be pipeline quality natural gas and the units will operate up to 8760 hours per year. Low sulfur distillate fuel oil will be fired for up to 1000 hours per year in each CT. Emission increases will occur for particulate matter (PM and PM_{10}), sulfur dioxide (SO_2), sulfuric acid mist (SAM), carbon monoxide (CO), volatile organic compounds (VOC), and nitrogen oxides (NO_X). PSD review is required for each of these pollutants, since emissions, per the application, will increase by more than their respective significant emissions levels.

The application was prepared by Black & Veatch.

4. PROCESS DESCRIPTION

A gas turbine is an internal combustion engine that operates with rotary rather than reciprocating motion. Ambient air is drawn into the compressor of the 7FA where it is then directed to the combustor section, fuel is introduced, ignited, and burned. The combustion section consists of multiple separate can-annular combustors instead of a single combustion chamber.

Flame temperatures in a typical combustor section can reach 3600 degrees Fahrenheit (°F). Units such as the 7FA operate at lower flame temperatures, which minimize NO_X formation. The hot combustion gases are then diluted with additional cool air and directed to the turbine section at temperatures up to 2700 °F. Energy is recovered within the turbine section in the form of shaft horsepower, of which typically more than 50 percent is required to drive the internal compressor section. The balance of recovered shaft energy is available to drive the external load unit such as an electrical generator.

There are three basic operating cycles for gas turbines. These are simple cycle, regenerative, and combined cycles. In this project, the 7FA will operate in the combined cycle mode and as a continuous duty unit (versus an intermittent duty peaking unit).

In combined cycle operation, the gas turbine drives an electric generator while the exhausted gases are used to raise steam in a heat recovery steam generator (HRSG). In this case, most of the steam is fed to a separate steam turbine, which also drives an electrical generator. Typical combined cycle efficiencies are up to 55 percent. The 7FA can achieve over 50 percent efficiency in combined cycle operation, especially if the gas turbine and the HRSG/steam generator power a common shaft connected to a single electric generator. See Figures 3 and 4 below.

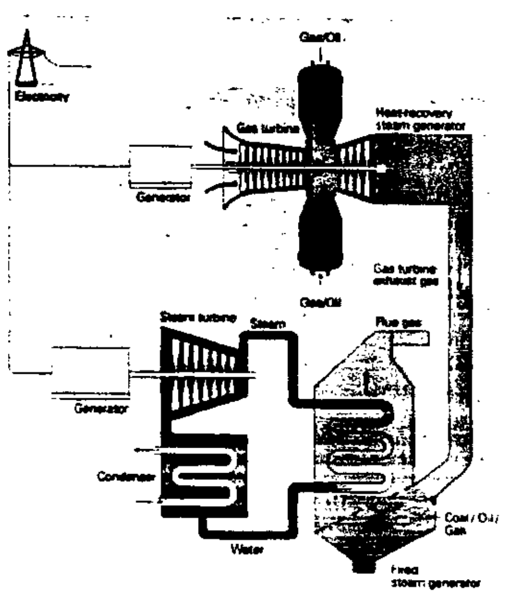


FIGURE 3

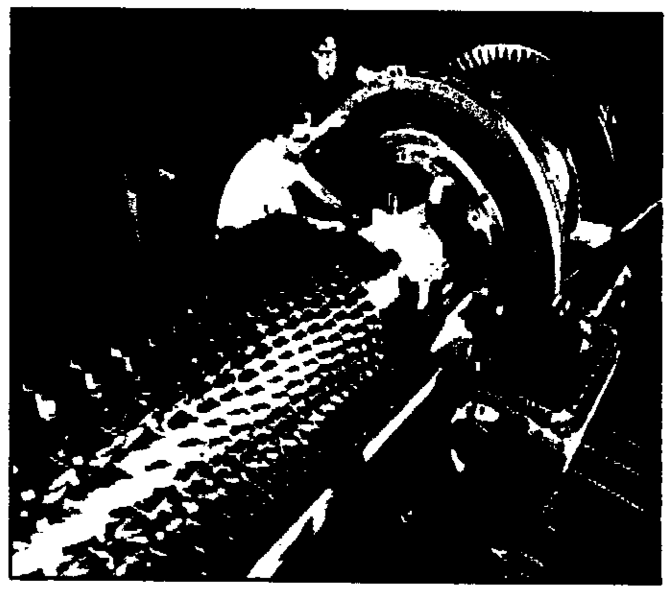


FIGURE 4

Additional process information and control measures to minimize NO_X formation are given in the draft BACT Determination distributed with this evaluation.

5. RULE APPLICABILITY

The proposed project is subject to preconstruction review requirements under the provisions of 40 CFR 52.21, Chapter 403, Florida Statutes, and Chapters 62-4, 62-204, 62-210, 62-212, 62-214, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.).

This facility is located in Orange County, an area designated as attainment for all criteria pollutants in accordance with Rule 62-204.360, F.A.C. The proposed project is subject to review under Rule 62-212.400., F.A.C., Prevention of Significant Deterioration (PSD), because the potential emission increases for PM/PM_{10}, CO, SAM, SO_2 and NO_X exceed the significant emission rates given in Chapter 62-212, Table 62-212.400-2, F.A.C.

This PSD review consists of a determination of Best Available Control Technology (BACT) for PM/PM_{10}, SO_2, SAM, VOC, CO and NO_X. An analysis of the air quality impact from proposed project upon soils, vegetation and visibility is required along with air quality impacts resulting from associated commercial, residential, and industrial growth.

This project will also be reviewed for Site Certification under the Power Plant Siting Act.

The emission units affected by this PSD permit shall comply with all applicable provisions of the Florida Administrative Code (including applicable portions of the Code of Federal Regulations incorporated therein) and, specifically, the following Chapters and Rules:

5.1 State Regulations

Chapter 62-17	Electrical Power Siting
Chapter 62-4	Permits.
Rule 62-204.220	Ambient Air Quality Protection
Rule 62-204.240	Ambient Air Quality Standards
Rule 62-204.260	Prevention of Significant Deterioration Increments
Rule 62-204.800	Federal Regulations Adopted by Reference
Rule 62-210.300	Permits Required
Rule 62-210.350	Public Notice and Comments
Rule 62-210.370	Reports
Rule 62-210.550	Stack Height Policy
Rule 62-210.650	Circumvention
Rule 62-210.700	Excess Emissions
Rule 62-210.900	Forms and Instructions
Rule 62-212.300	General Preconstruction Review Requirements
Rule 62-212.400	Prevention of Significant Deterioration
Rule 62-213	Operation Permits for Major Sources of Air Pollution
Rule 62-214	Requirements For Sources Subject To The Federal Acid Rain Program
Rule 62-296.320	General Pollutant Emission Limiting Standards
Rule 62-297.310	General Test Requirements
Rule 62-297.401	Compliance Test Methods
Rule 62-297.520	EPA Continuous Monitor Performance Specifications

5.2 Federal Rules

40 CFR 52.21	Prevention of Significant Deterioration
40 CFR 60	NSPS Subparts GG and Db
40 CFR 60	Applicable sections of Subpart A, General Requirements
40 CFR 72	Acid Rain Permits (applicable sections)
40 CFR 73	Allowances (applicable sections)
40 CFR 75	Monitoring (applicable sections including applicable appendices)
40 CFR 77	Acid Rain Program-Excess Emissions (future applicable requirements)

6. SOURCE IMPACT ANALYSIS

6.1 Emission Limitations

The proposed project will emit the following PSD pollutants (Table 212.400-2): particulate matter, sulfur dioxide, nitrogen oxides, volatile organic compounds, carbon monoxide and sulfuric acid mist. The applicant's proposed annual emissions are summarized in the Table below and form the basis of the source impact review. The Department's proposed permitted allowable emissions for these Emission Units are summarized in the Draft BACT document and Specific Conditions Nos. 21 through 25 of Draft Permit PSD-FL-313.

6.2 Emission Summary

The emissions for all PSD pollutants as a result of the construction of this facility are presented below:

FACILITY EMISSIONS (TPY) AND PSD APPLICABILITY

Pollutants	Two CT/HRSG with Duct Burners[1]	Cooling Tower	Distillate Fuel Tank	Total	PSD Significance	PSD REVIEW?
PM/PM_{10}	107.3	20.3	0	127.6	25	Yes
SO_2	134.1	0	0	134.1	40	Yes
NO_X	314.5	0	0	314.5	40	Yes
CO	372.4	0	0	372.4	100	Yes
Ozone (VOC)	105.0	0	0.8	105.8	40	Yes
Sulfuric Acid Mist	17.6	0	0	17.6	7	Yes
Mercury	0.004	0	0	0.004	0.1	No
Lead	0.03	0	0	0.03	0.6	No
Total HAPS	8.4/18.0	0	0	8.4/18.0	10/25	No

1. Based on 6760 hours/year on natural gas at 100% output firing duct burners, 70 °F compressor inlet temperature; 1000 hours/year on oil at 100% output at 70°F compressor inlet temperature; 1000 hours/year with duct burners and power augmentation.

6.3 Control Technology

Emissions control will be primarily accomplished by good combustion of clean fuels along with the use of an SCR. The gas turbine combustors will operate in lean pre-mixed mode to minimize the flame temperature and nitrogen oxides formation potential. The SCR will control emissions of NO_X to 3.5 ppm @15% O_2 under gas-firing conditions and 10 ppmvd while oil firing. Low NO_X duct burners will be utilized between each CT and HRSG to achieve NO_X values well under the Subpart Da requirements. A full discussion is given in the Draft Best Available Control Technology (BACT) Determination (see Permit Appendix BD). The Draft BACT is incorporated into this evaluation by reference.

6.4 Air Quality Analysis

6.4.1 Air Quality Analysis Introduction

The proposed project will increase emissions of four regulated pollutants at levels in excess of PSD significant amounts: PM/PM_{10}, SO_2, NO_2, and CO. SO_2, PM_{10}, and NO_2 are criteria pollutants and have national and state ambient air quality standards (AAQS), PSD increments, and significant impact levels defined for them. CO is a criteria pollutant and has only AAQS and significant impact levels defined for it.

The applicant's initial Class II NO_2, PM_{10}, SO_2, and CO analyses predicted no significant impacts in the area surrounding the proposed facility; therefore, full impact Class II AAQS and PSD Class II increment analyses were not required for these pollutants. The nearest Class I area is the Chassahowitzka National Wildlife Refuge which is located approximately 140 km west-northwest from the project site. The applicant's PSD Class I air quality analyses showed no significant impacts; therefore cumulative impact analyses were not required in these Class I areas. Also, the maximum predicted impacts for all four pollutants were below their respective *de minimis* ambient impact levels. Therefore, pre-construction monitoring at the proposed site was not required for this project. Based on the preceding discussion, the air quality impact analyses required by the PSD regulations for this project include:

- A Class II significant impact analysis for PM_{10}, NO_2, SO_2, and CO;
- A Class I significant impact analysis for PM_{10}, NO_2, and SO_2;
- An analysis of impacts on soils, vegetation, and visibility and of growth-related air quality modeling impacts.

Based on these required analyses, the Department has reasonable assurance that the proposed project, as described in this report and subject to the conditions of approval proposed herein, will not cause or significantly contribute to a violation of any AAQS or PSD increment. However, the following EPA-directed stack height language is included: "In approving this permit, 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 if and when EPA revises 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.

6.4.2 Ambient Monitoring Requirements

Preconstruction ambient air quality monitoring is required for all pollutants subject to PSD review unless otherwise exempted or satisfied. The monitoring requirement may be satisfied by using existing representative monitoring data, if available. An exemption to the monitoring requirement may be obtained if the maximum air quality impact resulting from the projected emissions increase, as determined by air quality modeling, is less than a pollutant-specific de minimis concentration. The table below shows that predicted impacts from the combustion turbines are substantially less than the respective de minimis levels; therefore, preconstruction ambient air quality monitoring is not required for any pollutant.

Maximum Project Air Quality Impacts Compared to De Minimis Ambient Impact Levels

Pollutant	Averaging Time	Max. Predicted Impact ($\mu g/m^3$)	De Minimis Level ($\mu g/m^3$)	Impact Greater Than De Minimis?
NO_2	Annual	0.1	14	NO
CO	8-hour	14	575	NO
PM_{10}	24-hour	1	10	NO
SO_2	Annual	2	13	NO

6.4.3 Models and Meteorological Data Used in the Air Quality Analysis

6.4.3.1 PSD Class II Area Model

The EPA-approved Industrial Source Complex Short-Term (ISCST3) dispersion model determines ground-level concentrations of inert gases or small particles emitted into the atmosphere by point, area, and volume sources. The model incorporates elements for plume rise, transport by the mean wind, Gaussian dispersion, and pollutant removal mechanisms such as deposition. The ISCST3 model allows for the separation of sources, building wake downwash, and various other input and output features. 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 in each modeling scenario. Direction-specific downwash parameters were used for all sources for which downwash was considered. The stacks associated with this project will not exceed the good engineering practice (GEP) stack height criteria.

The EPA-approved Industrial Source Complex Short-Term (ISCST3) dispersion model was used to determine the maximum predicted ground-level concentration for each pollutant and applicable averaging period resulting from various operating loads, operating scenarios, fuels and ambient temperatures in the vicinity of the facility. This was accomplished by representing the generating station's proposed operating load range (i.e., 50, 75 and 100 percent loads) with a representative set of stack parameters and pollutant emission rates to produce worst-case plume dispersion conditions and highest model predicted concentrations. This process is referred to as enveloping. The representative stack parameters and emission rates for each load, fuel type and operating scenario were considered in the analysis. The EPA's land use method was used to determine whether rural or urban dispersion coefficients should be used in the ISCST3 air dispersion model. In this procedure, land circumscribed within a 3-km radius of the site was classified as rural or urban using the Auer land use classification method. Based upon a visual inspection of the USGS 7.5-minute topographic map of the generating station, it was concluded that over 50% of the area surrounding the generating station is classified as rural. Accordingly, the rural dispersion modeling option was used in the ISCST3 air dispersion modeling.

Meteorological data used in the ISCST3 model consisted of a concurrent 5-year period of hourly surface weather observations and twice-daily upper air soundings from the National Weather Service (NWS) stations at Orlando, FL and Tampa, FL. The 5-year period of meteorological data was from 1987 through 1991. These NWS stations were selected for use in the study because they are the closest primary weather stations to the study area and most representative of the project site. The surface observations included wind direction, wind speed, temperature, cloud cover, and cloud ceiling.

6.4.3.2 PSD Class I Area Model

Since the entire PSD Class I Chassahowitzka National Wildlife Refuge (CNWR) area is greater than 50 km from the proposed project, long-range transport modeling was also required for the Class I impact assessment. The California Puff (CALPUFF) dispersion model was used to evaluate the potential impact of the proposed pollutant emissions on the PSD Class I increments and on two Air Quality Related Values (AQRVs): regional haze and deposition of sulfur and nitrogen compounds. CALPUFF is a non-steady state, Lagrangian, long-range transport model that incorporates Gaussian puff dispersion algorithms. This model determines ground-level concentrations of inert gases or small particles emitted into the atmosphere by point, line, area, and volume sources. The CALPUFF model has the capability to treat time-varying sources. It is also suitable for modeling domains from tens of meters to hundreds of kilometers, and has mechanisms to handle rough or complex terrain situations. Finally, the CALPUFF model is applicable for inert pollutants as well as pollutants that are subject to linear removal and chemical conversion mechanisms.

