Department of Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

December 16, 1994

CERTIFIED MAIL-RETURN RECEIPT REQUESTED

Mr. Michael L. Kurtz
General Manager for Utilities
Gainesville Regional Utilities
P. O. Box 147117 - Station A-134
Gainesville, Florida 32614-7117

Dear Mr. Kurtz:

Attached is one copy of the Technical Evaluation and Preliminary Determination, proposed BACT determination, and proposed permit to construct a 74 MW simply cycle combustion turbine at Gainesville Regional Utilities's existing facility located off US 441 North in Alachua County, Florida.

Please submit any written comments you wish to have considered concerning the Department's proposed action to Mr. John Brown of the Bureau of Air Regulation.

Sincerely,

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

CHF/TH/bjb

Attachments

cc: C. Kirts, NED
J. Harper, EPA
J. Bunyak, NPS
B. Oven, PPS, DEP
D. Graziani, P.E., FWI

Is your RETURN ADDRESS completed on the reverse side?

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3. Article Addressed to:
Mr. Michael L. Kurtz
General Manager for Utilities
Gainesville Regional Utilities
P. O. Box 147117 - Station A-134
Gainesville, FL 3261407117

4a. Article Number
P 872 562 688

4b. Service Type
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PS Form 3811, December 1991 ☆U.S. GPO: 1992—323-402 **DOMESTIC RETURN RECEIPT**

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PS Form 3800, JUNE 1991

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

CERTIFIED MAIL

In the Matter of an
Application for Permit by:

DEP File No. PSD-FL-212
Alachua County

City of Gainesville,
Gainesville Regional Utilities
P. O. Box 147117, Station A-134
Gainesville, Florida 32614-7117
_______________________________/

INTENT TO ISSUE

The Department of Environmental Protection (Department) gives notice of its intent to issue a permit (copy attached) for the proposed project as detailed in the application specified above, for the reasons stated in the attached Technical Evaluation and Preliminary Determination.

The applicant, the City of Gainesville, applied on March 22, 1994, to the Department for a permit to construct a 74 MW simple cycle combustion turbine at Gainesville Regional Utilities's existing facility. The facility is located off US 441 North in Alachua County, Florida.

The Department has permitting jurisdiction under the provisions of Chapter 403, Florida Statutes (F.S.), and Chapters 62-212 and 62-4, Florida Administrative Code (F.A.C.). The project is not exempt from permitting procedures. The Department has determined that a construction permit is required for the proposed work.

Pursuant to Section 403.815, F.S. and Rule 62-103.150, F.A.C., you (the applicant) are required to publish at your own expense the enclosed Notice of Intent to Issue Permit. The notice shall be published one time only within 30 days in the legal ad section of a newspaper of general circulation in the area affected. For the purpose of this rule, "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. The applicant shall provide proof of publication to the Department's Bureau of Air Regulation, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400, within 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.

The Department will issue the permit with the attached conditions unless a petition for an administrative proceeding (hearing) is filed pursuant to the provisions of Section 120.57, F.S.

A person whose substantial interests are affected by the Department's proposed permitting decision may petition for an administrative proceeding (hearing) in accordance with Section 120.57, F.S. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 2600 Blair Stone Road, Tallahassee, Florida 32399-2400. Petitions filed by the permit applicant and the parties listed below must be filed within 14 days of receipt of this intent. Petitions filed by other persons must be filed within 14 days of publication of the public notice or within 14 days of their receipt of this intent, whichever first occurs. Petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. Failure to file a petition within this time period shall constitute a waiver of any right such person may have to request an administrative determination (hearing) under Section 120.57, F.S.

The Petition shall contain the following information;

(a) The name, address, and telephone number of each petitioner, the applicant's name and address, the Department Permit File Number and the county in which the project is proposed;
(b) A statement of how and when each petitioner received notice of the Department's action or proposed action;
(c) A statement of how each petitioner's substantial interests are affected by the Department's action or proposed action;
(d) A statement of the material facts disputed by Petitioner, if any;
(e) A statement of facts which petitioner contends warrant reversal or modification of the Department's action or proposed action;
(f) A statement of which rules or statutes petitioner contends require reversal or modification of the Department's action or proposed action; and,
(g) A statement of the relief sought by petitioner, stating precisely the action petitioner wants the Department to take with respect to the Department's action or proposed action.

If a petition is filed, the administrative hearing process is designed to formulate agency action. Accordingly, the Department's final action may be different from the position taken by it in this intent. Persons whose substantial interests will be affected by any decision of the Department with regard to the application have the right to petition to become a party to the proceeding. The petition must conform to the requirements specified above and be filed (received) within 14 days of receipt of this intent in the Office of General Counsel at the above address of the Department. Failure to petition within the allowed time frame constitutes a waiver of any right such person has to request a hearing under Section 120.57, F.S., and to participate as a party to this proceeding. Any subsequent intervention will only be at the approval of the presiding officer upon motion filed pursuant to Rule 28-5.207, F.A.C.

Executed in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

C. H. Fancy, P.E., Chief
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399
904-488-1344

CERTIFICATE OF SERVICE

The undersigned duly designated deputy clerk hereby certifies that this INTENT TO ISSUE and all copies were mailed by certified mail before the close of business on 12/19/94 to the listed persons.

Clerk Stamp

FILING AND ACKNOWLEDGMENT
FILED, on this date, pursuant to §120.52(11), Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Charlotte J. Hayes 12/19/94
Clerk Date

Copies furnished to:

C. Kirts, NED
J. Harper, EPA
J. Bunyak, NPS
B. Oven, PPS, DEP
D. Graziani, P.E., FWI

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NOTICE OF INTENT TO ISSUE PERMIT

PSD-FL-212

The Department of Environmental Protection (Department) gives notice of its intent to issue a PSD permit to the Gainesville Regional Utilities (GRU) to construct a 74 MW simple cycle combustion turbine at GRU's existing facility. The facility is located off US 441 North in Alachua County, Florida. The project is subject to review under the Prevention of Significant Deterioration (PSD) regulations for the following pollutants: sulfur dioxide, nitrogen oxides, sulfuric acid mist and particulate matter. A determination of Best Available Control Technology (BACT) was required for these pollutants. The maximum predicted increases in ambient sulfur dioxide, nitrogen dioxide, and particulate matter concentrations due to this project are all less than the respective PSD Class I and II significant impact levels; thus, no PSD increment consumption was calculated for this project. The Department is issuing this Intent to Issue for the reasons stated in the Technical Evaluation and Preliminary Determination.

A person whose substantial interests are affected by the Department's proposed permitting decision may petition for an administrative proceeding (hearing) in accordance with Section 120.57, Florida Statutes (F.S.). The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 2600 Blair Stone Road, Tallahassee, Florida 32399-2400, within 14 days of publication of this notice. Petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. Failure to file a petition within this time period shall constitute a waiver of any right such person may have to request an administrative determination (hearing) under Section 120.57, F.S.

The Petition shall contain the following information; (a) The name, address, and telephone number of each petitioner, the applicant's name and address, the Department Permit File Number and the county in which the project is proposed; (b) A statement of how and when each petitioner received notice of the Department's action or proposed action; (c) A statement of how each petitioner's substantial interests are affected by the Department's action or proposed action; (d) A statement of the material facts disputed by Petitioner, if any; (e) A statement of facts which petitioner contends warrant reversal or modification of the Department's action or proposed action; (f) A statement of which rules or statutes petitioner contends require reversal or modification of the Department's action or proposed action; and, (g) A statement of the relief sought by petitioner, stating precisely the action petitioner wants the Department to take with respect to the Department's action or proposed action.

If a petition is filed, the administrative hearing process is designed to formulate agency action. Accordingly, 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 decision of the Department with regard to the application have the right to petition to become a party to the proceeding. The petition must conform to the requirements specified above and be filed (received) within 14 days of publication of this notice in the Office of General Counsel at the above address of the Department. Failure to petition within the allowed time frame constitutes a waiver of any right such person has to request a hearing under Section 120.57, F.S., and to participate as a party to this proceeding. Any subsequent intervention will only be at the approval of the presiding officer upon motion filed pursuant to Rule 28-5.207, Florida Administrative Code.

The application 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:

Department of Environmental Protection
Bureau of Air Regulation
111 S. Magnolia Drive, Suite 4
Tallahassee, Florida 32301

Department of Environmental Protection
Northeast District
7825 Baymeadows Way, Ste. B200
Jacksonville, Florida 32256-7577

Department of Environmental Protection
Northeast District Branch Office
5700 Southwest 34th Street, Suite 1204
Gainesville, Florida 32608

Any person may send written comments on the proposed action to Mr. John Brown at the Department's Tallahassee address. All comments received within 30 days of the publication of this notice will be considered in the Department's final determination.

Further, a public hearing can be requested by any person(s). Such requests must be submitted within 30 days of this notice.

Technical Evaluation
and
Preliminary Determination

Gainesville Regional Utilities
Deerhaven Generating Station
Gainesville, Alachua County, Florida

74 MW Simple Cycle Combustion Turbine

Permit Number: PSD-FL-212

Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation

December 16, 1994

SYNOPSIS OF APPLICATION

I. NAME AND ADDRESS OF APPLICANT

City of Gainesville, Gainesville Regional Utilities
P. O. Box 147117, Station A-134
Gainesville, Florida 32614-7117

II. FACILITY INFORMATION

II.1 Facility Location

This facility is located at its existing Deerhaven site approximately seven miles north of Gainesville, in Alachua County, Florida. The UTM coordinates are Zone 17, 365.5 km East and 3292.7 km North.

II.2 Facility Identification Code (SIC)

Major Group No. 49 - Electric, Gas and Sanitary Services.

Industry Group No. 491 - Combination Electric, Gas and Other Utility Services.

Industry Group No. 4911 - Electric and Other Services Combined.

II.3 Facility Category

Gainesville Regional Utilities is classified as a major emitting facility. The proposed project, a 74 MW nominal/dual fuel simple cycle combustion turbine (CT), will increase emissions approximately by 239 tons per year (TPY) of nitrogen oxides (NO_x); 79 TPY of sulfur dioxide (SO_2); 96 TPY of carbon monoxide (CO); 22 TPY of particulate matter (PM); 7 TPY of PM less than 10 microns in diameter (PM_{10}); 9 TPY of volatile organic compounds (VOC); 0.00032 TPY of beryllium (Be); 0.0638 TPY of lead (Pb); 0.001 TPY of mercury (Hg); and 9 TPY of sulfuric acid (H_2SO_4) mist, if the combustion turbine is operated at 3900 total hours per year and up to 2000 hours per year on No. 2 fuel oil (max. 0.05% Sulfur content, by weight) at 100% load.

III. PROJECT DESCRIPTION

The proposed project will consist of the construction of a new simple cycle CT at the existing Deerhaven Generating Station. It will be designated as DHCT3. The new CT will provide a nominal 74 MW of additional generating capacity to the site. The CT will fire natural gas and No. 2 fuel oil (max. 0.05% Sulfur content, by weight) and will function as an intermediate peaking unit, operating no more than 3,900 total hours per year. The CT selected is a General Electric (GE) Model MS7001EA dry low NO_x unit. It will be capable of operating in any of these two modes: natural gas firing (NGF) or distillate fuel oil firing (FOF).

During NGF operations, oxides of nitrogen (NO_x) emissions will be controlled through the use of staged combustion with GE dry low NO_x combustors. During FOF operation, NO_x emissions will be controlled by the use of water injection to reduce peak flame temperature. The SO_2 and H_2SO_4 mist emissions will be controlled through the use of natural gas and by limiting the use of low sulfur fuel oil to no more than 2,000 hours per year. The CO, VOC and PM emissions will be controlled through good combustion practices. PM emissions will be further reduced by filtering the combustion air.

The existing Deerhaven Generating Station consists of two steam generating units [a nominal 81 MW gas/oil fired unit (Unit 1) and a nominal 235 MW coal fired unit (Unit 2)], and two nominal 22 MW gas/oil fired CTs, designated DHCT1 and DHCT2. The coal fired unit was licensed through the Florida Power Plant Siting Act (PPSA) process jurisdiction. The addition of the new gas/oil fired CT is being treated as a modification of the 1978 site certification.

IV. RULE APPLICABILITY

The proposed project, construction of a 74 MW simple cycle CT, is subject to preconstruction review under the provisions of Chapter 403, Florida Statutes, Chapters 62-4 and 62-210, 62-212, 62-272, 62-275, 62-296 and 62-296, Florida Administrative Code (F.A.C.).

This facility is located in an area designated attainment for all criteria pollutants in accordance with Rule 62-275.400, F.A.C.

The proposed emission unit is subject to the Prevention of Significant Deterioration (PSD) regulation (62-212.400, F.A.C.) because the requested increase in SO_2, NO_x, PM_{10} and H_2SO_4 exceed the significant emission rates (Table 400-2, Rule 62-212.400, F.A.C.). The allowable emission limitations/standards of the pollutants with significant emissions rate increases will be established by a Best Available Control Technology (BACT) determination (Rule 62-212.410, F.A.C.). The proposed emission unit is also subject to the applicable requirements of the federal Standards of Performance for New Stationary Sources (NSPS) for Gas Turbines, 40 CFR 60, Subpart GG, adopted by reference pursuant to Rule 62-296.800, F.A.C.

The proposed emission unit shall be in compliance with all applicable provisions of Chapters 62-212 through 297 and 62-4, F.A.C., and the 40 CFR 60 (July, 1993 version). The proposed emission unit shall be in compliance with all applicable provisions of Rules 62-210.650, F.A.C.: Circumvention; 62-210.700, F.A.C.: Excess Emissions; 62-296.800, F.A.C.: NSPS; Chapter 62-297, F.A.C.: Stationary Sources - Emissions Monitoring; and, 62-4.130, F.A.C.: Plant Operation - Problems.

V. SOURCE IMPACT ANALYSIS

The proposed 74 MW simple cycle CT will be capable of burning either natural gas or No. 2 fuel oil and will use dry low NO_x combustion technology or water injection, respectively, to control NO_x emissions; and, good combustion practices for VOC and CO control. The SO_2 and the H_2SO_4 mist emissions will be controlled by the use of low sulfur fuel oil (max. 0.05% sulfur content, by weight). Compliance with the BACT SO_2 emission standard will be demonstrated by fuel analysis. The PM_{10} BACT emissions standard/ limitation is met through filtering the combustion air, good combustion practices, the use of natural gas and limited low sulfur fuel oil firing.

V.1 **Emission Limitations**

The operation of this emissions unit burning distillate fuel oil or natural gas will produce emissions of NO_x, SO_2, CO, VOC, H_2SO_4, PM/PM_{10}, As, Fluorides, Be, Pb and Hg. Table 1 lists each pollutant subject to an emission limit and its allowable emission rates. Table 2 summarizes the potential emissions of pollutants not subject to a BACT determination.

TABLE 1. MAXIMUM ALLOWABLE EMISSION LIMITS

POLLUTANT	FUEL	BACT STANDARD	LBS/HR[1]	TPY
NO_x	Gas	15 ppmvd @ 15% Oxygen	58	113[2]
	Oil	42 ppmvd @ 15% Oxygen	184	184[3]
			Combined[4]	239
PM_{10}	Gas	Good combustion; visible emissions shall not exceed 10% opacity	7[5]	14[2,5]
	Oil	Good combustion of low sulfur oil; visible emissions shall not exceed 10% opacity	15[5]	15[3,5]
			Combined[4]	22
SO_2	Gas	Good combustion	29[5]	57[2,5]
	Oil	Good combustion of low sulfur fuel oil: max. 0.05% sulfur content, by weight	53[5]	53[3,5]
			Combined[4]	81
	Oil	Good combustion, limited quantity: max. 0.25% sulfur content, by weight		
H_2SO_4 Mist	Gas	Good combustion	3[5]	6[2,5]
	Oil	Good combustion of low sulfur fuel oil: max. 0.05% sulfur content, by weight	6[5]	6[3,5]
			Combined[4]	9
	Oil	Good combustion, limited quantity: max. 0.25% sulfur content, by weight		

1. These values are calculated using F-factors.
2. Based on a maximum of 3900 hours of operation with natural gas firing.
3. Based on a maximum of 2000 hours of operation with fuel oil firing.
4. Based on 1900 hours natural gas firing and 2000 hours of operation with fuel oil firing.
5. Compliance shall be demonstrated through fuel sulfur analysis.

TABLE 2. ESTIMATED POTENTIAL EMISSIONS

POLLUTANT	METHOD OF CONTROL	TPY[6]
CO	Good combustion, proper use of water injection system	95.4
VOC	Good combustion	8.9
Inorganic Arsenic	Natural Gas/No. 2 Fuel Oil	0
Mercury	Natural Gas/No. 2 Fuel Oil	0.001
Pb	Natural Gas/No. 2 Fuel Oil	0.0638
Be	Natural Gas/No. 2 Fuel Oil	0.00033

6. TPY values are for annual operation reports (AOR) and PSD applicability determinations. These values are based on the DHCT3 operating at full load at ISO for a total of 3900 hours per year, with up to 2000 hours of No. 2 fuel oil-fired operation.

V.2 Air Quality Report

a. Introduction

The proposed project will emit four pollutants in PSD significant amounts. These pollutants are NO_x, SO_2, and PM_{10}, along with the non-criteria pollutant H_2SO_4 mist.