The meteorological data used in the CALPUFF model was processed by the California Meteorological (CALMET) model. The CALMET model utilizes data from multiple meteorological stations and produces a three-dimensional modeling grid domain of hourly temperature and wind fields. The wind field is enhanced by the use of terrain data, which is also input into the model. Two-dimensional fields such as mixing heights, dispersion properties, and surface characteristics are produced by the CALMET model as well. For this project, the CALMET model produced a modeling domain centered over the project location that is approximately 290 km in the north-south direction by 350 km in the east-west direction. This modeling domain was produced by utilizing 1990 meteorological data from 1 sea surface, 3 upper air, 6 land surface, and 27 precipitation stations located throughout Florida and adjacent waters.

6.4.4 Significant Impact Analysis

In order to conduct a significant impact analysis, the applicant uses the proposed project's emissions at worst load conditions as inputs to the models. The highest predicted short-term concentrations and highest predicted annual averages predicted by this modeling are compared to the appropriate significant impact levels for the Class I and Class II Areas. If this modeling at worst load conditions shows significant impacts, additional modeling which includes the emissions from surrounding facilities is required to determine the project's impacts on the existing air quality and any applicable AAQS or PSD increments. If no significant impacts are shown, the applicant is exempted from doing any further modeling.

In order to determine the worst-case emission scenarios, the ISCST3 model in screening mode was used to assess each of the CTG/HRSG operating cases (i.e., a matrix of three CTG loads [100-, 75-, and 50-percent]; five ambient temperatures [19, 45, 60, 75 and 95°F]; and two operating modes [CTG firing natural gas and CTG firing fuel oil] for each pollutant). The worst case operating modes identified by the ISCST3 screening mode for each pollutant were then used as input for the significant impact modeling. This modeling uses ISCST3 in its regular mode. For the Class II analysis a nested rectangular grid of receptors that extends 10-km from the center of the generating station was used. The rectangular grid network consists of 100-m spacing from the center of OUC out to 3,000-m and then 500-m spacing from 3.0-km out to 10-km. Receptor spacing of 100-m intervals was used along the fenceline. The tables below show the results of the significant impact modeling for the Class II and Class I areas.

MAX PROJECT AIR QUALITY IMPACTS COMPARED TO PSD CLASS II SIGNIFICANT IMPACT LEVELS				
Pollutant	**Averaging Time**	**Max. Predicted Impact ($\mu g/m^3$)**	**Significant Impact Level ($\mu g/m^3$)**	**Significant Impact?**
PM_{10}	Annual	0.1	1	NO
	24-hr	1	5	NO
CO	8-hr	14	500	NO
	1-hr	60	2,000	NO
NO_2	Annual	0.1	1	NO
SO_2	Annual	0.1	1	NO
	3-hr	9	25	NO
	24-hr	2	5	NO

MAX PROJECT AIR QUALITY IMPACTS COMPARED TO PSD CLASS I SIGNIFICANT IMPACT LEVELS				
Chassahowitzka Pollutant	**Impact ($\mu g/m^3$)**	**Class I Increment ($\mu g/m^3$)**	**Class I SIL ($\mu g/m^3$)**	**Significant Impact?**
NO_X - Annual	0.002	2.5	0.10	NO
PM_{10} - Annual	0.001	4	0.16	NO
PM_{10} – 24 Hour	0.02	8	0.32	NO
SO_2 - Annual	0.01	2	0.08	NO
SO_2 – 3 Hour	0.31	25	1.00	NO
SO_2 – 24 Hour	0.12	5	0.20	NO

As shown in the tables there are no maximum predicted air quality impacts due to any emissions from the proposed project which are greater than the PSD significant impact levels. Therefore, under the PSD program, no further air quality impact analysis (PSD increment or AAQS analysis) is required for this project.

6.5 Additional Impacts

6.5.1 Impact Analysis Impacts On Soils, Vegetation, And Wildlife

Very low emissions are expected from these clean fuel fired combustion turbines in comparison with a conventional power plant generating equal power. Emissions of acid rain and ozone precursors will be very low. An analysis of sulfur and nitrogen deposition impacts in the CNWR was done. Based on Federal Land Manager (FLM) criteria, no adverse impacts were predicted there. The maximum ground-level concentrations predicted to occur for PM_{10}, SO_2, CO and NO_X, as a result of the proposed project, including background concentrations and all other nearby sources, will be considerably less than the respective AAQS. The project impacts are less than the significant impact levels, which in-turn are less than the applicable allowable increments for each pollutant. Because the AAQS are designed to protect both the public health and welfare and the project impacts are less than significant, it is reasonable to assume the impacts on soils, vegetation, and wildlife will be minimal or insignificant.

6.5.2 Impact On Visibility

Natural gas is a clean fuel and produces little ash. This will minimize smoke formation. The low NO_X and SO_2 emissions (as well as the very low operating hours on 0.05% sulfur oil) will minimize plume opacity. The applicant submitted visibility and regional haze analyses for the CNWR indicating impacts less than 1%. Based on FLM criteria, there will be no adverse visibility or regional haze impacts.

6.5.3 Growth-Related Air Quality Impacts

The purpose of the growth impact analysis is to quantify growth resulting from the construction and operation of the proposed project and to assess air quality impacts that would result from that growth.

Impacts associated with the facility addition and the associated ancillary equipment will be minor. While not readily quantifiable, the temporary increase in vehicular miles traveled in the area would be insignificant, as would any temporary increase in vehicular emissions.

The project is being constructed to meet general area electric power demands and, therefore, no significant secondary growth effects due to operation of the Project are anticipated. The increase in natural gas demand due to increased operation of the two affected CT's (and duct burners) will not have major impacts on local fuel markets. No significant air quality impacts due to associated industrial/commercial growth are expected.

6.5.4 Hazardous Air Pollutants

An analysis supplied by Black & Veatch indicates that the project is not a major source of hazardous air pollutants (HAPs). Although this will need to be verified through actual testing, as submitted it is not subject to any specific industry or HAP control requirements pursuant to Sections 112 of the Clean Air Act.

7. CONCLUSION

Based on the foregoing technical evaluation of the application and additional information submitted by the applicant, the Department has made a preliminary determination that the proposed project will comply with all applicable state and federal air pollution regulations, provided the Department's BACT determination is implemented.

Michael P. Halpin, P.E., Review Engineer

Cleve Holladay, Meteorologist

PERMITTEE:

OUC/KUA/FMPA/Southern Company – Florida, LLC
One Energy Place
Pensacola, FL 32520-0328

File No.	PSD-FL-313 (PA81-14SA2)
FID No.	0950137
SIC No.	4911
Expires:	December 31, 2004

Authorized Representative:

Mr. Robert G. Moore, VP of Power Generation and Transmission, Gulf Power Company

PROJECT AND LOCATION:

Permit pursuant to the requirements for the Prevention of Significant Deterioration of Air Quality (PSD Permit) for the construction of a nominal 640 megawatt (MW) Combined Cycle unit consisting of: two nominal 170 MW, General Electric "F" Class (PG7241FA) combustion turbine-electrical generators, fired with pipeline natural gas or diesel and equipped with evaporative coolers on the inlet air system; two supplementally fired heat recovery steam generators (HRSGs), each with a 160 ft. stack; one steam turbine-electrical generator rated at approximately 300 MW; one fresh water cooling tower; one distillate fuel storage tank and ancillary equipment. The combined cycle unit will achieve approximately 700 megawatts during extreme winter peaking conditions. The unit is to be installed at the existing OUC Stanton Energy Center, located at 5100 South Alafaya Trail, Orlando, Orange County. UTM coordinates are: Zone 17; 483.61 km E, 3151.1 km N.

STATEMENT OF BASIS:

This PSD 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.) and 40CFR52.21. The above named permittee is authorized to modify the facility in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department of Environmental Protection.

The attached Appendices are made a part of this permit:

Appendix GC	Construction Permit General Conditions
Appendix GG	Subpart GG, Standards of Performance for Stationary Gas Turbines
Appendix XS	Semi-Annual Continuous Emission Monitor Systems Report

Howard L. Rhodes, Director
Division of Air Resources
Management

SECTION I - FACILITY INFORMATION

FACILITY DESCRIPTION

OUC Stanton Energy Center consists of two fossil fuel fired steam electric generating stations, E.U. ID No. -001 (Unit No. 1) and -002 (Unit No. 2); also, there are storage and handling facilities for solid fuels, fly ash, limestone, gypsum, slag, and bottom ash. This project includes: two nominal 170 MW, General Electric "F" Class (PG7241FA) combustion turbine-electrical generators, fired with pipeline natural gas or diesel and equipped with evaporative coolers on the inlet air system; two supplementally fired heat recovery steam generators (HRSGs), each with a 160 ft. stack; one steam turbine-electrical generator rated at approximately 300 MW; one fresh water cooling tower; one distillate fuel storage tank and ancillary equipment.

The turbines will be equipped with Dry Low NO_X combustors as well as an SCR in order to control NO_X emissions to 3.5 ppmvd at 15% O_2 while firing natural gas. During fuel oil firing, emissions will be held to 10 ppmvd at 15% O_2 using SCR plus water injection. Pipeline quality natural gas, 0.05% sulfur oil and good combustion practices will be employed to control all pollutants.

EMISSIONS UNITS

This permit addresses the following emissions units:

EMISSION UNIT	SYSTEM	EMISSION UNIT DESCRIPTION
025	Power Generation	One nominal 170 Megawatt Gas Combustion Turbine-Electrical Generator configured as a combined cycle unit, complete with supplementary fired HRSG
026	Power Generation	One nominal 170 Megawatt Gas Combustion Turbine-Electrical Generator configured as a combined cycle unit, complete with supplementary fired HRSG
027	Water Cooling	One 10 cell Cooling Tower
028	Fuel Storage	One 1,680,000 Gallon Distillate Fuel Oil Storage Tank

REGULATORY CLASSIFICATION

The facility is classified as a Major or Title V Source of air pollution because emissions of at least one regulated air pollutant, such as particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), nitrogen oxides (NO_X), carbon monoxide (CO), or volatile organic compounds (VOC) exceeds 100 tons per year (TPY).

This facility is within an industry (fossil fuel-fired steam electric plant) included in the list of the 28 Major Facility Categories per Table 62-212.400-1, F.A.C. Because emissions are greater than 100 TPY for at least one criteria pollutant, the facility is also a Major Facility with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD). Pursuant to Table 62-212.400-2, this facility modification results in emissions increases greater than 40 TPY of SO_2 and NO_X, 25/15 TPY of PM/PM_{10}, 100 TPY of CO and 40 TPY of VOC's. These pollutants require review per the PSD rules and a determination for Best Available Control Technology (BACT) per Rule 62-212.400, F.A.C.

This project is subject to the applicable requirements of Chapter 403. Part II, F.S., Electric Power Plant and Transmission Line Siting. [Chapter 403.503 (12), F.S., Definitions]

SECTION I - FACILITY INFORMATION

Based on the Title V permit, this facility is not currently a major source of hazardous air pollutants (HAPs). This facility is subject to certain Acid Rain provisions of Title IV of the Clean Air Act.

PERMIT SCHEDULE

- xx/xx/01 PSD Permit Issued
- xx/xx/01 Site Certification Issued
- xx/xx/01 Notice of Intent to Issue PSD Permit published in xxxxxxxxxxxxx
- 05/17/01 Distributed Intent to Issue Permit
- 05/01/01 Application Complete
- 01/22/01 Received PSD Application

RELEVANT DOCUMENTS:

The documents listed below are the basis of the permit. They are specifically related to this permitting action, but are not incorporated into this permit. These documents are on file with the Department.

- Application received on January 22, 2001.
- Letter from Fish & Wildlife Service dated February 9, 2001.
- Additional information received from applicant on May 1, 2001.
- Department's Intent to Issue and Public Notice Package dated May 17, 2001.
- Department's Draft Permit and Draft BACT determination dated May 17, 2001.
- Letter from EPA Region IV dated xx/xx/01.
- Site Certification for the Stanton A Combined Cycle addition dated xx/xx/01.
- Department's Final Determination and Best Available Control Technology Determination issued concurrently with this Final Permit.

SECTION II - ADMINISTRATIVE REQUIREMENTS

GENERAL AND ADMINISTRATIVE REQUIREMENTS

1. Regulating Agencies: All documents related to applications for permits to construct, operate or modify an emissions unit should be submitted to the Bureau of Air Regulation (BAR), Florida Department of Environmental Protection (FDEP), at 2600 Blair Stone Road, Tallahassee, Florida 32399-2400 and phone number (850) 488-0114. All documents related to reports, tests, and notifications should be submitted to the DEP Central District Office, 3319 Maguire Boulevard, Suite 232, Orlando, Florida 32803-3767 and phone number 407/894-7555.
2. General Conditions: The owner and operator is subject to and shall operate under the attached General Permit Conditions G.1 through G.15 listed in Appendix GC of this permit. General Permit Conditions are binding and enforceable pursuant to Chapter 403 of the Florida Statutes. [Rule 62-4.160, F.A.C.]
3. Terminology: The terms used in this permit have specific meanings as defined in the corresponding chapters of the Florida Administrative Code.
4. Forms and Application Procedures: The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. [Rule 62-210.900, F.A.C.]
5. Modifications: The permittee shall give written notification to the Department when there is any modification to this facility. This notice shall be submitted sufficiently in advance of any critical date involved to allow sufficient time for review, discussion, and revision of plans, if necessary. Such notice shall include, but not be limited to, information describing the precise nature of the change; modifications to any emission control system; production capacity of the facility before and after the change; and the anticipated completion date of the change. [Chapters 62-210 and 62-212, F.A.C.]
6. Expiration: Approval to construct shall become invalid if construction is not commenced within 18 months after receipt of such approval, or if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified. [40 CFR 52.21(r)(2)]
7. BACT Determination: In accordance with paragraph (4) of 40 CFR 52.21 (j) and 40 CFR 51.166(j), the Best Available Control Technology (BACT) determination shall be reviewed and modified as appropriate in the event of a plant conversion. This paragraph states: "For phased construction projects, the determination of best available control technology shall be reviewed and modified as appropriate at the latest reasonable time which occurs no later than 18 months prior to commencement of construction of each independent phase of the project. At such time, the owner or operator of the applicable stationary source may be required to demonstrate the adequacy of any previous determination of best available control technology for the source." This reassessment will also be conducted for this project if there are any increases in heat input limits, hours of operation, oil firing, low or baseload operation, short-term or annual emission limits, annual fuel heat input limits or similar changes. [40 CFR 52.21(j), 40 CFR 51.166(j) and Rule 62-4.070 F.A.C.]
8. Permit Extension: The permittee, for good cause, may request that this PSD permit be extended. Such a request shall be submitted to the Bureau of Air Regulation prior to 60 days before the expiration of the permit. In conjunction with extension of the 18-month periods to commence or continue construction, or extension of the December 31, 2004 permit expiration date, the permittee may be required to demonstrate the adequacy of any previous determination of best available control technology for the source. [Rule 62-4.080, F.A.C.]

9. Application for Title IV Permit: An application for a Title IV Acid Rain Permit, must be submitted to the U.S. Environmental Protection Agency Region IV office in Atlanta, Georgia and a copy to the DEP's Bureau of Air Regulation in Tallahassee 24 months before the date on which the new unit begins serving an electrical generator (greater than 25 MW). [40 CFR 72]

10. Application for Title V Permit: An application for a Title V operating permit, pursuant to Chapter 62-213, F.A.C., must be submitted to the DEP's Bureau of Air Regulation, and a copy to the Department's Central District Office. [Chapter 62-213, F.A.C.]

11. New or Additional Conditions: Pursuant to Rule 62-4.080, F.A.C., 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.]

12. Annual Reports: Pursuant to Rule 62-210.370(2), F.A.C., Annual Operation Reports, the permittee is required to submit annual reports on the actual operating rates and emissions from this facility. Annual operating reports shall be sent to the DEP's Central District Office by March 1st of each year.