The air quality impact analyses required by the PSD regulations for these pollutants include:

* An analysis of existing air quality;
* A PSD increment analysis (SO_2 and NO_2);
* An Ambient Air Quality Standards (AAQS) analysis;
* An analysis of impacts on soils, vegetation, and visibility and of growth-related air quality modeling impacts; and
* A "Good Engineering Practice" (GEP) stack height determination.

The analysis of existing air quality generally relies on preconstruction monitoring data collected with EPA-approved methods. The PSD increment and AAQS analyses depend on air quality dispersion modeling carried out in accordance with EPA guidelines.

Based on the 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 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 Florida Department of Environmental Protection 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 discussion of the general modeling approach and required analyses follows.

b. Analysis of Existing Air Quality and Determination of Background Concentrations

Preconstruction ambient air quality monitoring is required for all pollutants subject to PSD review. However, an exemption to the monitoring requirement can 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 minimus concentration. Pollutants which do not have a specified de minimus level may also be exempt from preconstruction monitoring requirements. In addition, if an acceptable ambient monitoring method for the pollutant has not been established by EPA, monitoring is not required.

Even if preconstruction ambient monitoring is exempted, determination of background concentrations for PSD significant pollutants may be necessary for use in the AAQS analysis for each pollutant. These concentrations may be established from the required preconstruction ambient air quality monitoring analysis or from previously existing representative monitoring data. These background ambient air quality concentrations are added to pollutant impacts predicted by modeling and represent the air quality impacts of emissions units not included in the modeling.

Table 3 shows that NO_2, SO_2, and PM_{10} impacts from the project are predicted to be less than the de minimus concentrations. Therefore, preconstruction ambient air quality monitoring is not required for these three pollutants. There are no monitoring de minimus concentrations for H_2SO_4 mist; therefore, no preconstruction monitoring is necessary for this pollutant.

Furthermore, the results presented later in the significant impact analysis section of this air quality report show that NO_2, SO_2, and PM_{10} impacts from this project are not predicted to be greater than the significant impact levels; therefore, no AAQS analyses are required for these pollutants and no background concentrations need to be determined for this project.

c. Air Quality Modeling Approach

The EPA-approved Industrial Source Complex Short-Term (ISCST2) dispersion model was used to evaluate the pollutant emissions from the proposed emissions unit and other existing major facilities. The 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 ISCST2 model allows for the separation of emissions units, 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 emissions units for which downwash was considered.

Table 3. Maximum Air Quality Impacts for Comparison to the De Minimus Concentrations.

Pollutant	Avg. Time	Predicted Impact (ug/m^3)	De Minimus Conc. (ug/m^3)
NO_2	Annual	0.02	14
SO_2	24-hour	1.5	13
PM_{10}	24-hour	0.1	10

Table 4. Significant Impact Analysis

Pollutant	Averaging Time	Max. Predicted Impact (ug/m^3)	Significant Impact Level (ug/m^3)
NO_2	Annual	0.02	1
SO_2	Annual	0.02	1
	24-hour	1.48	5
	3-hour	4.16	25
PM_{10}	Annual	0.002	1
	24-hour	0.1	5

Initially, the applicant conducted preliminary modeling for the purpose of determining the worst case fuel/load/temperature scenarios for the proposed CT. These modeling runs were conducted using one year of meteorology (1988) at three ambient temperatures (95°F, 75°F, and 20°F) and three CT loads (100%, 80%, and 60%) for both natural gas and distillate fuel oil. In addition, a modeling run was conducted for the CT power augmentation mode at 95°F and 100% load. As a result of these preliminary runs, the applicant determined that there were four different temperature and load combinations which caused the "worst case" ground-level ambient air quality impacts for the different averaging periods and pollutants. These "worst case" conditions were used as input in the significant impact analysis. Maximum predicted concentrations from the proposed project alone were predicted at 900 receptors located in a radial grid centered on the proposed combustion turbine. Receptors were established in 25 concentric rings located at the following distances from the proposed CT: 1.0, 1.5, 2.0, 2.5, 3.0, 3.5, 4.0, 4.5, 5.0, 5.5, 6.0, 7.0, 8.0, 9.0, 10.0, 11.0, 12.0, 13.0, 14.0, 15.0, 16.0, 17.0, 18.0, 19.0, and 20.0 km. Each ring contained 36 receptors spaced at 10-degree intervals. Receptors from these polar grids which fell within the project site boundaries were not included in the analysis; however, 26 additional receptors were placed around the site boundary. In addition, receptors were placed around the perimeter of the Alachua County Public Works facility located within the project site boundary and at a security officer's residence which is also located within the site boundary. Based on the results from the significant impact analysis, no further AAQS or PSD Class II modeling analyses were required.

There are two PSD Class I areas located near this emissions unit, the Chassahowitzka National Wilderness Area (CWNA) and the Okefenokee National Wilderness Area (OWNA). The CWNA is located 110 to 129 km south of the project site while the OWNA is located 90 to 145 km north of the site. In the PSD Class I analysis, the CWNA is represented by 13 Department-approved standard discrete receptors and the OWNA by 10 Department-approved standard discrete receptors.

Meteorological data used in the ISCST2 model to determine air quality impacts consisted of a concurrent 5-year period (1985-1989) of hourly surface weather observations from the National Weather Service (NWS) station at the Gainesville Regional Airport and twice-daily upper air soundings from the NWS station at Tampa (Ruskin). The surface observations included wind direction, wind speed, temperature, cloud cover and cloud ceiling.

Since five years of data were used, the highest-second-high (HSH) short-term predicted concentrations were compared with the appropriate ambient air quality standards or PSD increments. For the annual averages, the highest predicted yearly average was compared with the standards. For determining the significant impact area, if any, both the highest short-term predicted concentrations and the highest predicted yearly averages were compared to the significant impact levels.

d. Significant Impact Analysis

As shown in Table 4, the maximum predicted air quality impacts due to NO_x, SO_2, and PM_{10} emissions from the proposed project are less than the respective significant impact levels for these pollutants. Therefore no further AAQS or PSD Class II modeling analyses were required.

e. PSD Class I Increment Analysis

A proposed emissions unit subject to PSD review must conduct a dispersion modeling analysis of its impacts on any PSD Class I areas located near the source. There are two PSD Class I areas located near this emissions unit, as discussed in the air quality modeling approach section. The modeling results for these two areas are summarized in Table 5. As indicated in this table, the maximum predicted impacts of NO_2, SO_2, and PM_{10} are all below the respective National Park Service significant impact levels. Consequently, the impacts of the proposed project will be well below the applicable PSD Class I increments for these pollutants.

f. Air Toxics Analysis

The maximum impacts of regulated and non-regulated toxic air pollutants that will be emitted by this proposed project are presented in Table 6. Each pollutant's maximum 8-hour, 24-hour, and annual impact is compared to the Acceptable Ambient Concentrations (AAC). The table shows that all toxic pollutant impacts will be below their respective AACs.

V.3 Additional Impacts Analysis

a. Impacts on Soils, Vegetation, and Wildlife

The maximum predicted ground-level concentrations due to NO_x, SO_2, and PM_{10} emissions from the proposed project are less than the PSD significant impact levels. As such, this project is not expected to have a harmful impact on soils, vegetation, and wildlife in the PSD Class II area. In addition, no significant impacts are expected in the two nearby PSD Class I areas.

b. Impact on Visibility

Visual Impact Screening and Analysis (VISCREEN), the EPA-approved Level I visibility computer model was used to estimate the impact of the proposed project's stack emissions on visibility in the CWNA and OWNA PSD Class I areas.

Table 5. PSD Class I Increment Analysis

Pollutant	Averaging Time	Max. Predicted Impact (ug/m^3) CWNA	Max. Predicted Impact (ug/m^3) OWNA	National Park Service Significant Impact Level (ug/m^3)
NO_2	Annual	0.0047	0.0047	0.025
SO_2	Annual	0.00182	0.00182	0.025
	24-hour	0.063	0.068	0.07
	3-hour	0.303	0.267	0.48
PM_{10}	Annual	0.0003	0.0003	0.08
	24-hour	0.018	0.019	0.33

Table 6. Air Toxics Analysis

	8- hour		24- hour		Annual	
Pollutant	Impact (ug/m^3)	AAC (ug/m^3)	Impact (ug/m^3)	AAC (ug/m^3)	Impact (ug/m^3)	AAC (ug/m^3)
Antimony	0.0004	5	0.0002	1.2	0.000002	0.3
Arsenic	0.00009	2	0.00004	0.48	0.0000005	0.000230
Beryllium	0.000006	0.02	0.000003	0.0048	0.00000003	0.00042
Cadmium	0.00008	0.5	0.00004	0.12	0.0000004	0.00056
Chromium+6	0.0009	0.5	0.0004	0.12	0.000005	0.000083
Cobalt	0.0002	0.5	0.00008	0.12	-	-
Formaldehyde	0.078	12	0.035	2.88	0.0008	0.077
Lead	0.001	0.5	0.0005	0.12	0.000006	0.09
Manganese	0.006	50	0.003	12	-	-
Mercury	0.00002	0.5	0.000008	0.12	0.00000009	0.3
Nickel	0.023	0.5	0.011	0.12	0.0002	0.0042
Selenium	0.00001	2	0.000004	0.48	-	-

Note: AAC = Acceptable Ambient Concentration

The results indicate that the maximum visibility impacts caused by the proposed emissions unit do not exceed the screening criteria inside or outside the CWNA and OWNA Class I areas. As a result, there is no significant impact on visibility predicted for either Class I area.

c. Growth-Related Air Quality Impacts

There will be a small number of temporary construction workers during construction. However, there will be no significant impacts on air quality caused by associated population growth.

d. GEP Stack Height Determination

Good Engineering Practice (GEP) stack height means the greater of: (1) 65 m (213 ft); or, (2) the maximum nearby building height plus 1.5 times the building height or width, whichever is less.

The CT structure is the most significant structure associated with the proposed project. The GEP stack height calculated for the CT stack is 38m. The proposed stack height for the CT is 15.8 m; therefore, the CT stack will not exceed the GEP stack height.

VI. CONCLUSION

Based on the information provided by Gainesville Regional Utilities, the Department has reasonable assurance that the proposed installation of the 74 MW simple cycle CT, as described in this evaluation, and subject to the conditions proposed herein, will not cause or contribute to a violation of any air quality standard, PSD increment, or any other technical provision of Chapters 62-212 and 62-4 of the Florida Administrative Code.

John Brown
Dec 15 1994

FLORIDA

Department of Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

PERMITTEE:
Gainesville Regional Utilities
P. O. Box 147117, Station A-134
Gainesville, FL 32614-7117

Permit Number: PSD-FL-212
Expiration Date: June 30, 1996
County: Alachua
Latitude/Longitude: 29°45'32"N 82°23'26"W
Project: A 74 MW Simple Cycle Combustion Turbine (DHCT3)

This permit is issued under the provisions of Chapter 403, Florida Statutes (F.S.); Chapters 62-210 through 62-297 and 62-4, Florida Administrative Code (F.A.C.); and, 40 CFR 52.21 and 60. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawings, plans, and other documents attached hereto or on file with the Department of Environmental Protection (Department) and specifically described as follows:

Construction of a 74 MW simple cycle combustion turbine designed to burn natural gas and No. 2 fuel oil. Deerhaven combustion turbine (DHCT3) will be constructed/installed at the Gainesville Regional Utilities (GRU)'s existing facility that is located near U.S. 441/SR20/SR25. The UTM coordinates are Zone 17, 365.5 km East and 3292.7 km North.

The emissions unit shall be constructed in accordance with the permit application, plans, documents, amendments and drawings, except as otherwise noted in the General and Specific Conditions.

<u>Attachments are listed below:</u>

1. GRU's letter received October 20, 1993.
2. GRU's letter received December 29, 1993.
3. Construction Permit application received March 22, 1994.
4. Department's letter dated April 22, 1994.
5. GRU's letter with attachments received April 25, 1994.
6. GRU's letter with attachments received August 12, 1994.
7. GRU's letter with attachments received September 21, 1994.
8. Technical Evaluation and Preliminary Determination dated December 16, 1994.

GENERAL CONDITIONS:

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, F.S. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions.

2. This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings, exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.

3. As provided in Subsections 403.087(6) and 403.722(5), F.S., the issuance of this permit does not convey any 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 of or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in the permit.

4. This permit conveys no title to land or water, does not constitute State recognition or acknowledgement of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title.

5. This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, or plant life, or property caused by the construction or operation of this permitted source, or from penalties therefore; nor does it allow the permittee to cause pollution in contravention of F.S. and Department rules, unless specifically authorized by an order from the Department.

6. The permittee shall properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed or used by the permittee to achieve compliance with the conditions of this permit, as required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by Department rules.

7. The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law and at a

GENERAL CONDITIONS:

reasonable time, access to the premises, where the permitted activity is located or conducted to:

a. Have access to and copy any records that must be kept under the conditions of the permit;

b. Inspect the facility, equipment, practices, or operations regulated or required under this permit; and,

c. Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

Reasonable time may depend on the nature of the concern being investigated.

8. If, for any reason, the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit, the permittee shall immediately provide the Department with the following information:

a. a description of and cause of non-compliance; and,

b. the period of noncompliance, including dates and times; or, if not corrected, the anticipated time the non-compliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the non-compliance.

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

9. In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the F.S. or Department rules, except where such use is prescribed by Sections 403.73 and 403.111, F.S. Such evidence shall only be used to the extent it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

10. The permittee agrees to comply with changes in Department rules and F.S. after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by F.S. or Department rules.

11. This permit is transferable only upon Department approval in accordance with Rules 62-4.120 and 62-30.300, F.A.C., as applicable.

GENERAL CONDITIONS:

The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.

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

13. This permit also constitutes:

    (x) Determination of Best Available Control Technology (BACT)
    (x) Determination of Prevention of Significant Deterioration (PSD)
    (x) Compliance with New Source Performance Standards (NSPS)

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 for 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:

        - the date, exact place, and time of sampling or measurements;
        - the person responsible for performing the sampling or measurements;
        - the dates analyses were performed;
        - the person responsible for performing the analyses;
        - the analytical techniques or methods used; and,
        - the results of such analyses.

15. When requested by the Department, the permittee shall within a reasonable time furnish any information required by law which is needed to determine compliance with the permit. If the permittee

GENERAL CONDITIONS:

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.

SPECIFIC CONDITIONS:

General Operating Requirements

1. The maximum heat input rates, based on high heating values of each fuel, to the DHCT3 and at ISO conditions (i.e., 59° F, 60% relative humidity and 101.3 kilopascals pressure), shall not exceed 971.1 MMBTU/hr, while firing natural gas, nor 990.6 MMBTU/hr, while firing fuel oil. Heat input will vary depending on ambient conditions and the DHCT3 characteristics. Manufacturer's curves or equations for correction to other ambient conditions shall be provided to the Department of Environmental Protection (DEP) at least 90 days before initial compliance testing.

2. The DHCT3 is allowed to operate up to 3900 hours per year, but not to exceed 2000 hours while firing fuel oil.

3. Only natural gas (NG) or No. 2 fuel oil shall be fired in the combustion turbine. The maximum sulfur content of the fuel oil shall not exceed 0.05 percent, by weight. GRU has established that there is approximately 55 hours of full load operation of fuel oil, which contains nominally 0.25% sulfur content, by weight, remaining in the fuel storage tank. GRU will be allowed to deplete this reserve by firing the fuel oil in the DHCT3. However, all future deliveries of fuel oil for the DHCT3 shall meet the BACT requirement, which limits the fuel oil sulfur content to no more than 0.05%, by weight. Fuel sulfur content shall be determined and recorded each time fuel is transferred into the bulk storage tank(s).

4. 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 pursuant to Rule 62-296.310(3), F.A.C. - Unconfined Emissions of Particulate Matter.

5. Any change in the method of operation, equipment or operating hours, pursuant to Rule 62-212.200, F.A.C., Definitions - Modifications, shall be submitted in writing and/or on an application to the DEP's Bureau of Air Regulation office and Northeast District office.

SPECIFIC CONDITIONS:

Emission Limits

6. The maximum allowable emissions from the DHCT3, when firing natural gas or No. 2 fuel oil, in accordance with the BACT determination, and at 95 - 100% percent load based on the manufacturer's curves submitted to the DEP, shall not exceed the following limits except during periods of start up, shutdown, and malfunction pursuant to Rule 62-210.700, F.A.C.:

MAXIMUM ALLOWABLE EMISSION LIMITS

POLLUTANT	FUEL	BACT STANDARD	LBS/HR *	TPY
NO_x	Gas	15 ppmvd @ 15% Oxygen	58	113(a)
	Oil	42 ppmvd @ 15% Oxygen	184	184(b)
			Combined(c)	239
PM_{10}	Gas	Good combustion; visible emissions shall not exceed 10% opacity	7(d)	14(a)(d)
	Oil	Good combustion of low sulfur oil; visible emissions shall not to exceed 10% opacity	15(d)	15(b)(d)
			Combined(c)	22
SO_2	Gas	Good combustion	29(d)	57(a)(d)
	Oil	Good combustion of low sulfur fuel oil: max. 0.05% sulfur content, by weight	53(d)	53(b)(d)
			Combined(c)	81
	Oil	Good combustion, limited quantity: max. 0.25% sulfur content, by weight		
H_2SO_4 Mist	Gas	Good combustion	3(d)	6(a)(d)
	Oil	Good combustion of low sulfur fuel oil: max. 0.05% sulfur content, by weight	6(d)	6(b)(d)
			Combined(c)	9
	Oil	Good combustion, limited quantity: max. 0.25% sulfur content, by weight		

*These values are calculated using F factors.
(a) Based on a maximum of 3900 hours of operation with natural gas firing.
(b) Based on a maximum of 2000 hours of operation with fuel oil firing.
(c) Based on 1900 hours natural gas firing and 2000 hours of operation with fuel oil firing.
(d) Compliance shall be demonstrated through fuel sulfur analysis.