13. Stack Testing Facilities: Stack sampling facilities shall be installed in accordance with Rule 62-297.310(6), F.A.C.

14. Quarterly Reports: Quarterly excess emission reports, in accordance with 40 CFR 60.7 (a)(7) (c) (1998 version), shall be submitted to the DEP's Central District Office.

APPLICABLE STANDARDS AND REGULATIONS

1. Unless otherwise indicated in this permit, the construction and operation of the subject emission unit(s) 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 Florida Administrative Code Chapters 62-4, 62-17, 62-204, 62-210, 62-212, 62-213, 62-214, 62-296, and 62-297; and the applicable requirements of the Code of Federal Regulations Section 40, Parts 52, 60, 72, 73, and 75.

2. NSPS Requirements: Each combustion turbine (CT) shall comply with all applicable requirements of 40 CFR 60, adopted by reference in Rule 62-204.800(7)(b), F.A.C.

   a. **Subpart A, General Provisions**, including: 40 CFR 60.7 (Notification and Record Keeping), 40 CFR 60.8 (Performance Tests), 40 CFR 60.11 (Compliance with Standards and Maintenance Requirements), 40 CFR 60.12 (Circumvention), 40 CFR 60.13 (Monitoring Requirements), and 40 CFR 60.19 (General Notification and Reporting Requirements).

   b. **Subpart GG, Standards of Performance for Stationary Gas Turbines;** see attached *Appendix GG.*

3. Issuance of this permit does not relieve the facility owner or operator from compliance with any applicable federal, state, or local permitting requirements or regulations. [Rule 62-210.300, F.A.C.]

4. These emission units shall comply with all applicable requirements of 40CFR60, Subpart A, General Provisions including:

   - 40CFR60.7, Notification and Recordkeeping
   - 40CFR60.8, Performance Tests
   - 40CFR60.11, Compliance with Standards and Maintenance Requirements
   - 40CFR60.12, Circumvention
   - 40CFR60.13, Monitoring Requirements
   - 40CFR60.19, General Notification and Reporting requirements

5. ARMS Emissions Units 025 and 026. Direct Power Generation, each consisting of a nominal 170 megawatt combustion turbine-electrical generator, shall comply with all applicable provisions of 40CFR60, Subpart GG, Standards of Performance for Stationary Gas Turbines, adopted by reference in Rule 62-204.800(7)(b), F.A.C. The Subpart GG requirement to correct test data to ISO conditions applies. However, such correction is not used for compliance determinations with the BACT standard(s). Additionally, each Emissions Unit consists of a supplementally fired heat recovery steam generator equipped with a natural gas fired 533 MMBTU/hr duct burner (LHV) and combined with a nominal 300 MW steam electrical generators. These shall comply with all applicable provisions of 40CFR60, Subpart Da, Standards of Performance for Electric Utility Steam Generating Units Which Construction is Commenced After September 18, 1978, adopted by reference in Rule 62-204.800(7), F.A.C.

6. ARMS Emission Unit 027. Cooling Tower, an unregulated emission unit. The Cooling Tower is not subject to a NESHAP because chromium-based chemical treatment is not used.

7. ARMS Emission Unit 028. Fuel Storage Tank, consisting of a 1,680,000 gallon distillate fuel storage tank. The storage tank is subject to 40 CFR 60, Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels (including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction or Modification Commenced After July 23, 1984.

8. All notifications and reports required by the above specific conditions shall be submitted to the DEP's Central District Office.

GENERAL OPERATION REQUIREMENTS

9. Fuels: Only pipeline natural gas or (up to) 1000 hours per year of 0.05% distillate fuel oil shall be fired in each CT emissions unit. Only natural gas shall be fired in each duct burner. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

10. Combustion Turbine Capacity: The maximum heat input rates to each CT/HRSG shall not exceed 2,402 million Btu per hour (MMBtu/hr) when firing natural gas with duct burner firing and power augmentation. The maximum heat input rates to each CT/HRSG shall not exceed 2,068 million Btu per hour (MMBtu/hr) when firing fuel oil. These maximum heat input rates shall not be exceeded under any condition, regardless of ambient conditions or combustion turbine characteristics. Manufacturer's curves corrected for ISO conditions shall be provided to the Department of Environmental Protection (DEP) within 45 days of completing the initial compliance testing. [Design, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

11. Heat Recovery Steam Generator equipped with Duct Burner. The maximum heat input rate of the natural gas fired duct burner shall not exceed 533 MMBtu/hour (LHV) at any temperature or under any scenario. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

12. 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.

13. 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 owner or operator shall notify the DEP Central District office as soon as possible, but at least within (1) working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; the 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 and the regulations. [Rule 62-4.130, F.A.C.]

14. Operating Procedures: Operating procedures shall include good operating practices and proper training of all operators and supervisors. The good operating practices shall meet the guidelines and procedures as established by the equipment manufacturers. All operators (including supervisors) of air pollution control devices shall be properly trained in plant specific equipment. [Rule 62-4.070(3), F.A.C.]

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

16. Maximum allowable hours of operation for each CT/HRSG Emissions Unit are 8760 hours per year while firing natural gas. Fuel oil firing is permitted for 1000 hours during any consecutive 12-month period in each CT. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

17. Simple Cycle Operation: The plant may not be operated without the use of the SCR system except during periods of startup and shutdown.

CONTROL TECHNOLOGY

18. Dry Low NO_X (DLN) combustors and water injection capability shall be installed on each stationary combustion turbine. The permittee shall install a selective catalytic reduction system to comply with the NO_X and ammonia limits listed in Specific Condition 21. Additionally, space shall be provided for the installation of oxidation catalysts. [Design, Rules 62-4.070 and 62-212.400, F.A.C.]

19. The permittee shall design these units to accommodate adequate testing and sampling locations for compliance with the applicable emission limits (per each unit) listed in Specific Conditions No. 21 through 25. [Rule 62-4.070 , Rule 62-204.800, F.A.C., and 40 CFR60.40a(b)]

20. Drift eliminators shall be installed on the cooling tower to reduce PM/PM_{10} emissions. A certification following installation (and prior to startup) shall be submitted that the drift eliminators were installed and that the installation is capable of meeting 0.002-gallons/100 gallons recirculation water flowrate.

EMISSION LIMITS AND STANDARDS

21. Nitrogen Oxides (NO_X) Emissions:

- The concentration of NO_X in the stack exhaust gas, with the combustion turbine operating on natural gas shall not exceed 3.5 ppmvd @15% O_2 on a 3-hr block average. This limit shall apply whether or not the unit is operating with duct burner on and/or in power augmentation mode. Compliance shall be determined by the continuous emission monitor (CEMS). [BACT Determination]
- The emissions of NO_X in the stack exhaust gas, with the combustion turbine operating on fuel oil shall not exceed 10.0 ppmvd @15% O_2 on a 3-hr block average. Compliance shall be determined by the continuous emission monitor (CEMS). [BACT Determination]
- Emissions of NO_X from the duct burner shall not exceed 0.1 lb/MMBtu, which is more stringent than the NSPS (see Specific Condition 30 for compliance procedures). [Applicant Request, Rule 62-4.070 and 62-204.800(7), F.A.C.]
- The concentration of ammonia in the exhaust gas from each CT/HRSG shall not exceed 5.0 ppmvd @15% O_2. The compliance procedures are described in Specific Conditions 29 and 45. [BACT, Rules 62-212.400 and 62-4.070, F.A.C.]

22. Carbon Monoxide (CO) Emissions: Emissions of CO in the stack exhaust gas (at ISO conditions) with the combustion turbine operating on natural gas shall not exceed 17 ppmvd @15% O_2 on a 24-hr block average to be demonstrated by CEMS; and neither 14 ppmvd @15% O_2 with the CT operating on fuel oil on a 24-hr block average to be demonstrated by CEMS. These limits shall also be demonstrated by annual stack test using EPA Method 10 or through annual RATA testing. Within 24 months of the date of completion of initial testing, the applicant shall either have installed oxidation catalyst in each CT/HRSG or forfeit its right to do so with the pre-determined (BACT) emission limits specified below. [BACT, Rule 62-212.400, F.A.C.]

- In the event that an oxidation catalyst is installed for any reason in either CT/HRSG pair within 24 months of the date of completion of initial testing, the limits for CO and VOC shall be 5 ppmvd and 3 ppmvd (respectively) to be demonstrated by stack testing during power augmentation and duct burner firing (I, A). [BACT]

23. Volatile Organic Compounds (VOC) Emissions: Emissions of VOC in the stack exhaust gas (baseload at ISO conditions) with the combustion turbine operating on gas shall exceed neither 2.7 ppmvd @15% O_2 with the CT firing fuel oil and neither 6.3 ppmvd @15% O_2 with the CT firing natural gas (with maximum duct burner firing and operating in power augmentation mode); to be demonstrated by initial stack tests using EPA Method 18, 25 or 25A. [BACT, Rule 62-212.400, F.A.C.]

24. Sulfur Dioxide (SO_2) emissions: SO_2 emissions shall be limited by firing pipeline natural gas (sulfur content not greater than 1.5 grains per 100 standard cubic foot) and up to 1000 hours per consecutive 12-month period of 0.05% sulfur fuel oil. Compliance with these fuel limits in conjunction with implementation of the attached Appendix GG will demonstrate compliance with the applicable NSPS SO_2 emissions limitations from the duct burner and the combustion turbine. Note: This will effectively limit the combined SO_2 emissions for EU-025 and EU-026 to approximately 134 tons per year. [BACT, 40CFR60 Subpart GG and Rules 62-4.070, 62-212.400, and 62-204.800(7), F.A.C.]

25. PM/PM_{10} and Visible emissions (VE): VE emissions shall not exceed 10 percent opacity from the stack in use. [BACT, Rules 62-4.070, 62-212.400, and 62-204.800(7), F.A.C.]

EXCESS EMISSIONS

26. Excess emissions resulting from startup, shutdown, or malfunction shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized. Excess emissions occurrences shall in no case exceed two hours in any 24-hour period except during a "cold start-up" to combined cycle plant operation. During cold start-up to combined cycle operation, up to four hours of excess emissions are allowed. Cold start-up is defined as a startup to combined cycle operation following a complete shutdown lasting at least 72 hours. Operation below 50% output per turbine shall otherwise be limited to 2 hours in any 24-hour period. [BACT, Rule 62-210.700, F.A.C.].

27. Excess emissions 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 pursuant to Rule 62-210.700, F.A.C. These emissions shall be included in the 3-hr average for NO_X and the 24-hr average for CO.

28. Excess Emissions Report: If excess emissions occur for more than two hours due to malfunction, the owner or operator shall notify DEP's Central District office within (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident. Pursuant to the New Source Performance Standards, all excess emissions shall also be reported in accordance with 40 CFR 60.7, Subpart A. Following this format, 40 CFR 60.7, and using the monitoring methods listed in Specific Conditions 41 through 45, periods of startup, shutdown, malfunction, shall be monitored, recorded, and reported as excess emissions when emission levels exceed the permitted standards listed in Specific Condition No. 21 through 25. [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C., and 40 CFR 60.7 (1998 version)].

COMPLIANCE DETERMINATION

29. Compliance with the allowable emission limiting standards shall be determined within 60 days after achieving the maximum production rate, but not later than 180 days of initial operation of the unit, and annually thereafter as indicated in this permit, by using the following reference methods as described in 40 CFR 60, Appendix A (1998 version), and adopted by reference in Chapter 62-204.800, F.A.C.

30. Initial (I) performance tests shall be performed by the deadlines in Specific Condition 29. Initial tests shall also be conducted after any replacement of the major components of the air pollution control equipment (and shake down period not to exceed 100 days after re-starting the CT), such as replacement of SCR catalyst or addition of oxidation catalyst (or change of combustors, if specifically requested by the DEP on a case-by-case basis). Annual (A) compliance tests shall be performed during every federal fiscal year (October 1 - September 30) pursuant to Rule 62-297.310(7), F.A.C., on these units as indicated. The following reference methods shall be used. No other test methods may be used for compliance testing unless prior DEP approval is received in writing. Where initial tests only are indicated, these tests shall be repeated prior to renewal of each operation permit.

- EPA Reference Method 9, "Visual Determination of the Opacity of Emissions from Stationary Sources" (I, A).
- EPA Reference Method 10, "Determination of Carbon Monoxide Emissions from Stationary Sources" (I, A).
- EPA Reference Method 20, "Determination of Oxides of Nitrogen Oxide, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines" (EPA reference Method 7E, "Determination of Nitrogen Oxides Emissions from Stationary Sources" or RATA test data may be used to demonstrate compliance for annual test requirement) shall be conducted a) while firing natural gas with maximum duct burner heat input as well as maximum power augmentation and b) while firing fuel oil at the maximum heat input; Initial test for compliance with 40CFR60 Subpart GG; Initial (only) NO_X compliance test for the duct burners (Subpart Da) shall be accomplished via testing with duct burners "on" as compared to "off" and computing the difference.
- EPA Reference Method 18, 25 and/or 25A, "Determination of Volatile Organic Concentrations." Initial test only.
- EPA Method 0011 or CARB Method 430 shall be utilized to evaluate the emissions of formaldehydes on each CT/Duct Burner as per the table below. A full report including all test results, analyses and applicant's MACT Determination shall be forwarded to the Bureau of Air Regulation in Tallahassee within the same time constraints identified in Specific Condition 29.

OPERATING MODE	TEST PROTOCOL	TPY CALCULATION
Maximum CT output Natural Gas; Duct Burner firing at maximum output	CARB Method 430 or EPA Method 0011	(6760/2000) times measured Lb/Hour Formaldehyde
Maximum CT output Natural Gas; Duct Burner firing and Power Augmentation implemented, both at max. output	CARB Method 430 or EPA Method 0011	(1000/2000) times measured Lb/Hour Formaldehyde
Maximum output, Fuel Oil	CARB Method 430 or EPA Method 0011	(1000/2000) times measured Lb/Hour Formaldehyde

Note: Results of the sampling method(s) identified above shall be blank corrected. For Method 0011, a minimum sample volume of 30 cubic feet shall be collected. To improve test precision, there shall be two co-located trains for each test. A minimum of 3 runs per CT/Duct Burner shall constitute a test.

- Method CTM-027 for ammonia slip (I, A) to be completed simultaneously with NO_X compliance testing.

The applicant shall calculate and report the ppmvd ammonia slip (@ 15% O_2) at the measured lb/hr NO_X emission rate as a means of compliance with the BACT standard. The applicant shall also be capable of calculating ammonia slip at the Department's request, according to Specific Condition 45.

31. Continuous compliance with the CO and NO_X emission limits: Continuous compliance with the CO and NO_X emission limits shall be demonstrated by the CEM system on the specified hour average basis. Based on CEMS data, a separate compliance determination is conducted at the end of each period and a new average emission rate is calculated from the arithmetic average of all valid hourly emission rates from the previous period. Specific Condition 41 further describes the CEM system requirements. Excess emissions periods shall be reported as required in Condition 28. [Rules 62-4.070 F.A.C., 62-210.700, F.A.C., 40 CFR 75 and BACT]

32. Compliance with the SO_2 and PM/PM_{10} emission limits: For the purposes of demonstrating compliance with the 40 CFR 60.333 SO_2 standard, the applicant is responsible for ensuring that the procedures outlined in attached Appendix GG are complied with.

33. Compliance with CO emission limit: An initial and annual test for CO shall be conducted at 100% capacity with the duct burners off. The NO_X and CO test results shall be the average of three valid one-hour runs. Annual RATA testing for the CO and NO_X CEMS shall be required pursuant to 40 CFR 75.

34. Compliance with the VOC emission limit: An initial test is required to demonstrate compliance with the VOC emission limit. Thereafter, the CO emission limit will be employed as a surrogate and no annual testing is required [see Specific Condition 22 for exception].

35. Testing procedures: Unless otherwise specified, testing of emissions shall be conducted with the combustion turbine operating at permitted capacity. Permitted capacity is defined as 90-100 percent of the maximum heat input rate allowed by the permit, corrected for the average ambient air temperature during the test (with 100 percent represented by a curve depicting heat input vs. ambient temperature). Procedures for these tests shall meet all applicable requirements (i.e., testing time frequency, minimum compliance duration, etc.) of Chapters 62-204 and 62-297, F.A.C.

36. Test Notification: The DEP's Central District office shall be notified, in writing, at least 30 days prior to the initial performance tests and at least 15 days before annual compliance tests.

37. Special Compliance Tests: The DEP may request a special compliance test pursuant to Rule 62-297.310(7), F.A.C., when, after investigation (such as complaints, increased visible emissions, odors or questionable maintenance of control equipment), there is reason to believe that any applicable emission standard is being violated.

38. Test Results: Compliance test results shall be submitted to the DEP's Central District office no later than 45 days after completion of the last test run. [Rule 62-297.310(8), F.A.C.].

NOTIFICATION, REPORTING, AND RECORDKEEPING

39. Records: All measurements, records, and other data required to be maintained by the applicant shall be recorded in a permanent form and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. These records shall be made available to DEP representatives upon request.

   - The applicant will be required to maintain records indicating the daily hours of operation of each CT/HRSG unit. These records shall specify which type of fuel is being combusted and the records shall be available for review at the site. Each calendar month, a compilation of the hours of operation for each CT/HRSG unit combusting fuel oil shall be made and totalized for the most recent consecutive 12-month period. Each AOR submitted by the applicant shall include a compilation of each consecutive 12-month period during the preceding calendar year.

40. Compliance Test Reports: The test report shall provide sufficient detail on the tested emission unit and the procedures used to allow the Department to determine if the test was properly conducted and if the test results were properly computed. At a minimum, the test report shall provide the applicable information listed in Rule 62-297.310(8), F.A.C.

MONITORING REQUIREMENTS

41. Continuous Monitoring System: The permittee shall install, calibrate, maintain, and operate a continuous emission monitor in the stack to measure and record the emissions of NO_X and CO from these emissions units, and the Carbon Dioxide (CO_2) content of the flue gas at the location where NO_X and CO are monitored, in a manner sufficient to demonstrate compliance with the emission limits of this permit. The CEM system shall be used to demonstrate compliance with the emission limits for NO_X and CO established in this permit. Compliance with the emission limits for NOx shall be based on a 3-hour block average. The 3-hour block average shall be calculated from 3 consecutive hourly average emission rate values. Compliance with the emission limits for CO shall be based on a 24-hour block average starting at midnight of each operating day. The 24-hour block average shall be calculated from 24 consecutive hourly average emission rate values. Each hourly value shall be computed using at least one data point in each fifteen-minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, an hourly value shall be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour). The owner or operator shall use all valid measurements or data points collected during an hour to calculate the hourly averages. All data points collected during an hour shall be, to the extent practicable, evenly spaced over the hour. If the CEM system measures concentration on a wet basis, the CEM system shall include provisions to determine the moisture content of the exhaust gas and an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Alternatively, the owner or operator may develop through manual stack test measurements a curve of moisture contents in the exhaust gas versus load for each allowable fuel, and use these typical values in an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Final results of the CEM system shall be expressed as ppmvd, corrected to 15% oxygen.

The NO_X monitor shall be certified and operated in accordance with the following requirements. The NO_X monitor shall be certified pursuant to 40 CFR Part 75 and shall be operated and maintained in accordance with the applicable requirements of 40 CFR Part 75, Subparts B and C. For purposes of determining compliance with the emission limits specified within this permit, missing data shall not be substituted. Instead the block average shall be determined using the remaining hourly data in the 3-hour block. Record keeping and reporting shall be conducted pursuant to 40 CFR Part 75, Subparts F and G. The RATA tests required for the NO_X monitor shall be performed using EPA Method 20 or 7E, of Appendix A of 40 CFR 60. The NO_X monitor shall be a dual range monitor. The span for the lower range shall not be greater than 10 ppm, and the span for the upper range shall not be greater than 30 ppm, as corrected to 15% O_2.

The CO monitor and CO_2 monitor shall be certified and operated in accordance with the following requirements. The CO monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4. The CO_2 monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 3. 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 semi-annually to the Department's Central District Office. The RATA tests required for the CO monitor shall be performed using EPA Method 10, of Appendix A of 40 CFR 60. The Method 10 analysis shall be based on a continuous sampling train, and the ascarite trap may be omitted or the interference trap of section 10.1 may be used in lieu of the silica gel and ascarite traps. The CO monitor shall be a dual range monitor. The span for the lower range shall not be greater than 20 ppm, and the span for the upper range shall not be greater than 100 ppm, as corrected to 15% O_2. The RATA tests required for the CO_2 monitor shall be performed using EPA Method 3B, of Appendix A of 40 CFR 60.

NO_X, CO and CO_2 emissions data shall be recorded by the CEM system during episodes of startup, shutdown and malfunction. NO_X and CO emissions data recorded during these episodes may be excluded from the block average calculated to demonstrate compliance with the emission limits specified within this permit. Periods of data excluded for startup shall not exceed two hours in any block 24-hour period except for "cold startup." A cold startup is defined as a startup following a complete shutdown lasting a minimum of 72 hours. Periods of data excluded for cold startup shall not exceed four hours in any 24-hour block period. Periods of data excluded for shutdown shall not exceed two hours in any 24-hour block period. Periods of data excluded for malfunctions shall not exceed two hours in any 24-hour block period. All periods of data excluded for any startup, shutdown or malfunction episode shall be consecutive for each episode. Periods of data excluded for all startup, shutdown or malfunction episodes shall not exceed four hours in any 24-hour block period. The owner or operator shall minimize the duration of data excluded for startup, shutdown and malfunctions, to the extent practicable. Data recorded during startup, shutdown or malfunction events shall not be excluded if the startup, shutdown or malfunction episode was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented.

Best operational practices shall be used to minimize hourly emissions that occur during episodes of startup, shutdown and malfunction. Emissions of any quantity or duration that occur entirely or in part from poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented, shall be prohibited.

A summary report of duration of data excluded from the block average calculation, and all instances of missing data from monitor downtime, shall be reported to the Department's Central District office semi-annually, and shall be consolidated with the report required pursuant to 40 CFR 60.7. For purposes of reporting "excess emissions" pursuant to the requirements of 40 CFR 60.7, excess emissions shall be defined as the hourly emissions which are recorded by the CEM system during periods of data excluded for episodes of startup, shutdown and malfunction, allowed above. The duration of excess emissions shall be the duration of the periods of data excluded for such episodes. Reports required by this paragraph and by 40 CFR 60.7 shall be submitted no less than semi-annually, including semi-annual periods in which no data is excluded or no instances of missing data occur. Upon request from the Department, the CEMS emission rates shall be corrected to ISO conditions to demonstrate compliance with the applicable standards of 40 CFR 60.332. [Rules 62-4.070(3) and 62-212.400., F.A.C., and BACT]

[Note: Compliance with these requirements will ensure compliance with the other CEM system requirements of this permit to comply with Subpart GG requirements, as well as the applicable requirements of Rule 62-297.520, F.A.C., 40 CFR 60.7(a)(5) and 40 CFR 60.13, and with 40 CFR Part 51, Appendix P, 40 CFR 60, Appendix B, Performance Specifications and 40 CFR 60, Appendix F, Quality Assurance Procedures].

42. Continuous Monitoring System Reports: The monitoring devices shall comply with the certification and quality assurance, and any other applicable requirements of Rule 62-297.520, F.A.C., 40 CFR 60.13, including certification of each device in accordance with 40 CFR 60, Appendix B, Performance Specifications and 40 CFR 60.7(a)(5) or 40 CFR Part 75. Quality assurance procedures must conform to all applicable sections of 40 CFR 60, Appendix F or 40CFR75. The monitoring plan, consisting of data on CEM equipment specifications, manufacturer, type, calibration and maintenance needs, and its proposed location shall be provided to the DEP Bureau of Ambient Monitoring & Mobile Sources (BAMMS) as well as the EPA for review no later than 45 days prior to the first scheduled certification test pursuant to 40 CFR 75.62.

43. Determination of Process Variables:

- The permittee shall operate and maintain equipment and/or instruments necessary to determine process variables, such as process weight input or heat input, when such data is needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards. No later than 90 days prior to operation, the permittee shall submit for the Department's approval a list of process variables that will be measured to comply with this permit condition.
- Equipment and/or instruments used to directly or indirectly determine such process variables, including devices such as belt scales, weigh 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]

44. Subpart Da Monitoring and Recordkeeping Requirements: The permittee shall comply with all applicable requirements of this Subpart [40CFR60, Subpart Da].

45. Selective Catalytic Reduction System (SCR) Compliance Procedures:

- An annual stack emission test for nitrogen oxides and ammonia from the CT/HRSG pair shall be simultaneously conducted while operating in the power augmentation mode with the duct burner on as defined in Specific Condition 21. The ammonia injection rate necessary to comply with the NO_X standard shall be established and reported during the each performance test.
- The SCR shall operate at all times that the turbine is operating, except during turbine start-up and shutdown periods, as dictated by manufacturer's guidelines and in accordance with this permit.
- The permittee shall install and operate an ammonia flow meter to measure and record the ammonia injection rate to the SCR system of the CT/HRSG set. It shall be maintained and calibrated according to the manufacturer's specifications.
- During the stack test, the permittee (at each tested load condition) shall determine and report the ammonia flow rate required to meet the emissions limitations. During NO_X CEM downtimes or malfunctions, the permittee shall operate at the ammonia flow rate, which was established during the last stack test.
- Ammonia emissions shall be calculated continuously using inlet and outlet NO_X concentrations from the SCR system and ammonia flow supplied to the SCR system. The calculation procedure shall be provided with the CEM monitoring plan required by 40CFR Part 75. The following

calculation represents one means by which the permittee may demonstrate compliance with this condition:

Ammonia slip @ 15% O_2 = (A-(BxC/1,000,000)) x (1,000,000/B) x D, where:
A= ammonia injection rate (lb/hr)/ 17 (lb/lb.mol)
B = dry gas exhaust flow rate (lb/hr) / 29 (lb/lb.mol)
C = change in measured NO_X (ppmv@15% O_2) across catalyst
D = correction factor, derived annually during compliance testing by comparing actual to tested ammonia slip

- The calculation along with each newly determined correction factor shall be submitted with each annual compliance test. Calibration data ("as found" and "as left") shall be provided for each measurement device utilized to make the ammonia emission measurement and submitted with each annual compliance test.
- Upon specific request by the Department, a special re-test shall occur as described in the previous conditions concerning annual test requirements, in order to demonstrate that all NO_X and ammonia slip related permit limits can be complied with.

NSPS SUBPART GG REQUIREMENTS FOR GAS TURBINES

NSPS SUBPART GG REQUIREMENTS

[Note: Inapplicable provisions have been deleted in the following conditions, but the numbering of the original rules has been preserved for ease of reference to the original rules. The term "Administrator" when used in 40 CFR 60 shall mean the Department's Secretary or the Secretary's designee. Department notes and requirements related to the Subpart GG requirements are shown in **bold** immediately following the section to which they refer. The rule basis for the Department requirements specified below is Rule 62-4.070(3), F.A.C.]

Pursuant to 40 CFR 60.332 Standard for Nitrogen Oxides:

(a) On and after the date of the performance test required by § 60.8 is completed, every owner or operator subject to the provisions of this subpart as specified in paragraph (b) section shall comply with:

(1) No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine, any gases which contain nitrogen oxides in excess of:

$$STD = 0.0075 \frac{(14.4)}{Y} + F$$

where:

STD = allowable NOx emissions (percent by volume at 15 percent oxygen and on a dry basis).

Y = manufacturer's rated heat rate at manufacturer's rated load (kilojoules per watt hour) or, actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt-hour.

F = NOx emission allowance for fuel-bound nitrogen as defined in paragraph (a)(3) of this section.

(3) F shall be defined according to the nitrogen content of the fuel as follows:

Fuel-bound nitrogen (percent by weight)	F (NOx percent by volume)
$N \leq 0.015$	0
$0.015 < N \leq 0.1$	0.04(N)
$0.1 < N \leq 0.25$	0.004+0.0067(N–0.1)
$N > 0.25$	0.005

Where, N = the nitrogen content of the fuel (percent by weight).

Department requirement: While firing gas, the "F" value shall be assumed to be 0.

[Note: This is required by EPA's March 12, 1993 determination regarding the use of NOx CEMS. The "Y" values are approximately 10.0 for natural gas and 10.6 for fuel oil. The equivalent emission standards are 108 and 102 ppmvd at 15% oxygen. The emissions standards of this permit are more stringent than this requirement.]

(b) Electric utility stationary gas turbines with a heat input at peak load greater than 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired shall comply with the provisions of paragraph (a)(1) of this section.

SECTION IV. APPENDIX GG

NSPS SUBPART GG REQUIREMENTS FOR GAS TURBINES

Pursuant to 40 CFR 60.333 Standard for Sulfur Dioxide:

On and after the date on which the performance test required to be conducted by 40 CFR 60.8 is completed, every owner or operator subject to the provision of this subpart shall comply with:

(b) No owner or operator subject to the provisions of this subpart shall burn in any stationary gas turbine any fuel, which contains sulfur in excess of 0.8 percent by weight.

Pursuant to 40 CFR 60.334 Monitoring of Operations:

(b) The owner or operator of any stationary gas turbine subject to the provisions of this subpart shall monitor sulfur content and nitrogen content of the fuel being fired in the turbine. The frequency of determination of these values shall be as follows:

(1) If the turbine is supplied its fuel from a bulk storage tank, the values shall be determined on each occasion that fuel is transferred to the storage tank from any other source.

Department requirement: The owner or operator is allowed to use vendor analyses of the fuel as received to satisfy the sulfur content monitoring requirements of this rule for fuel oil. Alternatively, if the fuel oil storage tank is isolated from the combustion turbines while being filled, the owner or operator is allowed to determine the sulfur content of the tank after completion of filling of the tank, before it is placed back into service.

[Note: This is consistent with guidance from EPA Region 4 dated May 26, 2000 to Ronald W. Gore of the Alabama Department of Environmental Management.]

(2) If the turbine is supplied its fuel without intermediate bulk storage the values shall be determined and recorded daily. Owners, operators or fuel vendors may develop custom schedules for determination of the values based on the design and operation of the affected facility and the characteristics of the fuel supply. These custom schedules shall be substantiated with data and must be approved by the Administrator before they can be used to comply with paragraph (b) of this section.

(1) Department requirement: The requirement to monitor the nitrogen content of pipeline quality natural gas fired is waived. The requirement to monitor the nitrogen content of fuel oil fired is waived because a NOx CEMS shall be used to demonstrate compliance with the NOx limits of this permit. For purposes of complying with the sulfur content monitoring requirements of this rule, the owner or operator shall obtain a monthly report from the vendor indicating the sulfur content of the natural gas being supplied from the pipeline for each month of operation.

(2) [Note: This is consistent with EPA's custom fuel monitoring policy and guidance from EPA Region 4.]