SPECIFIC CONDITIONS:

7. Visible emissions shall not exceed 10% opacity when firing natural gas or No. 2 fuel oil.

8. The potential emissions projected from the DHCT3 are:

ESTIMATED POTENTIAL EMISSIONS

Pollutant	Method of Control	TPY **
CO	Good combustion, proper use of water injection system	95.4
VOC	Good combustion	8.9
Inorganic Arsenic	Natural Gas/No. 2 Fuel Oil	0
Mercury	Natural Gas/No. 2 Fuel Oil	0.001
Pb	Natural Gas/No. 2 Fuel Oil	0.0638
Be	Natural Gas/No. 2 Fuel Oil	0.00033

** TPY values are for annual operation reports (AOR) and PSD applicability determinations. These values are based on the DHCT3 operating at full load at ISO for a total of 3900 hours per year, with up to 2000 hours of No. 2 fuel oil-fired operation.

Compliance Determination

9. Compliance with the allowable emission limiting standards shall be determined within 60 days after achieving the maximum production rate at which this unit will be operated, but not later than 180 days of initial operation at the maximum capability of the unit and annually thereafter, by using the following reference methods as described in 40 CFR 60, Appendix A (1993 version), and adopted by reference in Chapter 62-297, F.A.C.

Initial (I) compliance tests shall be performed on the DHCT3 while firing each fuel (gas, oil). Annual (A) compliance tests shall be performed during every federal fiscal year (October 1 - September 30) pursuant to Rule 62-297.340, F.A.C., on the DHCT3 with the fuel(s) used for more than 400 hours in the preceding 12-month period.

- Method 9 Visual Determination of the Opacity of Emissions from Stationary Sources (I,A)

SPECIFIC CONDITIONS:

- Method 10 Determination of Carbon Monoxide Emissions from Stationary Sources (I)

- Method 20 Determination of Nitrogen Oxides and Diluent Emissions from Stationary Gas Turbines (I,A)

Note: No other methods may be used for compliance testing unless prior DEP approval is received in writing. The DEP may request a special compliance test pursuant to Rule 62-297.340(2), F.A.C., when, after investigation (such as complaints, increased visible emissions, or questionable maintenance of control equipment), there is reason to believe that any applicable emission standard is being violated.

10. Notwithstanding the requirements of Rule 62-297.340, F.A.C., the exclusive use of fuel oil with a maximum sulfur content limit of 0.05% or less, by weight, is the method for determining compliance for SO_2, H_2SO_4 mist, and PM_{10}. There is no suitable method for the testing of PM_{10} from this type of emissions unit, and the SO_2 and H_2SO_4 emissions are clearly limited by the sulfur content of the fuel. Compliance with the SO_2 and sulfuric acid mist emission limits shall be determined by fuel oil analysis using ASTM D2880-71 or D4294 (or equivalent) for the sulfur content of liquid fuels and D1072-80, D3031-81, D4084-82 or D3246-81 (or equivalent) for sulfur content of gaseous fuel. Alternatively, natural gas supplier data for sulfur content may be submitted. However, the applicant is responsible for ensuring that the procedures above are used for determination of fuel sulfur content. 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 pursuant to 40 CFR 60.335(e) (1993 version).

11. Pursuant to Rule 62-212.410, F.A.C., the permittee shall install a dry low-NO_x combustor on the DHCT3 for NO_x control when firing natural gas. Control of NO_x when firing No. 2 fuel oil shall be accomplished by water injection.

12. An initial test for CO, concurrent with each NO_x test, is required to confirm that annual potential emissions will not exceed 100 TPY. The NOx and initial CO test results shall be the average of three valid one-hour runs. The DEP's Northeast District office shall be notified, in writing, at least 30 days prior to the initial compliance tests and at least 15 days before annual compliance test(s). The combustion turbine shall operate between 95% and 100% of maximum capacity for the ambient conditions experienced during compliance test(s). The turbine manufacturer's heat input rates (based on the high heating value of the fuel) vs. ambient temperature curve shall be included with the compliance

SPECIFIC CONDITIONS:

test results. The fuel feed rates and the high heating value of the fuels shall be established during the initial and annual compliance tests. Compliance test results shall be submitted to the DEP's Northeast District office no later than 45 days after completion of the last test run.

13. Excess NO_X emissions from this turbine resulting from startup, shutdown, malfunction, fuel switching or load change, shall be acceptable providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24-hour period unless specifically authorized by the DEP's Bureau of Air Regulation or the Northeast District office for a longer duration. Best operating practices shall be documented in writing and a copy submitted to the DEP's Northeast District office along with the initial compliance test data. The document may be updated as needed with all updates submitted to the DEP's Northeast District office within thirty (30) days of implementation and shall include time limitations on excess emissions caused by turbine startup.

Notification, Reporting and Recordkeeping

14. Notification and recordkeeping shall be in accordance with 40 CFR 60.7 (1993 version). The following protocols shall be submitted to the DEP's Northeast District office for approval:

a. CEMS - If applicable, the Federal Acid Rain Program requirements of 40 CFR 75 shall apply when those requirements become effective in Florida.

b. Performance Test Protocol - At least 30 days prior to conducting the initial performance tests required by this permit, the permittee shall submit to the DEP's Northeast District office for their review and approval: a protocol outlining the procedures to be followed; the test methods; and, any differences between the reference methods and the test methods proposed to be used to verify compliance with the conditions of this permit.

c. All measurements, records, and other data required to be maintained by GRU shall be retained for at least five (5) years following the date on which such measurements, records, or data are recorded. These data shall be made available to the DEP representatives.

Monitoring Requirements

15. The permittee shall install, calibrate, maintain, and operate a continuous emission monitor in the stack to measure and record the

SPECIFIC CONDITIONS:

nitrogen oxides emissions from this source. One-hour periods when NO_x emissions (ppmvd @ 15% oxygen) are above the BACT standards (15/42 gas/oil) shall be reported as excess emissions following the format of 40 CFR 60.7 (1993 version). The continuous emission monitor must comply with Rule 62-297.500, F.A.C.; 40 CFR 60, Appendix F, Quality Assurance Procedures (1993 version) (or other DEP approved QA plan); 40 CFR 60, Appendix B, Performance Specification 2 (1993 version); or, if applicable, 40 CFR 75, Appendix A and Appendix B. Periods of startup, shutdown, fuel switching, malfunction, and load change shall be monitored and recorded. The NO_x CEMS will be used in lieu of the water/fuel monitoring system and fuel bound nitrogen (FBN) monitoring, which are required in accordance with 40 CFR 60, Subpart GG (1993 version), and are used as indicators of compliance with the NO_x standard specified in the subpart. Since the NO_x emission standard from Subpart GG is more than twice the BACT standard, monitoring for emissions in excess of the BACT limits using the NO_x CEMS is more stringent. FBN levels are not required for excess emission reports when excess emissions are reported and based on the stack monitoring system. The calibration of the water/fuel monitoring device required in 40 CFR 60.335(c)(2) (1993 version) will be replaced by certification tests of the NO_x CEMS.

16. A malfunction means any sudden and unavoidable failure of air pollution control equipment or process equipment to operate in a normal or usual manner. Failures that are caused entirely or in part by poor maintenance, careless operation, or any other preventable upset condition or preventable equipment breakdown shall not be considered malfunctions and shall be prohibited pursuant to Rule 62-210.700, F.A.C.

17. The sulfur content of the fuel oil being fired in the combustion turbine shall be determined in accordance with 40 CFR 60.334(b) (1993 version). Any request for a future custom monitoring schedule shall be made in writing and directed to the DEP's Bureau of Air Regulation office. Any custom schedule approved by the DEP pursuant to 40 CFR 60.334(b) (1993 version) will be recognized as enforceable provisions of the permit, provided that the holder of this permit demonstrates that the provisions of the schedule will be adequate to assure continuous compliance. The records of natural gas and No. 2 fuel oil usage shall be kept by the company for a five-year period for regulatory agency inspection purposes.

Rule Requirements

18. The emission unit shall be in compliance with all applicable provisions of Chapter 403, F.S., and Chapters 62-4, 210, 212, 275, 296 and 297, F.A.C.

SPECIFIC CONDITIONS:

19. The emission unit shall be in compliance with all applicable requirements of 40 CFR 60, Subpart A, Appendix A and Appendix B (1993 version), Subpart GG - Standards of Performance for Stationary Gas Turbines (1993 version), and Rule 62-296.800(2)(a), 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). All notifications and reports required by this specific condition shall be submitted to the DEP's Northeast District office.

20. Issuance of this permit does not relieve the facility owner or operator from compliance with any applicable federal, state, or local permitting requirements and regulations (Rule 62-210.300(1), F.A.C.).

21. The emission unit shall be in compliance with all applicable provisions of Rule 62-210.650, F.A.C.: Circumvention; Rule 62-210.700, F.A.C.: Excess Emissions; Rule 62-296.800, F.A.C.: Standards of Performance for New Stationary Sources (NSPS); Chapter 62-297, F.A.C.: Stationary Sources - Emissions Monitoring; and, Rule 62-4.130, F.A.C.: Plant Operation - Problems.

22. If construction does not commence within 18 months of issuance of this permit, the permittee shall obtain from the DEP's Bureau of Air Regulation a review and, if necessary, a modification of the BACT determination and allowable emissions for the unit(s) on which construction has not commenced (40 CFR 52.21(r)(2) (1993 version)).

23. Quarterly excess emission reports, in accordance with 40 CFR 60.7 and 60.334 (1993 version), shall be submitted to the DEP's Northeast District office.

24. Pursuant to Rule 62-210.370(2), F.A.C., Annual Operating Reports, the permittee is required to submit annual reports on the actual operating rates and emissions from this facility. These reports shall include, but are not limited to the following: sulfur content of the fuel being fired, fuel usage, hours of operation, air emissions limits, etc. Annual operating reports shall be sent to the DEP's Northeast District office by March 1st of each calendar year.

25. Stack sampling facilities shall be installed in accordance with Rule 62-297.345, F.A.C.

26. The permittee, for good cause, may request that this construction 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 (Rule 62-4.090, F.A.C.).

SPECIFIC CONDITIONS:

27. An application for an operation permit must be submitted to the Northeast District office at least 90 days prior to the expiration date of this construction permit. To properly apply for an operation permit, the permittee shall submit the appropriate application form, fee, certification that construction was completed noting any deviations from the conditions in the construction permit, and compliance test reports as required by this permit (Rules 62-4.055 and 62-4.220, F.A.C.).

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

____
Virginia B. Wetherell
Secretary

Best Available Control Technology (BACT) Determination
Gainesville Regional Utilities
Alachua County

PSD-FL-212

Gainesville Regional Utilities (GRU) proposes to construct a 74 MW (nominal) simple cycle combustion turbine (CT) at the existing Deerhaven site approximately seven miles north of Gainesville in Alachua County. The selected CT, designated as DHCT3, is a GE Model MS 7001 EA with dry low-NO_x combustors and will also use water injection for NO_x control when firing fuel oil.

The applicant requested approval to operate the emission unit for 3900 hours per year, as indicated in the table below. The No. 2 fuel oil will have a maximum limit of 0.05 percent sulfur content, by weight. The applicant has indicated the maximum annual tonnage of regulated air pollutants emitted from the combustion turbine at 100 percent load, at 15% O_2 and ISO conditions (59°F, 60% relative humidity, and 101.3 kilopascals pressure), for each type of fuel fired, to be as follows:

Pollutant	Emissions (TPY) Gas	Gas w/PA *	Oil	Total	PSD Significant Emission Rate (TPY)
	1510 Hrs	390 Hrs	2000 Hrs		
NO_x	40	23	213	276	40
SO_2	20	6	48	74	40
PM/PM_{10}	5	1	15	21	25/15
CO	24	8	65	97	100
VOC	2	1	6	9	40
H_2SO_4 mist	2	1	5	8	7
Be			0.00033	0.00033	0.0004
Hg			0.001	0.001	0.1
Pb			0.0638	0.0638	0.6
As			0	0	0

* with power augmentation

Rule 62-212.400(2)(f)(1), Florida Administrative Code (F.A.C.), requires a BACT review for all regulated pollutants emitted in an amount equal to or greater than the significant emission rates listed in the table above. Therefore, BACT is required for NO_x, SO_2, PM_{10}, and H_2SO_4 mist.

<u>Date of Receipt of a BACT Application</u>

March 25, 1994

BACT Determination Requested by the Applicant

Pollutant	Proposed Limits
NO_x	15 ppmvd @ 15% O_2 (natural gas firing) 54 ppmvd @ 15% O_2 (for No. 2 fuel oil firing), maximum based on fuel bound nitrogen 30 ppmvd @ 15% O_2 (natural gas firing-power augmentation mode). Dry low-NOx combustor when firing natural gas and water injection when firing distillate oil and during power augmentation mode.
PM_{10}	Prefiltering of the combustion air, good combustion practices, and use of natural gas as the primary fuel with limited annual fuel oil firing.
SO_2	0.05% sulfur content by weight (fuel oil firing); also, an equivalent of up to 55 hours of full load operation at ISO conditions using a fuel oil with a maximum of 0.25% sulfur content, by weight.
H_2SO_4 Mist	0.05% sulfur by weight (fuel oil firing), also, an equivalent of up to 55 hours of full load operation at ISO conditions using a fuel oil with a maximum of 0.25% sulfur content, by weight.

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:

(a) 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).

(b) All scientific, engineering, and technical material and other information available to the Department.

(c) The emission limiting standards or BACT determination of any other state.

(d) 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 infeasible 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.

The air pollutant emissions from simple cycle combustion turbines can be grouped into categories based upon the control equipment and techniques that are available to control emissions from these emission units. Using this approach, the emissions can be classified as follows:

- Combustion Products (e.g., particulate matter). Controlled generally by good combustion of clean fuels.
- Products of Incomplete Combustion (e.g., carbon monoxide). Control is largely achieved by proper combustion techniques.
- Acid Gases (e.g., nitrogen oxides). Controlled generally by gaseous control devices.

Grouping the pollutants in this manner facilitates the BACT analysis because it enables the equipment available to control the type or group of pollutants emitted and the corresponding energy, economic, and environmental impacts to be examined on a common basis. Although all of the pollutants addressed in the BACT analysis may be subject to a specific emission limiting standard as a result of PSD review, the control of "nonregulated" air pollutants is considered in imposing a more stringent BACT limit on a "regulated" pollutant (i.e., particulate matter, sulfur dioxide, fluorides, sulfuric acid mist, etc,), if a reduction in "nonregulated" air pollutants can be directly attributed to the control device selected as BACT for the abatement of the "regulated" pollutants.

<u>ACID GASES</u>

Nitrogen Oxides (NOx)

The emissions of nitrogen oxides represent a significant portion of the total emissions generated by this project, and need to be controlled as deemed appropriate. As such, the applicant presented an extensive analysis of the different available technologies for NO_x control.

The applicant stated that BACT for nitrogen oxides will be met by using dry low-NO_x combustor design to limit emissions to 15 ppmvd (corrected to 15% O_2), when burning natural gas; and, by water injection to limit emissions to the applicant's proposed BACT level of up to 54 ppmvd (corrected to 15% O_2), when burning fuel oil.

A review of the EPA's BACT/LAER Clearinghouse indicates that the lowest NO_x emission limit established to date for a combustion turbine is 4.5 ppmvd at 15% oxygen. This level of control was accomplished through the use of water injection and a selective catalytic reduction (SCR) system on two 25 MW combustion turbines located in Kern County, California.

SCR is a post-combustion method for control of NO_x emissions. The SCR process combines vaporized ammonia with NO_x in the presence of a catalyst to form nitrogen and water. The vaporized ammonia is injected into the exhaust gases prior to passage through the catalyst bed. The SCR process can achieve up to 90% reduction of NO_x with a new catalyst. As the catalyst ages, the maximum NO_x reduction efficiency (while holding ammonia slip emissions constant) will decrease.

The effect of exhaust gas temperature on NOx reduction depends on the specific catalyst formulation and reactor design. Generally, SCR units can be designed to achieve effective NOx control over a 100-300°F operating window within the bounds of 450-800°F, although recently developed zeolite-based catalysts are claimed to be capable of operating at temperatures as high as 950°F.

Most commercial SCR systems operate over a temperature range of about 600-750°F. At levels above and below this window, the specific catalyst formulation will not be effective and NO_x reduction will decrease. Operating at high temperatures can permanently damage the catalyst through sintering of surfaces.