(c) For the purpose of reports required under 40 CFR 60.7(c), periods of excess emissions that shall be reported are defined as follows:

(1) *Nitrogen oxides.* Any one-hour period during which the average water-to-fuel ratio, as measured by the continuous monitoring system, falls below the water-to-fuel ratio determined to demonstrate compliance with 40 CFR 60.332 by the performance test required in § 60.8 or any period during which the fuel-bound nitrogen of the fuel is greater than the maximum nitrogen content allowed by the fuel-bound nitrogen allowance used during the performance test required in § 60.8. Each report shall include the average water-to-fuel ratio, average fuel consumption, ambient conditions, gas turbine load, and nitrogen content of the fuel during the period of excess emissions, and the graphs or figures developed under 40 CFR 60.335(a).

Department requirement: NOx emissions monitoring by CEM system shall substitute for the requirements of paragraph (c)(1) because a NOx monitor is required to demonstrate compliance with the standards of this permit. Data from the NOx monitor shall be used to determine "excess emissions" for purposes of 40 CFR 60.7 subject to the conditions of the permit.

[Note: This is consistent with guidance from EPA Region 4 dated May 26, 2000 to Ronald W. Gore of the Alabama Department of Environmental Management.]

(2) *Sulfur dioxide.* Any daily period during which the sulfur content of the fuel being fired in the gas turbine exceeds 0.8 percent.

Pursuant to 40 CFR 60.335 Test Methods and Procedures:

(a) To compute the nitrogen oxides emissions, the owner or operator shall use analytical methods and procedures that are accurate to within 5 per-cent and are approved by the Administrator to determine the nitrogen content of the fuel being fired.

(b) In conducting the performance tests required in 40 CFR 60.8, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided for in 40 CFR 60.8(b). Acceptable alternative methods and procedures are given in paragraph (f) of this section.

(c) The owner or operator shall determine compliance with the nitrogen oxides and sulfur dioxide standards in 40 CFR 60.332 and 60.333(a) as follows:

(1) The nitrogen oxides emission rate (NOx) shall be computed for each run using the following equation:

$$NOx = (NOxo)\,(Pr/Po)^{0.5}\,e^{19(Ho-0.00633)}\,(288°K/Ta)^{1.53}$$

where:

NOx	=	emission rate of NOx at 15 percent O2 and ISO standard ambient conditions, volume percent.
NOxo	=	observed NOx concentration, ppm by volume.
Pr	=	reference combustor inlet absolute pressure at 101.3 kilopascals ambient pressure, mm Hg.
Po	=	observed combustor inlet absolute pressure at test, mm Hg.
Ho	=	observed humidity of ambient air, g H2O/g air.
e	=	transcendental constant, 2.718.
Ta	=	ambient temperature, °K.

Department requirement: The owner or operator is not required to have the NOx monitor continuously correct NOx emissions concentrations to ISO conditions. However, the owner or operator shall keep records of the data needed to make the correction, and shall make the correction when required by the Department or Administrator.

[Note: This is consistent with guidance from EPA Region 4.]

(2) The monitoring device of 40 CFR 60.334(a) shall be used to determine the fuel consumption and the water-to-fuel ratio necessary to comply with 40 CFR 60.332 at 30, 50, 75, and 100 percent of peak load or at four points in the normal operating range of the gas turbine, including the

minimum point in the range and peak load. All loads shall be corrected to ISO conditions using the appropriate equations supplied by the manufacturer.

Department requirement: The owner or operator is allowed to conduct initial performance tests at a single load because a NOx monitor shall be used to demonstrate compliance with the BACT NOx limits of this permit.

[Note: This is consistent with guidance from EPA Region 4.]

(3) Method 20 shall be used to determine the nitrogen oxides, sulfur dioxide, and oxygen concentrations. The span values shall be 300 ppm of nitrogen oxide and 21 percent oxygen. The NOx emissions shall be determined at each of the load conditions specified in paragraph (c)(2) of this section.

Department requirement: The owner or operator is allowed to make the initial compliance demonstration for NOx emissions using certified CEM system data, provided that compliance be based on a minimum of three test runs representing a total of at least three hours of data, and that the CEMS be calibrated in accordance with the procedure in section 6.2.3 of Method 20 following each run. Alternatively, initial compliance may be demonstrated using data collected during the initial relative accuracy test audit (RATA) performed on the NOx monitor. The span value specified in the permit shall be used instead of that specified in paragraph (c)(3) above.

[Note: These initial compliance demonstration requirements are consistent with guidance from EPA Region 4. The span value is changed pursuant to Department authority and is consistent with guidance from EPA Region 4.]

(d) The owner or operator shall determine compliance with the sulfur content standard in 40 CFR 60.333(b) as follows: ASTM D 2880-71 shall be used to determine the sulfur content of liquid fuels and ASTM D 1072-80, D 3031-81, D 4084-82, or D 3246-81 shall be used for the sulfur content of gaseous fuels (incorporated by reference – see 40 CFR 60.17). The applicable ranges of some ASTM methods mentioned above are not adequate to measure the levels of sulfur in some fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the approval of the Administrator.

Department requirement: The permit specifies sulfur testing methods and allows the owner or operator to follow the requirements of 40 CFR 75 Appendix D to determine the sulfur content of liquid fuels.

[Note: This requirement establishes different methods than provided by paragraph (d) above, but the requirements are equally stringent and will ensure compliance with this rule.]

(e) To meet the requirements of 40 CFR 60.334(b), the owner or operator shall use the methods specified in paragraphs (a) and (d) of this section to determine the nitrogen and sulfur contents of the fuel being burned. The analysis may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency.

[Note: The fuel analysis requirements of the permit meet or exceed the requirements of this rule and will ensure compliance with this rule.]

SECTION V. APPENDIX XS

SEMI-ANNUAL CONTINUOUS EMISSIONS MONITOR SYSTEMS REPORT

{Note: This form is referenced in 40 CFR 60.7, Subpart A, General Provisions.}

Pollutant *(Circle One)*: Nitrogen Oxides (NOx) Carbon Monoxide (CO)

Reporting period dates: From ____________________ to ____________________

Company: ____________________

Emission Limitation: ____________________

Address: ____________________

Monitor Manufacturer and Model No.: ____________________

Date of Latest CMS Certification or Audit: ____________________

Process Unit(s) Description: ____________________

Total source operating time in reporting period [a]: ____________________

Emission data summary [a]		CMS performance summary [a]	
1. Duration of Excess Emissions In Reporting Period Due To:		1. CMS downtime in reporting period due to:	
a. Startup/Shutdown		a. Monitor Equipment Malfunctions	
b. Control Equipment Problems		b. Non-Monitor Equipment Malfunctions	
c. Process Problems		c. Quality Assurance Calibration	
d. Other Known Causes		d. Other Known Causes	
e. Unknown Causes		e. Unknown Causes	
2. Total Duration of Excess Emissions		2. Total CMS Downtime	
3. [Total Duration of Excess Emissions] x (100%) / [Total Source Operating Time] [b]		3. [Total CMS Downtime] x (100%) / [Total source operating time]	

[a] For opacity, record all times in minutes. For gases, record all times in hours.

[b] For the reporting period: If the total duration of excess emissions is 1 percent or greater of the total operating time or the total CMS downtime is 5 percent or greater of the total operating time, both the summary report form and the excess emission report described in 40 CFR 60.7(c) shall be submitted.

Note: *On a separate page, describe any changes to CMS, process or controls during last 6 months.*

I certify that the information contained in this report is true, accurate, and complete.

____
Name

____
Title

____________________ ____________________
Signature *Date*

G.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.

G.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 or exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.

G.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.

G.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.

G.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.

G.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.

G.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.

G.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.

G.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.

G.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.

G.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.

G.12 This permit or a copy thereof shall be kept at the work site of the permitted activity.

G.13 This permit also constitutes:

a) Determination of Best Available Control Technology (X)
b) Determination of Prevention of Significant Deterioration (X); and
c) Compliance with New Source Performance Standards (X).

G.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.

G.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.

APPENDIX BD
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

STANTON UNIT A COMBINED CYCLE PROJECT
OUC/KUA/FMPA/Southern Co.
PSD-FL-313 and PA81-14SA2
Orange County, Florida

BACKGROUND

The applicants, Orlando Utilities Commission (OUC), the Kissimmee Utility Authority (KUA), the Florida Municipal Power Agency (FMPA) and the Southern Company – Florida, LLC (SO), propose to build a 700 MW (estimated maximum gross capability) combined cycle power plant at the existing Curtis H. Stanton Energy Center. The location of the facility is 5100 South Alafaya Trail, Orlando, Orange County. The proposed project will result in "significant increases" with respect to Table 62-212.400-2, Florida Administrative Code (F.A.C.) of emissions of particulate matter (PM and PM_{10}), sulfur dioxide (SO_2), sulfuric acid mist (SAM), carbon monoxide (CO), volatile organic compounds (VOC), and nitrogen oxides (NO_X). Therefore, the project is subject to review for the Prevention of Significant Deterioration (PSD) and a determination of Best Available Control Technology (BACT) in accordance with Rules 62-212.400, F.A.C.

The primary units to be installed are two nominal 170 MW, General Electric "F" Class (PG7241FA) combustion turbine-electrical generators, fired with pipeline natural gas or diesel and equipped with evaporative coolers on the inlet air system. The project includes two heat recovery steam generators (HRSGs), each with a 160 ft. stack and one steam turbine-electrical generator rated at approximately 300 MW. Duct burners will be installed in the HRSGs for supplemental firing and to achieve peak output. The project also includes one 10-cell linear mechanical draft cooling tower, and one diesel fuel storage tank (approximately 1,680,000 gallons). Descriptions of the process, project, air quality effects, and rule applicability are given in the Technical Evaluation and Preliminary Determination dated June 30, 2001, accompanying the Department's Intent to Issue.

BACT APPLICATION:

The application was received on January 22, 2001 and included a proposed BACT proposal prepared by the applicant's consultant, Black & Veatch. The proposal is summarized in the table below for each combustion turbine (MW loads are assumed to be at 50% or higher).

POLLUTANT	CONTROL TECHNOLOGY	BACT PROPOSAL
PM/PM_{10}, VE	Clean Fuels Good Combustion	10 Percent Opacity 5 ppmvd Ammonia Slip
SO_2 / SAM	Clean Fuels	0.5 grains / 100 scf (gas) 0.05% Sulfur distillate oil – 1000 hours / year
CO	Pipeline Natural Gas Good Combustion	17 ppmvd (all operating modes) gas – 24 hr. avg. 14 ppmvd (all operating modes) oil – 24 hr. avg
VOC	Pipeline Natural Gas Good Combustion	3.6 ppmvd / 2.7 ppmvd (gas / oil) 6.3 ppmvd during DB plus PA
NO_X	DLN & SCR	3.5 ppmvd @ 15% O_2 (gas) 10 ppmvd @ 15% O_2 (oil)
PM - cooling tower	High efficiency drift eliminators	0.002% drift loss

Based upon the applicant's submittal, the maximum annual emissions that the facility has the poter emit (PTE) are as follows: 134.1 TPY SO_2, 17.6 TPY SAM, 127.6 TPY PM/PM_{10}, 314.5 TPY NO TPY CO and 105.8 TPY of VOC.

APPENDIX BD

BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

BACT DETERMINATION PROCEDURE:

In accordance with Chapter 62-212, F.A.C., this BACT determination is based on the maximum degree of reduction of each pollutant emitted which the Department of Environmental Protection (Department), on a case by case basis, taking into account energy, environmental and economic impacts, and other costs, determines is achievable through application of production processes and available methods, systems, and techniques. In addition, the regulations state that, in making the BACT determination, the Department shall give consideration to:

- Any Environmental Protection Agency determination of BACT pursuant to Section 169, and any emission limitation contained in 40 CFR Part 60 - Standards of Performance for New Stationary Sources or 40 CFR Part 61 - National Emission Standards for Hazardous Air Pollutants.
- All scientific, engineering, and technical material and other information available to the Department.
- The emission limiting standards or BACT determination of any other state.
- The social and economic impact of the application of such technology.

The EPA currently stresses that BACT should be determined using the "top-down" approach. The first step in this approach is to determine, for the emission unit in question, the most stringent control available for a similar or identical emission unit or emission unit category. If it is shown that this level of control is technically or economically unfeasible for the emission unit in question, then the next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical, environmental, or economic objections.

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES:

The minimum basis for a BACT determination is 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines (NSPS). Subpart GG was adopted by the Department by reference in Rule 62-204.800, F.A.C. The key emission limits required by Subpart GG are 75 ppmvd NO_X @ 15% O_2. (assuming 25 percent efficiency) and 150 ppmvd SO_2 @ 15% O_2 (or <0.8% sulfur in fuel). The BACT proposed by the applicant is consistent with the NSPS, which allows NO_X emissions in the range of 110 ppmvd for the high efficiency units to be purchased. No National Emission Standard for Hazardous Air Pollutants exists for stationary gas turbines.

The duct burners required for supplementary gas-firing of the HRSGs are subject to 40 CFR 60, Subpart Da, Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978. The 0.1 lb/MW-hr NO_X emission rate proposed by the applicant is well below the revised Subpart Da output-based limit of 1.6 lb/MW-hr promulgated on September 3, 1998. No National Emission Standards for Hazardous Air Pollutants exist for stationary gas turbines or gas-fired duct burners.

The distillate fuel oil storage tank is subject to 40 CFR 60, Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels (including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction or Modification Commenced After July 23, 1984.

DETERMINATIONS BY EPA AND STATES:

The following table is a sample of information on some recent BACT determinations by states for combined cycle stationary gas turbine projects. These are projects incorporating large prime movers capable of producing more than 150 MW excluding the steam cycle. Such units are typically categorized as F or G Class Frame units. The applicant's proposed BACT is included for reference.

APPENDIX BD

BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

TABLE 1

RECENT BACT LIMITS FOR NITROGEN OXIDES FOR LARGE STATIONARY GAS TURBINE COMBINED CYCLE PROJECTS

Project Location	Power Output Megawatts	NO_X Limit ppmvd @ 15% O_2 and Fuel	Technology	Comments
Mobile Energy, AL	~250	~3.5 - NG (CT&DB) ~11 – FO (CT&DB)	DLN & SCR	178 MW GE 7FA CT 1/99 585 mmBtu Duct Burner
KUA Cane Island 3	250	3.5 - (CT&DB)	DLN/SCR	170 MW GE 7FA. 11/99 Ammonia slip = 5 ppmvd
Calpine BHEC	1080	3.5 – (CT& DB)	DLN/SCR	Ammonia slip = 5 ppm
Calpine Delta	880	2.5 – (CT & DB) 1 hour average (LAER)	DLN/CSR	3 GE 7FA's or 3 WH 501FD's; 10 ppm max ammonia slip
Calpine Bullhead City	545	3.0 – (CT&DB)	DLN/SCR	Nearly identical to Osprey; Replace SCR catalyst after 36 mo.
Calpine Osprey	545	3.5 – (CT& DB)	DLN/SCR	Ammonia slip ≈ 9 ppm
Stanton A (proposed)	700	3.5 - NG (CT &DB & PA) 10 – FO	DLN/SCR	Ammonia slip = 5 ppm

DB = Duct Burner
NG = Natural Gas
FO = Fuel Oil
DLN = Dry Low NO_X Combustion
SCR = Selective Catalytic Reduction
WI = Water or Steam Injection
CT = Comb. Turbine
DB = Duct Burner
PA = Pwr. Augmentation
PA = Power Augmentation
WH = Westinghouse
GE = General Electric

TABLE 2

RECENT BACT LIMITS FOR CARBON MONOXIDE, VOLATILE ORGANIC COMPOUNDS, PARTICULATE MATTER, AND VISIBILITY FOR LARGE STATIONARY GAS TURBINE COMBINED CYCLE PROJECTS

Project Location	CO - ppmvd (or lb/mmBtu)	VOC - ppm (or lb/mmBtu)	PM - lb/mmBtu (or gr/dscf or lb/hr)	Technology and Comments
Mobile Energy, AL	~18 – NG (CT&DB) ~26 – FO (CT&DB)	~5 – NG ~6 - FO	10% Opacity	Clean Fuels Good Combustion
KUA Cane Island	10 - NG (CT) 20 - NG (CT&DB) 30 - FO	1.4 - NG (CT) 4 - NG (CT&DB) 10 - FO	10% Opacity	Clean Fuels Good Combustion
Calpine BHEC	10 – NG (CT only) 17 – NG (off-normal)	1.2 – NG (CT) 6.6 – NG (DB & PA)	10% Opacity 26.0 lb/hr (CT & DB)	Clean Fuels Good Combustion
Calpine Delta	10 – NG (CT & DB) 10 – NG (DB & PA) 3 hr avg. – No Ox. Cat.	2 - NG	0.25 gr.S/100 scf Nat. Gas	Clean Fuels Good Combustion
Calpine Bullhead City	10 – NG (CT & DB) 33.9 – NG (DB & PA) 3 hour rolling average	1.5 - NG	18.3 lb/hr (CT) 22.8 lb/hr (DB & PA)	Clean Fuels Good Combustion
Calpine Osprey	10 – NG (CT only) 17 – NG (off-normal)	2.3 – NG (CT) 4.6 – NG (DB & PA)	10% Opacity 24.1 lb/hr (CT & DB)	Clean Fuels Good Combustion
Stanton A (proposed)	14 –FO (CT only) 17 – NG (all gas modes)	2.7 – FO 6.3 – NG (DB & PA)	10% Opacity 11.7 / 17 lb/hr (NG / FO)	Clean Fuels Good Combustion

OTHER INFORMATION AVAILABLE TO THE DEPARTMENT:

Besides the initial information submitted by the applicant, the summary above, and the references at the end of this document, key information reviewed by the Department includes:

- Master Overview for Alabama Power Plant Barry Project received in 1998
- Letters from EPA Region IV dated February 2, and November 8, 1999 regarding KUA Cane Island 3
- Presentations by Black & Veatch and General Electric at EPA Region IV on March 4, 1999
- Letter from Black & Veatch to EPA Region IV dated March 10, 1999
- Letter from Black & Veatch to the Department and EPA Region IV dated March 24, 1999
- Texas Natural Resource Conservation Commission Draft Tier I BACT for August, 1999
- Texas Natural Resource Conservation Commission Website – www.tnrcc.state.tx.us
- DOE website information on Advanced Turbine Systems Project
- Alternative Control Techniques Document - NO_X Emissions from Stationary Gas Turbines
- General Electric 39th Turbine State-of-the-Art Technology Seminar Proceedings
- GE Guarantee for Jacksonville Electric Authority Kennedy Plant Project
- GE Power Generation - Speedtronic™ Mark V Gas Turbine Control System
- GE Combined Cycle Startup Curves
- Coen website information and brochure on Duct Burners

REVIEW OF NITROGEN OXIDES CONTROL TECHNOLOGIES:

Some of the discussion in this section is based on a 1993 EPA document on Alternative Control Techniques for NO_X Emissions from Stationary Gas Turbines. Project-specific information is included where applicable.

Nitrogen Oxides Formation

Nitrogen oxides form in the gas turbine combustion process as a result of the dissociation of molecular nitrogen and oxygen to their atomic forms and subsequent recombination into seven different oxides of nitrogen. Thermal NO_X forms in the high temperature area of the gas turbine combustor. Thermal NO_X increases exponentially with increases in flame temperature and linearly with increases in residence time. Flame temperature is dependent upon the ratio of fuel burned in a flame to the amount of fuel that consumes all of the available oxygen.

By maintaining a low fuel ratio (lean combustion), the flame temperature will be lower, thus reducing the potential for NO_X formation. Prompt NO_X is formed in the proximity of the flame front as intermediate combustion products. The contribution of Prompt to overall NO_X is relatively small in near-stoichiometric combustors and increases for leaner fuel mixtures. This provides a practical limit for NO_X control by lean combustion.

Fuel NO_X is formed when fuels containing bound nitrogen are burned. This phenomenon is not important when combusting natural gas. Although low sulfur fuel oil has more fuel-bound nitrogen than natural gas, its use is minimized (1000 hours) for this project and control of NO_X emissions are proposed to be with SCR.

Uncontrolled emissions range from about 100 to over 600 parts per million by volume, dry, corrected to 15 percent oxygen (ppmvd @15% O_2). The Department estimates uncontrolled emissions at approximately 200 ppmvd @15% O_2 for the proposed turbines. The proposed NO_X controls will reduce these emissions significantly.

NO_X Control Techniques

Wet Injection

Water or steam is injected into the primary combustion zone to reduce the flame temperature, resulting in lower NO_X emissions. Water injected into this zone acts as a heat sink by absorbing heat necessary to vaporize the water and raise the temperature of the vaporized water to the temperature of the exhaust gas stream. Steam injection uses the same principle, excluding the heat required to vaporize the water. Therefore, much more steam is required (on a mass basis) than water to achieve the same level of NO_X control. However, there is a physical limit to the amount of water or steam that may be injected before flame instability or cold spots in the combustion zone would cause adverse operating conditions for the combustion turbine. Standard combustor designs with wet injection can generally achieve NO_X emissions of 42/65 ppmvd for gas/oil firing. Advanced combustor designs generate lower NO_X emissions to begin with and can tolerate greater amounts of water or steam injection before causing flame instability. Advanced combustor designs with wet injection can achieve NO_X emissions of 25/42 ppmvd for gas/oil firing. Wet injection results in 60% to 80% control efficiencies.

Combustion Controls

The U.S. Department of Energy has provided millions of dollars of funding to a number of combustion turbine manufacturers to develop inherently lower pollutant-emitting units. Efforts over the last ten years have focused on reducing the peak flame temperature for natural gas fired units by staging combustors and premixing fuel with air prior to combustion in the primary zone. Typically, this occurs in four distinct modes: primary, lean-lean, secondary, and premix. In the primary mode, fuel is supplied only to the primary nozzles to ignite, accelerate, and operate the unit over a range of low- to mid-loads and up to a set combustion reference temperature. Once the first combustion reference temperature is reached, operation in the lean-lean mode begins when fuel is also introduced to the secondary nozzles to achieve the second combustion reference temperature. After the second combustion reference temperature is reached, operation in the secondary mode begins by shutting off fuel to the primary nozzle and extinguishing the flame in the primary zone. Finally, in the premix mode, fuel is reintroduced to the primary zone for premixing fuel and air. Although fuel is supplied to both the primary and secondary nozzles in the premix mode, there is only flame in the secondary stage. The premix mode of operation occurs between 50% to 100% of base load and provides the lowest NO_X emissions. Due to the intricate air and fuel staging necessary for dry low-NO_X combustor technology, the gas turbine control system becomes a very important component of the overall system. DLN systems result in control efficiencies of 80% to 95%.

Figure A (below) is an example of an in-line duct burner arrangement. Since duct burners operate at lower temperature and pressure than the combustion turbine, the potential for emissions is generally lower. Although the duct burners maximum heat input is 533 MMBtu/hr, it is relatively low when compared with the turbine that can accommodate a heat input greater than 2000 MMBtu/hr. The duct burners will be of a Low NO_X design and will be used to compensate for loss of capacity at high ambient temperatures.

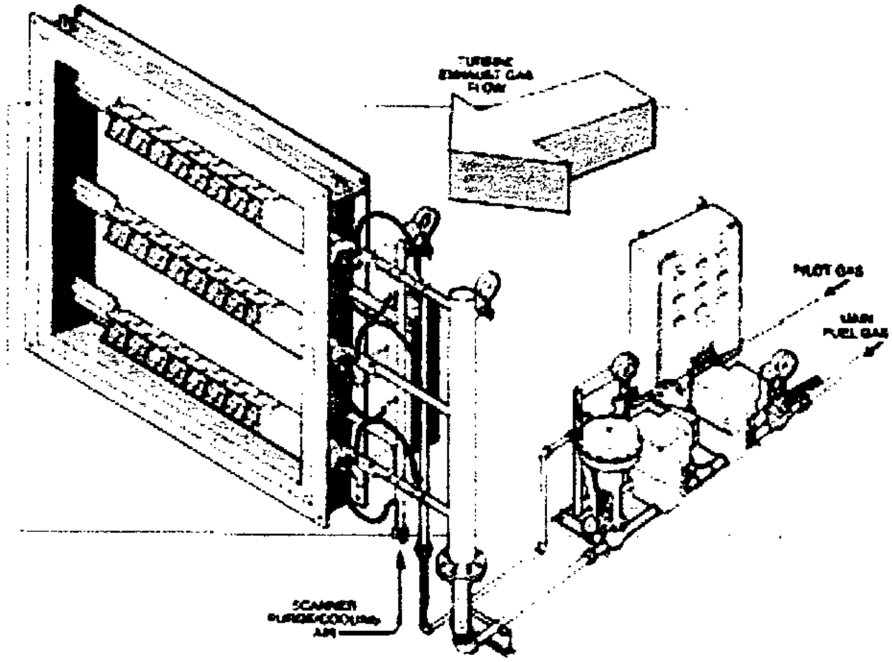


FIGURE A

Selective Catalytic Reduction

Selective catalytic reduction (SCR) is an add-on NO_X control technology that is employed in the exhaust stream within the HRSG. SCR reduces NO_X emissions by injecting ammonia into the flue gas in the presence of a catalyst. Ammonia reacts with NO_X in the presence of a catalyst and excess oxygen yielding molecular nitrogen and water. The catalysts used in combined cycle, low temperature applications (conventional SCR), are usually vanadium or titanium oxide and account for almost all installations. For high temperature applications (Hot SCR up to 1100 °F), such as simple cycle turbines, zeolite catalysts are available but used in few applications to-date. SCR units are typically used in combination with wet injection or DLN combustion controls.

In the past, sulfur was found to poison the catalyst material. Sulfur-resistant catalyst materials are now becoming commonplace and have recently been specified for CPV Gulf Coast (PSD-FL-300). In that review, the Department determined that SCR was cost effective for reducing NO_X emissions from 9 ppmvd to 3.5 ppmvd on a General Electric 7FA unit burning natural gas in combined cycle mode. This review additionally concluded that the unit would be capable of combusting 0.05%S diesel fuel oil for up to 30 days per year while emitting 10 ppmvd of NO_X. Catalyst formulation improvements have proven effective in resisting sulfur-induced performance degradation with fuel oil in Europe and Japan. These newer catalysts (versus the older alumina-based catalysts) are resistant to sulfur fouling at temperatures below 770°F (EPRI). In fact, Mitsubishi reports that as of 1998, SCR's were installed on 61 boilers which combust residual oil (40 of which are utility boilers) and another 70 industrial boilers, which fire diesel oil. Likewise, B & W reports satisfactory results with the installation of SCR to several large Taiwan Power Company utility boilers, which fire a wide range of coals, as well as heavy fuel oil with sulfur contents up to 2.0% and 50 ppm vanadium. Catalyst life in excess of 4 to 6 years has been achieved, while 8 to 10 years catalyst life has been reported with natural gas.

As of early 1992, over 100 gas turbine installations already used SCR in the United States. Only one combustion turbine project in Florida (FPC Hines Power Block 1) currently employs SCR. The equipment was installed on a temporary basis because Westinghouse had not yet demonstrated emissions as low as 12 ppmvd by DLN technology at the time the units were to start up in 1998. Seminole Electric will install SCR on a previously permitted 501F unit at the Hardee Unit 3 project and Kissimmee Utility Authority will install SCR on newly permitted Cane Island Unit 3. New combined cycle combustion turbine projects in Florida are normally considered to be prime candidates for SCR.

Figure B is a photograph of FPC Hines Energy Complex. The magnitude of the installation can be appreciated from the relative size compared with nearby individuals and vehicles. Figure C below is a diagram of a HRSG including an SCR reactor with honeycomb catalyst and the ammonia injection grid. The SCR system lies between low and high-pressure steam systems where the temperature requirements for conventional SCR can be met.

Figure B

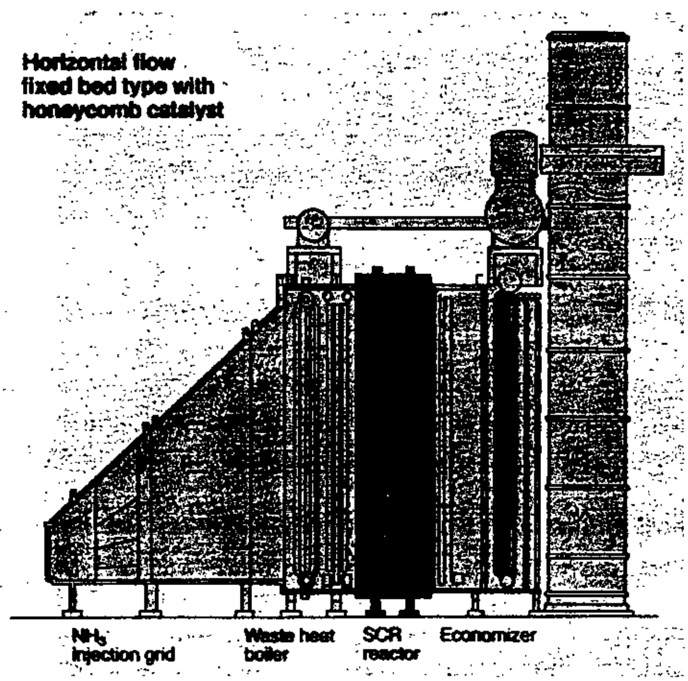


Figure C

Excessive ammonia use tends to increase emissions of CO, ammonia (slip), and particulate matter (when sulfur-bearing fuels are used). Permit limits as low as 2 to 3.5 ppmvd NO_X have been specified using SCR on combined cycle F Class projects throughout the country. Permit BACT limits of 3.5 ppmvd NO_X are being routinely specified using SCR for F Class projects (with large in-line duct burners) in the Southeast and even lower limits in the southwest.

Selective Non-Catalytic Reduction

Selective non-catalytic reduction (SNCR) reduction works on the same principle as SCR. The differences are that it is applicable to hotter streams than conventional or hot SCR, no catalyst is required, and urea can be used as a source of ammonia. Certain manufacturers, such as Engelhard, market an SCNR for NO_X control within the temperature ranges for which this project will operate (700 – 1400°F). However, the process also requires a low oxygen content in the exhaust stream in order to be effective. Given that a top-down review leads one to an SCR in this application, SNCR does not merit further consideration.

Emerging Technologies: SCONOx™ and XONON™

SCONOx™ is a catalytic technology that achieves NO_X control by oxidizing and then absorbing the pollutant onto a honeycomb structure coated with potassium carbonate. The pollutant is then released as harmless molecular nitrogen during a regeneration cycle that requires dilute hydrogen gas. The technology has been demonstrated on small units in California and has been purchased for a small source in Massachusetts.[1] California regulators and industry sources have permitted the La Paloma Plant near Bakersfield for the installation of one 250 MW block with SCONOx ™[2]. The overall project includes several more 250 MW blocks with SCR for control.[3] According to industry sources, the installation has proceeded with a standard SCR due to schedule constraints. Recently, PG&E Generating has been approved to install SCONOx™ on two F frame units at Otay Mesa, approximately 15 miles S.E. of San Diego, California. Additionally, USEPA has identified an "achieved in practice" BACT value of 2.0 ppmvd over a three-hour rolling average based upon the recent performance of a Vernon, California natural gas-fired 32 MW combined cycle turbine (without duct burners) equipped with the patented SCONOx™ system.