Increased water vapor content in the exhaust gas (as would result from water or steam injection in the gas turbine combustor) can shift the operating temperature window of the SCR reactor to slightly higher levels.

The exhaust temperatures of the proposed simple cycle CT for this site will range from 955°F to 1,100°F. At temperatures of 1,100°F and above, the zeolite catalyst (reported to operate to a maximum temperature of 1,050°F) will be irreparably damaged.

Based on the GE data sheets for the proposed DHCT3 provided by the applicant, exhaust temperatures will range from 955°F to 1,100°F, depending upon the fuel fired, ambient temperature and load. Since the zeolite catalysts were reported to operate in this temperature range, ENSERCH Environmental investigated the technical feasibility of using such a system. Because the zeolite catalysts are new, only one vendor (Norton Chemical Process Products Corporation, P.O.

Box 350, Akron, Ohio 44309-0350) was capable of providing a cost estimate. A second vendor was contacted and a cost estimate was requested, but no response was received. This cost estimate noted that the current zeolite catalyst is limited to a maximum upper temperature of 1,050°F and, without an air injection system to cool the exhaust gases at the zeolite catalyst, its use would be infeasible. Review of the GE data sheets for the Deerhaven CT confirmed the vendor's exhaust gas temperature findings. ENSERCH Environmental requested that the vendor revise the initial cost estimate and include the cost of an air injection system.

Based on the information obtained from the vendor, the use of a SCR system equipped with a zeolite catalyst and an air injection system was deemed to be only potentially technically feasible based upon its limited usage on simple cycle CTs. In addition, although the concept of an air injection system is easily visualized, its use commercially has been documented only once in the clearinghouse as a commercially available response to the temperature limitations of SCR. Although only potentially technically feasible, ENSERCH Environmental evaluated the impacts of a SCR system equipped with a high temperature zeolite catalyst and an air injection system as the available post-combustion control technology needed to meet the most stringent emission limitations.

For the simple cycle combustion turbine and based on the information supplied by the applicant, it is estimated that the maximum annual NO_x emissions using a low-NO_x combustor will be 276.42 tons/year. Assuming that SCR would reduce the NO_x emissions by approximately 80%, about 58.22 tons of NO_x would be emitted annually. When this reduction is taken into consideration alone with the total levelized annual operating cost of $1,455,957.33, the incremental cost effectiveness ($/ton) of controlling NO_x is $6,672.58 for this project. These calculated costs are higher than costs previously approved as BACT.

Sulfur Dioxide (SO_2) and Sulfuric Acid Mist (H_2SO_4)

The applicant stated that the sulfur dioxide (SO_2) and sulfuric acid (H_2SO_4) mist emissions, when firing No. 2 fuel oil, will be controlled by using fuel oil with a maximum sulfur content limit of 0.05%, by weight. This will result in an annual emission rate of 81 tons SO_2 per year and 9 tons H_2SO_4 mist per year (with no power augmentation, operating at 1900 hours per year on natural gas, and operating 2000 hours per year on No. 2 fuel oil with a maximum limit of 0.05% sulfur content, by weight).

In accordance with the "top down" BACT review approach, only two alternatives exist that would result in more stringent SO_2 emissions. These include the use of a lower sulfur content fuel oil or the use of wet lime or limestone-based scrubbers, otherwise known as flue gas desulfurization (FGD).

In developing the NSPS for stationary gas turbines, EPA recognized that FGD technology was inappropriate to apply to these combustion units. EPA acknowledged in the preamble of the proposed NSPS that "Due to the high volumes of exhaust gases, the cost of flue gas desulfurization (FGD) to control SO_2 emission from stationary gas turbines is considered unreasonable." EPA reinforced this point when, later in the preamble, they stated that "FGD...would cost about two to three times as much as the gas turbine." The economic impact of applying FGD today is no different.

Furthermore, the application of FGD would have negative environmental and energy impacts. Sludge would be generated that would have to be disposed of properly and there would be increased utility (electricity and water) costs associated with the operation of a FGD system. Finally, there is no information in the literature to indicate that FGD has ever been applied to stationary gas turbines burning distillate oil.

The elimination of flue gas control as a BACT option leaves the use of low sulfur fuel oil as the next option to be investigated. Gainesville Regional Utilities, as stated above, has proposed the use of No. 2 fuel oil with no more than 0.05% sulfur content, by weight, as BACT for this project.

Particulate Matter (PM) Emissions

Particulate matter (PM) emissions from combustion turbines are related to the combustion air, fuel quality and combustion efficiency. Review of the BACT/LAER Clearinghouse indicates that most combustion turbines meet the BACT requirement through filtering the combustion air, good combustion practices, use of clean burning natural gas and limited fuel oil firing. Currently, post combustion controls (i.e., baghouse) are not being used on combustion turbines. This is due mostly to the characteristics of the exhaust gases (high temperatures and velocities) and the low emissions rates for PM when good combustion of low sulfur fuels is employed.

PM_{10} (PM less than 10 microns in diameter) emissions result from noncombustibles in the fuels, PM_{10} in the ambient air used as combustion air, dissolved solids in the water used for wet injection, and incomplete combustion. Since solids can damage the combustion turbine, considerable efforts are made to limit their entry and/or formation. Based on this need and review of the BACT/LAER Clearinghouse data, the applicant proposes prefiltering of the combustion air, good combustion practices, and use of natural gas as the primary fuel and limited annual fuel oil firing as BACT.

BACT Determination by the Department

NO_x Control

The information that the applicant presented and Department calculations indicate that the cost per ton of controlling NO_x for this turbine [$6,672.58 per ton] is high compared with other BACT determinations, which required SCR. Based on the information presented by the applicant, the Department believes that the use of SCR for NO_x control is not justifiable as BACT.

It is the Department's understanding that General Electric is developing controls using either steam/water injection or dry low-NO_x combustor technology to achieve a NO_x emission control level of 9 ppm when firing natural gas. Several prior CT projects have already been permitted at 15 ppmvd @ 15% O_2 (natural gas) and 42 ppmvd @ 15% O_2 (No. 2 fuel oil). In these BACT determinations, no allowance has been made for fuel bound nitrogen or for operation with power augmentation. The Department has determined that BACT for this project is 15 ppmvd @ 15% O_2 using natural gas and 42 ppmvd @ 15% O_2 when firing No. 2 fuel oil. Measured NO_x concentrations shall <u>not</u> be corrected to ISO conditions to determine compliance with these BACT standards. Based on emission rates at the worst case design ambient conditions (20°F) supplied by GE, NO_x emissions will also be limited to 58 lbs/hr for natural gas firing and 184 lbs/hr for fuel oil firing.

SO_2 and H_2SO_4 Mist Control

The Department accepts the applicant's proposal as BACT for sulfur dioxide and H_2SO_4 mist, which is the burning of either natural gas or No. 2 fuel oil with a maximum limit of 0.05% sulfur content, by weight. Fuel oil usage will be limited to no more than 2000 hours per year. GRU has estimated that there is approximately 55 hours of full load operation of fuel oil at 0.25% sulfur content, by weight, remaining in the fuel oil storage tank. GRU will be allowed to deplete this reserve of fuel oil. However, all future deliveries of fuel oil shall meet the BACT requirements, which is a maximum limit of 0.05% sulfur content, by weight.

PM_{10} Control

The Department accepts the applicant's proposed BACT for this emission unit. PM_{10} emissions from fuel burning are related to the sulfur content of the fuel and combustion practices. PM_{10} emissions will be controlled by good combustion practices and firing natural gas; or, firing No. 2 fuel oil for no more than 2000 hours per year. The No. 2 fuel oil shall be limited to no more than 0.05% sulfur content, by weight. In addition, visible emissions shall not exceed 10% opacity when firing natural gas or fuel oil.

BACT Standards

The BACT emission limits for the Gainesville Regional Utilities project, a DHCT3, are established as follows:

MAXIMUM ALLOWABLE EMISSION LIMITS

POLLUTANT	FUEL	BACT STANDARD	LBS/HR *	TPY
NO_x	Gas	15 ppmvd @ 15% Oxygen	58	113(a)
	Oil	42 ppmvd @ 15% Oxygen	184	184(b)
			Combined(c)	239
PM_{10}	Gas	Good combustion; visible emissions shall not exceed 10% opacity	7(d)	14(a)(d)
	Oil	Good combustion of low sulfur oil; visible emissions shall not to exceed 10% opacity	15(d)	15(b)(d)
			Combined(c)	22
SO_2	Gas	Good combustion	29(d)	57(a)(d)
	Oil	Good combustion of low sulfur fuel oil: max. 0.05% sulfur content, by weight	53(d)	53(b)(d)
			Combined(c)	81
	Oil	Good combustion, limited quantity: max. 0.25% sulfur content, by weight		
H_2SO_4 Mist	Gas	Good combustion	3(d)	6(a)(d)
	Oil	Good combustion of low sulfur fuel oil: max. 0.05% sulfur content, by weight	6(d)	6(b)(d)
			Combined(c)	9
	Oil	Good combustion, limited quantity: max. 0.25% sulfur content, by weight		

*These values are calculated using F factors.
(a) Based on a maximum of 3900 hours of operation with natural gas firing.
(b) Based on a maximum of 2000 hours of operation with fuel oil firing.
(c) Based on 1900 hours natural gas firing and 2000 hours of operation with fuel oil firing.
(d) Compliance shall be demonstrated through fuel sulfur analysis.