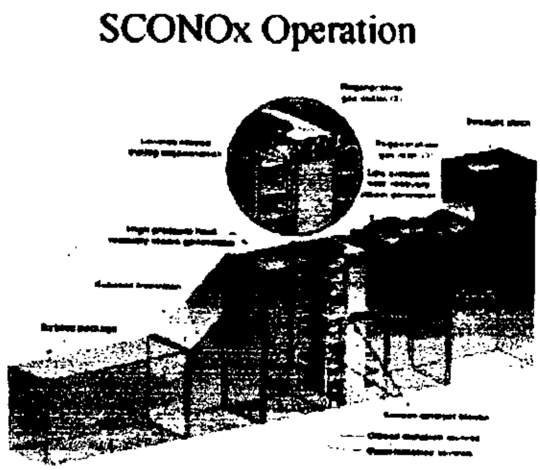


Figure D

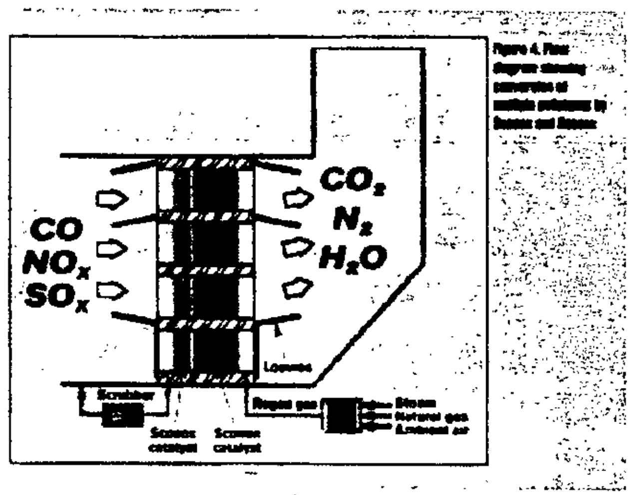


Figure E

SCONOx™ technology (at 2.0 ppmvd) is considered to represent LAER in non-attainment areas where cost is not a factor in setting an emission limit. It competes with less-expensive SCR in those areas, but has the advantages that it does not cause ammonia emissions in exchange for NO_X reduction. Advantages of the SCONOx ™ process include (in addition to the reduction of NO_X) the elimination of ammonia and the control of VOC and CO emissions. SCONOx™ has not been applied on any major sources in ozone attainment areas, apparently only due to cost considerations. The Department is interested in seeing this technology implemented in Florida and intends to continue to work with applicants seeking an opportunity to demonstrate ammonia-free emissions on a large unit. The Department estimates that the application of this control technology to the Stanton A Combined Cycle Unit results in cost-effectiveness of just less than $10,000 per ton of NO_X removed. Although there are specific items within the applicant's original analysis (which estimates a cost effectiveness of $10,200 per ton of NO_X and CO removed from each CT/HRSG) that the Department cannot support (e.g. lost power revenues, contingency factors above 3%, etc.) on balance the Department concurs with the conclusion that $SCONO_X$ is not likely cost-effective for this project.

Catalytica Energy Systems, Inc. develops, manufactures and markets the XONON™ Combustion System. XONON™, which works by partially burning fuel in a low temperature pre-combustor and completing the combustion in a catalytic combustor. The overall result is low temperature partial combustion (and thus lower NO_X combustion) followed by flameless catalytic combustion to further attenuate NO_X formation. The technology has been demonstrated on combustors on the same order of size as SCONOx™ has. XONON™ avoids the emissions of ammonia and the need to generate hydrogen. It is also extremely attractive from a mechanical point of view.

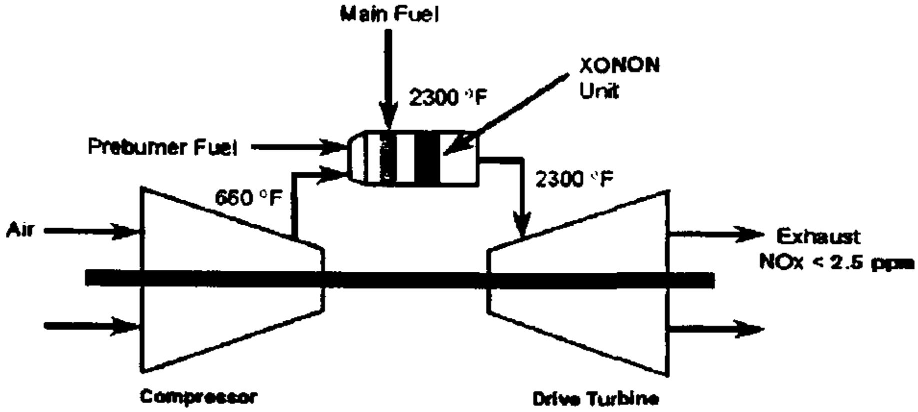
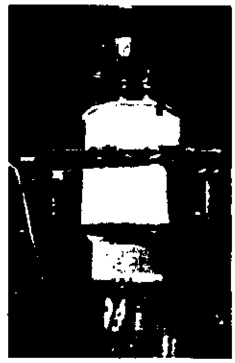


Figure F



XONON-2 installed with test instruments

Figure G

On February 8, 2001, Catalytica Energy Systems, Inc. announced that its XONON™ Cool Combustion system had successfully completed an evaluation process by the U.S. Environmental Protection Agency (EPA), which verified the ultra-low emissions performance of a XONON™-equipped gas turbine operating at Silicon Valley Power. The performance results gathered through the EPA's Environmental Technology Verification (ETV) Program provide high-quality, third party confirmation of XONON™ 's ability to deliver a near-zero emissions solution for gas turbine power production. The verification, which was conducted over a two-day period on a XONON™-equipped Kawasaki M1A-13A (1.4 MW) gas turbine operating at Silicon Valley Power, recorded nitrogen oxides (NO_X) emissions of less than 2.5 parts per million (ppm) and ultra-low emissions of carbon monoxide and unburned hydrocarbons.

The XONON™-equipped Kawasaki M1A-13A gas turbine has operated for over 7400 hours at Silicon Valley Power (SVP), a municipally owned utility, supplying near pollution-free power to the residents of the City of Santa Clara, California, with NO_X levels averaging under 2.5 ppm. Three XONON™-equipped Kawasaki M1A-13X turbines, a slightly modified commercial version of the M1A-13A, are expected to enter commercial service in late 2001 in Massachusetts at a healthcare facility of a U.S. Government agency.

In a definitive agreement signed on November 19, 1998, GE Power Systems and Catalytica agreed to the commercialization of the XONON™ system for new and existing GE gas turbines. The agreement provides for the collaborative adaptation of XONON™ combustion technology to GE gas turbines for commercial sale. In December 1999, GE accepted the first order for XONON™ -equipped GE 7FA gas turbines as the preferred emission control system for Enron's proposed Pastoria Energy Facility. This appears to be an up-and-coming technology, the development of which will be watched closely by the Department for future applications. However, the technology cannot (at this time) be recommended for the attendant project.

APPENDIX BD

BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

REVIEW OF PARTICULATE MATTER (PM/PM_{10}) AND SO_2 CONTROL TECHNOLOGIES:

Particulate matter is generated by various physical and chemical processes during combustion and will be affected by the design and operation of the NO_X controls. The particulate matter emitted from this unit will mainly be less than 10 microns in diameter (PM_{10}).

Natural gas is an inherently clean fuel and contains no ash. Natural gas and very low sulfur fuel oil (0.05%) will be the only fuels fired at the Stanton Combined Cycle Unit and they are efficiently combusted in gas turbines making any conceivable add-on control technique for PM/PM_{10} or SO_2 either unnecessary or impractical.

A technology review indicated that the top control option for PM/PM_{10} as well as SO_2 is a combination of good combustion practices, fuel quality, and filtration of inlet air.

The applicant has identified PM emissions over 20 TPY from the fresh-water cooling towers. Accordingly, drift eliminators shall be installed to reduce PM/PM_{10}. The drift eliminators shall be designed and maintained to reduce drift to 0.002 percent of the circulating water flow rate. No PM testing is required because the Department's Emission Monitoring Section has determined that there is no appropriate PM test method for these types of cooling towers.

REVIEW OF CARBON MONOXIDE (CO) CONTROL TECHNOLOGIES

CO is emitted from combustion turbines due to incomplete fuel combustion. Combustion design and catalytic oxidation are the control alternatives that are viable for the project. The most stringent control technology for CO emissions is the use of an oxidation catalyst (excluding the SCONOx ™ process).

Among the most recently permitted projects with oxidation catalyst requirements are the 500 MW Wyandotte Energy project in Michigan, the El Dorado project in Nevada, Ironwood in Pennsylvania, Millenium in Massachusetts, and Calpine Sutter in California. The permitted CO values of these units are between 3 and 5 ppmvd. Catalytic oxidation was recently installed at a cogeneration plant at Reedy Creek (Walt Disney World), Florida to avoid PSD review, which would have been required due to increased operation at low load. Seminole Electric will install oxidation catalyst to meet the permitted CO limit at its planned 244 MW Westinghouse 501FD combined cycle unit in Hardee County, Florida.[4]

Most combustion turbines incorporate good combustion to minimize emissions of CO. These installations typically achieve emissions between 10 and 30 ppmvd at full load, even as they achieve relatively low NO_X emissions by SCR or dry low NO_X means. OUC/KUA/FMPA/SO propose to meet a limit of 14 ppmvd while firing fuel oil above 50% output. However, the applicant prefers to be permitted with higher values of 18.1 ppmvd and 27.9 ppmvd for the full output operating modes of duct burner firing, and duct burner firing with power augmentation, respectively. Duct burner firing is requested for the entire year and power augmentation is requested for up to 1000 hours per year.

The Department has reviewed actual data from similar facilities and has reasonable assurance that the General Electric PG7241FA units selected by the applicant will achieve values well below those proposed by the applicant (and guaranteed by GE), without requiring installation of an oxidation catalyst. However, should the applicant desire to obtain a sufficient operating margin above the BACT established limit identified below, the permit will authorize the installation of oxidation catalysts at an established limit of 5 ppmvd CO, providing that the applicant installs the catalyst within 24 months of commercial operation. Otherwise, the Department will require the use of a CEMS for compliance on a 24-hour block average, with two limits depending upon actual operation. The limits will be:

a) 14 ppmvd based upon a 24-hour block average for all periods of fuel oil firing; otherwise, the limit is

b) 17 ppmvd for all operating modes, based upon a 24-hour block average, which is consistent with the recently issued determination made at Blue Heron Energy Center

REVIEW OF VOLATILE ORGANIC COMPOUND (VOC) CONTROL TECHNOLOGIES

Volatile organic compound (VOC) emissions, like CO emissions, are formed due to incomplete combustion of fuel. The high flame temperature is very efficient at destroying VOC. The applicant has proposed good combustion practices to control VOC. The limits proposed by the applicant for this project are 3.6 ppmvd for gas firing with duct burners, 2.7 ppmvd while firing oil and 6.3 ppmvd during operation with duct burners plus power augmentation. According to the applicant's submittals, VOC emissions less than 2 ppm will be achieved at 100% output and duct burners off. [5]

REVIEW OF HAZARDOUS AIR POLLUTANTS (HAPS) CONTROL TECHNOLOGIES

Based upon the application, this facility will not emit HAPS above the significance thresholds, which would require the application of MACT. However, some question exists concerning the accuracy of the proposed emission factors, particularly that of formaldehyde. The emission factors that have been proposed by the applicant are 8.42E-5 lb/MMBtu and 1.90E-4 lb/MMBtu for gas and oil respectively. According to EPA (Sims Roy memo dated 12-30-1999) the average formaldehyde factors for combustion turbines across all loads are 3.10E-3 lb/MMBtu and 2.81E-4 lb/MMBtu for gas and oil respectively. Although the discrepancy between the oil factors is fairly small, the applicant's gas factor is less than 3% of EPA's gas factor. FDEP must point out that the applicant's gas factor *is* within the range of factors reported by EPA (which is as low as 2.21E-6 lb/MMBtu) but the application of the EPA factor *would* subject the units to MACT. Additional EPA documentation on emission factors (from the same source as that proposed by the applicant, AP-42) suggests that the factor to be used is 7.10E-4 lb/MMBtu, which is approximately 8 times higher than that proposed by the applicant, and would also trigger a MACT review. Accordingly, the applicant's proposed emission factor may indeed be accurate for the proposed machine and configuration, and cannot be rejected outright, but must be known with a higher degree of accuracy. In order to resolve this question, each CT/HRSG will be required to undergo special testing for formaldehydes along with the other initial set of tests normally required. These tests will be structured so as to represent the PTE for formaldehydes at each of the maximum permitted operating modes. Should the results of this testing show that the emissions unit(s) will exceed 10 TPY of formaldehydes based upon maximum permitted conditions, the installation of an oxidation catalyst shall be required.

DEPARTMENT MACT DETERMINATION

Following are the MACT limits and testing protocol for formaldehyde at the Stanton A Combined Cycle project. Each CT/DB shall conduct tests and report emissions as per below and described within the permit:

OPERATING MODE	TEST PROTOCOL	TPY CALCULATION
Maximum CT output Natural Gas: Duct Burner firing at maximum output	CARB Method 430 or EPA Method 0011	(6760/2000) times measured Lb/Hour Formaldehyde
Maximum CT output Natural Gas: Duct Burner firing and Power Augmentation implemented, both at maximum output	CARB Method 430 or EPA Method 0011	(1000/2000) times measured Lb/Hour Formaldehyde
Maximum output, Fuel Oil	CARB Method 430 or EPA Method 0011	(1000/2000) times measured Lb/Hour Formaldehyde

Note: Results of the sampling method(s) shall be blank corrected.

DEPARTMENT BACT DETERMINATION

Following are the BACT limits determined for the Stanton A Combined Cycle project assuming full load. Values for NO_X and CO are corrected to 15% O_2. The emission limits (or their equivalents) as well as the applicable averaging times are itemized within the Specific Conditions of the permit.

POLLUTANT	CONTROL TECHNOLOGY	BACT
PM/PM_{10}, VE	Clean Fuels Good Combustion	10 Percent Opacity 5 ppmvd Ammonia Slip
SO_2 / SAM	Clean Fuels	0.5 grains / 100 scf (gas) 0.05% Sulfur distillate oil for 1000 hrs / year
CO	Pipeline Natural Gas Good Combustion	17 ppmvd (all operating modes) gas – 24 hr. avg. 14 ppmvd (all operating modes) oil – 24 hr. avg. 5 ppmvd (CT & DB & PA) with ox. catalyst
VOC	Pipeline Natural Gas Good Combustion	3.6 ppmvd / 2.7 ppmvd (gas / oil) 6.3 ppmvd during DB plus PA 3 ppmvd (CT & DB & PA) with ox. catalyst
NO_X	DLN & SCR	3.5 ppmvd @ 15% O_2 (gas) 10 ppmvd @ 15% O_2 (oil)
PM - cooling tower	High efficiency drift eliminators	0.002% drift loss
Formaldehyde	Oxidation Catalyst	MACT requirement if > 10 TPY

RATIONALE FOR DEPARTMENT'S DETERMINATION

- The Lowest Achievable Emission Rate (LAER) for NO_X is approximately 2 ppmvd. It has been achieved at a small combustion turbine installation using $SCONO_X$.
- EPA Region IV advised that the Department (in a draft BACT) did not present "any unusual site-specific conditions associated with the KUA Cane Island 3 project to indicate that the use of SCR to achieve 3.5 ppmvd would create greater problems than experienced elsewhere at other similar facilities."[6] The Fish & Wildlife Service had similar comments for Calpine Osprey Energy Center.[8]
- FDEP considers a 3-hour averaging time for NO_X compliance and a 5-ppmvd ammonia slip rate to be BACT, as can be seen in other recent BACT Determinations.
- Uncertainties (and statistical variances) in NO_X emissions related to instrumentation, methodology, calibration and sampling errors, exhaust flow, ammonia slip bias, corrections to 15% O_2 and ambient conditions, etc., are approximately equal to "ultra low NO_X" limits (2.5-3.5 ppmvd).[7]
- VOC emissions of < 2 ppm from the combustion turbine by Good Combustion proposed by the applicant are acceptable values determined as BACT. However, values less than 1 ppm have already been achieved on the DLN 2.6 combustors (GE 7FA) units after tuning.
- The CO emission rate will be verified continuously with CEMS. With the duct burner on, emissions will be less than 19 ppmvd, which is within the range of recent Department BACT determinations for combustion turbines alone. However, values as high as 28 ppmvd will not be authorized, as requested by the applicant. The CO limit will be 17 ppmvd on a weighted daily (24-hour block) average, which incorporates a reasonable allowance for all daily off-normal operations. In order to accommodate the applicant's concerns over the stringency of the limit, the installation of an oxidation catalyst will be authorized, provided that it is installed in a timely fashion.

- For reference, the CO limit for the FPL Fort Myers project is 12 ppmvd. Limits for the Santa Rosa Energy Center are 9 ppmvd with the duct burner off and 24 ppmvd with the duct burner on. The CO impact on ambient air quality is lower compared to other pollutants because the allowable concentrations of CO are much greater than for NO_X, SO_2, VOC (ozone) or PM_{10}.
- PM_{10} emissions will be very low and difficult to measure. Therefore, the Department will set a Visible Emission standard of 10 percent opacity as BACT.

COMPLIANCE PROCEDURES

POLLUTANT	COMPLIANCE PROCEDURE
PM/Visible Emissions	Method 5 (initial test only) and Method 9 (annually)
Volatile Organic Compounds	Method 18, 25, or 25A (initial tests only)
Carbon Monoxide	CEMS plus annual method 10 during operation at capacity without use of duct burners and power augmentation
VOC and CO with Oxidation Catalyst	Annual Method 18, 25 or 25A and Method 10 with Duct Burners and Power Augmentation
NO_X 3-hr block average	NO_X CEMS. O_2 or CO_2 diluent monitor, and flow device as needed
NO_X (performance)	Annual Method 20 or 7E
Formaldehyde	CARB Method 430 or EPA Method 0011

BACT EXCESS EMISSIONS APPROVAL

Pursuant to the Rule 62-210.700 F.A.C., the Department through this BACT determination will allow excess emissions as follows: Valid hourly emission rates shall not included periods of startup, shutdown, or malfunction as defined in Rule 62-210.200 F.A.C., where emissions exceed the applicable standard. These excess emissions periods shall be reported as required within the Specific Conditions of the Permit. A valid hourly emission rate shall be calculated for each hour in which at least two pollutant concentrations are obtained at least 15 minutes apart. The following emission levels represent excess emission *estimates* during startup periods:

STARTUP TYPE	TIME	ESTIMATED EMISSION MAXIMUM LEVELS BY POLLUTANT FOR EACH CT (TOTAL lbm)				
		NO_X	SO_2	PM_{10}	VOC	CO
Natural Gas - Cold	4 hours	160	0	48	80	500
Natural Gas - Hot / Warm	2 hours	80	0	24	40	250

STARTUP TYPE	TIME	ESTIMATED EMISSION MAXIMUM LEVELS BY POLLUTANT FOR EACH CT (TOTAL lbm)				
		NO_X	SO_2	PM_{10}	VOC	CO
Distillate Oil - Cold	4 hours	360	400	70	80	500
Distillate Oil - Hot / Warm	2 hours	180	200	35	40	250

The following emissions (TPY) are shown for informational purposes only. They represent a *conservative* estimate of annualized startup emissions, which are largely controllable through best operating practices.

Since each startup requires many hours of preceding shutdown time where emissions are zero, there will likely be *no annual net emission increase* from the previously estimated TPY:

STARTUP TYPE	NO. REQUIRED	NO_X	SO_2	PM_{10}	VOC	CO
Cold	48 (2 on oil)	4.1	0.4	1.2	1.9	12.0
Hot / Warm	240 (10 on oil)	10.1	1.0	0.7	4.8	30.0
Total	288 (12 on oil)	14.2	1.4	1.9	6.7	42.0

Excess emissions may occur under the following startup scenarios, subject to Rule 62-210.700, F.A.C. However, excess emissions resulting from startup, shutdown, or malfunction shall *only* be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized. 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 pursuant to Rule 62-210.700, F.A.C. These emissions shall be included in the 3-hr average for NO_X and the 24-hr average for CO.

Hot / Warm Start: Two hours following a HRSG shutdown less than 72 hours.

Cold Start: Four hours following a HRSG shutdown greater than or equal to 72 hours.

DETAILS OF THE ANALYSIS MAY BE OBTAINED BY CONTACTING:

Michael P. Halpin, P.E. Review Engineer
Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Recommended By:

C. H. Fancy, P.E., Chief
Bureau of Air Regulation

Date:

Approved By:

Howard L. Rhodes, Director
Division of Air Resources Management

Date:

REFERENCES

[1] News Release. Goaline Environmental. Genetics Institute Buys SCONOx Clean Air System. August 20, 1999.

[2] "Control Maker Strives to Sway Utility Skeptics." Air Daily. Volume 5, No. 199. October 14, 1998.

[3] Telecom. Linero, A.A., FDEP, and Beckham, D., U.S. Generating. Circa November 1998.

[4] Letter. Opalinski, M.P., SECI to Linero, A.A., FDEP. Turbines and Related Equipment at Hardee Unit 3. December 9, 1998.

[5] Application for Air Permit, Attachment 2 Performance Data – GE Performance Data Natural Gas Firing Only.

[6] Letter. Neeley, R. Douglas, EPA Region IV, to Fancy, C.H., FDEP. Draft PSD Permit – KUA Project. February 2, 1999.

[7] Zachary, J, Joshi, S., and Kagolanu, R., Siemens. "Challenges Facing the Measurement and Monitoring of Very Low Emissions in Large Scale Gas Turbine Projects." Power-Gen Conference. Orlando, Florida. December 9-11, 1998.

[8] Letter. Porter, Ellen to Linero, A.A., FDEP. Technical Review of Prevention of Significant Deterioration Permit Application For Osprey Energy Center. April 17, 2000.

Memorandum

Florida Department of Environmental Protection

TO: ~~Clair Fancy~~ by Cly

THRU: Al Linero Cly

FROM: Michael P. Halpin MPH

DATE: May 17, 2001

SUBJECT: OUC Curtis H. Stanton Energy Center
Combined Cycle Addition
DEP File No. 0950137-002-AC (PSD-FL-313)

Attached is the public notice package for the addition of a combined cycle unit to be installed at OUC's Stanton Plant in Orlando. This project has been submitted as a joint application from four owners: OUC, KUA, FMPA and Southern Company – Florida, LLC, although the authorized representative is from Gulf Power. This permit will allow the installation of two General Electric 7FA CT's with flue gas routed through supplementary fired HRSGs (one for each CT), the steam from which will be sent to one steam turbine rated at approximately 300 MW. The maximum megawatt output will be approximately 700MW under specified conditions.

Nitrogen Oxides (NO_X) emissions from the gas turbines will be controlled by Dry Low NO_X (DLN-2.6) plus SCR for gas firing, and water injection plus SCR for oil firing. Emission limits for NO_X will be set at 3.5 ppmvd for gas firing and 10 ppmvd for oil firing. CO emissions will be limited to 17 ppmvd on a 24-hour average by CEMS (while firing natural gas) regardless of mode of operation. The use of 0.05% sulfur fuel oil will be allowed for up to 1000 hours per year on each CT, during which CO emissions will be limited to 14 ppmvd on a 24-hour average by CEMS.

Emissions of sulfur dioxide, SAM, volatile organic compounds and particulate matter (PM/PM_{10}) will be very low because of the inherently clean pipeline quality natural gas, limited fuel oil use and the design of the GE unit.

Based upon input from the EPA, the Department will require the applicant to validate the formaldehyde emission factor (which was utilized in the application) upon initial commissioning of the units. The results of that testing may require that the applicant install oxidation catalysts, and this has been provided for within the BACT and permit.

According to Buck Oven, this project is on a faster track than most projects, which are subject to the Siting Act, since it is a modification to an existing certification. In fact, Buck indicates that (barring a request for an extension of time) he needs to have the PSD work by no later than Tuesday, May 22nd. Fortunately, we were able to support the time-line and are prepared to issue as per the attached documentation.

I recommend your approval of the attached Intent to Issue.

AAL/mph

Attachments

P.E. Certification Statement

OUC/KUA/FMPA/Southern Company – Florida, LLC
Curtis H. Stanton Energy Center
Orange County

DEP File No.: 0950137-002-AC (PSD-FL-313)
Facility ID No.: 0950137

Project: PSD Permit

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

Cleve Holladay and I conducted this review.

(Seal)

Michael P. Halpin

Michael P. Halpin, P.E.
Registration Number: 31970

May 16, 2001
Date

Permitting Authority:
Florida Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation
New Source Review Section
Mail Station #5505
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Telephone: 850/488-0114
Fax: 850/922-6979

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 4
ATLANTA FEDERAL CENTER
61 FORSYTH STREET
ATLANTA, GEORGIA 30303-8960

MAY 17 2001

RECEIVED

MAY 21 2001

BUREAU OF AIR REGULATION

4APT-ARB

Al Linero, P.E.
Florida Department of Environmental Protection
Mail Station 5500
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Dear Mr. Linero:

Thank you for sending a copy of the prevention of significant deterioration (PSD) permit application for a project at the Curtis H. Stanton Energy Center in Orange County, Florida. The proposed project will consist of two combined cycle combustion turbine units. The following equipment is associated with the project: two 317-MW General Electric (Model PG7241FA) combined cycle combustion turbines with heat recovery steam generator (HRSG), supplemental duct firing, a 10-cell cooling tower, and a No. 2 distillate fuel oil storage tank. Natural gas will be the primary fuel for each unit, with No. 2 fuel oil as a backup. Based on the applicant's emission estimates, the pollutants subject to PSD review are nitrogen oxides (NO_x), carbon monoxide (CO), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), and volatile organic compounds (VOC).

We have reviewed the permit application and have discussed our comments and concerns by telephone with Mr. Mike Halpin of the Florida Department of Environmental Protection (FDEP) on May 10, 2001. Our comments concerning the application are as follows:

1. We are especially interested in this project because it is subject to Florida Power Plant Siting Act requirements. The PSD permitting program for Power Plant Siting Act projects is a delegated program with FDEP acting on behalf of the U.S. Environmental Protection Agency (EPA).

2. The application states that the best available control technology (BACT) for sulfur dioxide emissions is combustion with inherently low sulfur content fuels - natural gas and fuel oil with less than 0.05 percent sulfur. Fuel oil with a sulfur content equal to 0.05 percent sulfur has been commonly cited as BACT for SO_2 emissions. Prior to issuing a draft permit, FDEP should confirm that the applicant can consistently meet a fuel oil sulfur content of less than 0.05 percent as proposed in the BACT assessment.

3. Based on the applicant's estimates, potential VOC emissions exceed 100 tons per year. The applicant should therefore provide a justification for an exemption from preconstruction ambient ozone monitoring. The applicant should also comment on whether VOC emissions of this magnitude are likely to result in an adverse ambient air quality impact with respect to ozone formation.

4. The application contains hazardous air pollutant (HAP) emission estimates for the combustion turbines. The formaldehyde emission factor stated in the application (8.42×10^{-6} lb/MMBtu) is said to be derived from AP-42. This factor, however, is approximately two orders of magnitude less than the direct AP-42 emission factor of 7.1×10^{-4} lb/MMBtu. The applicant should provide more information on the derivation of the formaldehyde emission factor for combustion turbines.

5. The permit application does not address how the applicant will minimize emissions during startups and shutdowns. EPA considers periods of startup and shutdown to be a part of normal source operation, and we encourage FDEP to regulate these emissions directly in the PSD permit. Startup and shutdown control options that could be considered include (but are not limited to) the following: limitations on the number of startups and shutdowns in any 12-month period; limitations on the number of hours allowed in any 24-hour period for excess NO_x and CO emissions due to startup and shutdown conditions; mass emission limits for NO_x and CO emissions during any 24-hour period to include emissions during startup and shutdown; and future establishment of startup and shutdown BACT emission limits for NO_x and CO derived from test results during the first few months of commercial operation. At a minimum, the permit should include a definition of the words startup and shutdown in terms of the observable operating conditions that indicate a period of startup and a period of shutdown.

6. The BACT cost analysis for catalytic oxidation contains the following questionable features: possible double counting of catalyst cost; property taxes equal to 2.75 percent of total capital investment rather than the 1 percent in the EPA *OAQPS Control Cost Manual*; and a cost for lost power generation that EPA generally considers inappropriate for electric power generation projects. Also, it is unclear how the $306,000 catalyst replacement cost was derived.

If you have any questions regarding these comments, please call Daphne Wilson at (404) 562-9118.

Sincerely,

Douglas Neeley

R. Douglas Neeley
Chief
Air and Radiation Technology Branch
Air, Pesticides and Toxics Management
Division

cc: M. Halpin
C. Holladay
R. Moore, Gulf Power
J. Vick, Gulf Power
R. Unruh, Black & Veatch
J. Bunyak, NPS
Z. Kozlov, CD
J. Buford
B. Oven, DEP

Memorandum

Florida Department of Environmental Protection

TO: Al Linero
Len Kozlov
Geof Mansfield
Mary Jean Yon

RECEIVED

FEB 06 2001

BUREAU OF AIR REGULATION

FROM: Buck Oven

DATE: February 6, 2001

SUBJECT: Orlando Utilities Commission - Stanton Energy Center, Combined Cycle Unit A, Supplemental Application, PA 81-14SA2, Module 8024

OUC in conjunction with Kissimmee Utilities Authority (KUA), Florida Municipal Power Agency (FMPA) and Southern Company submitted on January 22, 2001, a supplemental application for certification of a natural gas-fired, combined cycle facility at the Stanton Energy Center. We have determined that the application is "complete" according to Siting rules. Black & Veatch are starting to distribute the application. Please have your respective staffs review the application for sufficiency and submit their comments to me by March 9, 2001.

cc: Scott Goorland

FLORIDA

Department of Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

January 24, 2001

Mr. Gregg Worley, Chief
Air, Radiation Technology Branch
Preconstruction/HAP Section
U.S. EPA, Region 4
61 Forsyth Street
Atlanta, Georgia 30303

RE: Orlando Utilities Commission.
Curtis H. Stanton Energy Center
Facility ID No. 0950137-002-AC, PSD-FL-313

Dear Mr. Worley:

Enclosed for your review and comment is an application for Orlando Utilities Commission, in conjunction with Kissimmee Utility Authority, Florida Municipal Power Authority, and Southern-Florida to construct and operate a 633 MW electric generating unit at the existing Curtis H. Stanton Energy facility in Orange County, Florida

Your comments may be forwarded to my attention at the letterhead address or faxed to the Bureau of Air Regulation at 850/922-6979. If you have any questions, please contact Teresa Heron, review engineer, at 850/921-9529.

Sincerely,

Patty Adams

for Al Linero, P.E.
Administrator
New Source Review Section

AAL/pa

Enclosure

cc: Teresa Heron