Monitoring

The BACT emission limitations for NO_x are one-hour averages. Compliance with these standards will be verified by a stack test and excess emissions will be monitored by a stack continuous emissions monitoring system (CEMS) for NO_x and oxygen. The NO_x CEMS will be used in lieu of the water/fuel monitoring system and fuel bound nitrogen (FBN) monitoring which are required in 40 CFR 60, Subpart GG, and which are used as indicators of compliance with the NO_X standard specified in the subpart. Since the NO_X emission standard from Subpart GG is more than twice the BACT standard, monitoring for emissions in excess of the BACT limits using the NO_X CEMS is more stringent. FBN monitoring is not required for excess emission reports when excess emissions are reported based on the stack monitoring system. The calibration of the water/fuel monitoring device required in 40 CFR 60.335(c)(2) will be replaced by certification tests of the NO_X and oxygen CEMS.

Details of the Analysis May be Obtained by Contacting:

Martin Costello, BACT Coordinator, P.E.
Department of Environmental Protection
Bureau of Air Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Recommended by:	Approved by:
_________________________	_________________________
C. H. Fancy, P.E., Chief	Virginia B. Wetherell, Secretary
Bureau of Air Regulation	Dept. of Environmental Protection
____________________, 1995	____________________, 1995
Date	Date

Florida Department of
Environmental Protection

Memorandum

TO : Buck Oven, PPS

FROM: for Clair Fancy JKP

SUBJECT: Gainesville Regional Utilities
PA 74-04/PSD-FL-212

DATE: November 29, 1994

Attached please find a copy of the Conditions of Certification and BACT determination for the GRU Deerhaven Combustion Turbine #3. If you have any questions, please call Bruce Mitchell, Martin Costello or Teresa Heron at (904)488-1344.

Best Available Control Technology (BACT) Determination
Gainesville Regional Utilities
Alachua County

PSD-FL-212

Gainesville Regional Utilities (GRU) proposes to construct a 74 MW (nominal) simple cycle combustion turbine (CT) at the existing Deerhaven site approximately seven miles north of Gainesville in Alachua County. The selected CT, designated as DHCT3, is a GE Model MS 7001 EA with dry low-NO_x combustors and will also use water injection for NO_x control when firing fuel oil.

The applicant requested approval to operate the emission unit for 3900 hours per year, as indicated in the table below. The No. 2 fuel oil will have a maximum limit of 0.05 percent sulfur content, by weight. The applicant has indicated the maximum annual tonnage of regulated air pollutants emitted from the combustion turbine at 100 percent load, at 15% O_2 and ISO conditions (59°F, 60% relative humidity, and 101.3 kilopascals pressure), for each type of fuel fired, to be as follows:

Pollutant	Emissions (TPY) Gas	Gas w/PA *	Oil	Total	PSD Significant Emission Rate (TPY)
	1510 Hrs	390 Hrs	2000 Hrs		
NO_x	40	23	213	276	40
SO_2	20	6	48	74	40
PM/PM_{10}	5	1	15	21	25/15
CO	24	8	65	97	100
VOC	2	1	6	9	40
H_2SO_4 mist	2	1	5	8	7
Be			0.00033	0.00033	0.0004
Hg			0.001	0.001	0.1
Pb			0.0638	0.0638	0.6
As			0	0	0

* with power augmentation

Rule 62-212.400(2)(f)(1), Florida Administrative Code (F.A.C.), requires a BACT review for all regulated pollutants emitted in an amount equal to or greater than the significant emission rates listed in the table above. Therefore, BACT is required for NO_x, SO_2, PM_{10}, and H_2SO_4 mist.

<u>Date of Receipt of a BACT Application</u>

March 25, 1994

BACT Determination Requested by the Applicant

Pollutant	Proposed Limits
NO_x	15 ppmvd @ 15% O_2 (natural gas firing) 54 ppmvd @ 15% O_2 (for No. 2 fuel oil firing) 30 ppmvd @ 15% O_2 (natural gas firing-power augmentation mode). Dry low-NOx combustor when firing natural gas and water injection when firing distillate oil and during power augmentation mode.
PM_{10}	Prefiltering of the combustion air, good combustion practices, and use of natural gas as the primary fuel with limited annual fuel oil firing.
SO_2	0.05% sulfur content by weight (fuel oil firing); also, an equivalent of up to 55 hours of operation at ISO conditions using a fuel oil with a maximum of 0.25% sulfur content, by weight.
H_2SO_4 Mist	0.05% sulfur by weight (fuel oil firing), also, an equivalent of up to 55 hours of operation at ISO conditions using a fuel oil with a maximum of 0.25% sulfur content, by weight.

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:

(a) 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).

(b) All scientific, engineering, and technical material and other information available to the Department.

(c) The emission limiting standards or BACT determination of any other state.

(d) 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 infeasible 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.

The air pollutant emissions from simple cycle combustion turbines can be grouped into categories based upon the control equipment and techniques that are available to control emissions from these emission units. Using this approach, the emissions can be classified as follows:

- Combustion Products (e.g., particulate matter). Controlled generally by good combustion of clean fuels.
- Products of Incomplete Combustion (e.g., carbon monoxide). Control is largely achieved by proper combustion techniques.
- Acid Gases (e.g., nitrogen oxides). Controlled generally by gaseous control devices.

Grouping the pollutants in this manner facilitates the BACT analysis because it enables the equipment available to control the type or group of pollutants emitted and the corresponding energy, economic, and environmental impacts to be examined on a common basis. Although all of the pollutants addressed in the BACT analysis may be subject to a specific emission limiting standard as a result of PSD review, the control of "nonregulated" air pollutants is considered in imposing a more stringent BACT limit on a "regulated" pollutant (i.e., particulate matter, sulfur dioxide, fluorides, sulfuric acid mist, etc,), if a reduction in "nonregulated" air pollutants can be directly attributed to the control device selected as BACT for the abatement of the "regulated" pollutants.

<u>ACID GASES</u>

Nitrogen Oxides (NOx)

The emissions of nitrogen oxides represent a significant portion of the total emissions generated by this project, and need to be controlled as deemed appropriate. As such, the applicant presented an extensive analysis of the different available technologies for NO_x control.

The applicant stated that BACT for nitrogen oxides will be met by using dry low-NO_x combustor design to limit emissions to 15 ppmvd (corrected to 15% O_2), when burning natural gas; and, by water injection to limit emissions to the applicant's proposed BACT level of 54 ppmvd (corrected to 15% O_2), when burning fuel oil.

A review of the EPA's BACT/LAER Clearinghouse indicates that the lowest NO_x emission limit established to date for a combustion turbine is 4.5 ppmvd at 15% oxygen. This level of control was accomplished through the use of water injection and a selective catalytic reduction (SCR) system on two 25 MW combustion turbines located in Kern County, California.

SCR is a post-combustion method for control of NO_x emissions. The SCR process combines vaporized ammonia with NO_x in the presence of a catalyst to form nitrogen and water. The vaporized ammonia is injected into the exhaust gases prior to passage through the catalyst bed. The SCR process can achieve up to 90% reduction of NO_x with a new catalyst. As the catalyst ages, the maximum NO_x reduction efficiency (while holding ammonia slip emissions constant) will decrease.

The effect of exhaust gas temperature on NOx reduction depends on the specific catalyst formulation and reactor design. Generally, SCR units can be designed to achieve effective NOx control over a 100-300°F operating window within the bounds of 450-800°F, although recently developed zeolite-based catalysts are claimed to be capable of operating at temperatures as high as 950°F.

Most commercial SCR systems operate over a temperature range of about 600-750°F. At levels above and below this window, the specific catalyst formulation will not be effective and NO_x reduction will decrease. Operating at high temperatures can permanently damage the catalyst through sintering of surfaces.

Increased water vapor content in the exhaust gas (as would result from water or steam injection in the gas turbine combustor) can shift the operating temperature window of the SCR reactor to slightly higher levels.

The exhaust temperatures of the proposed simple cycle CT for this site will range from 955°F to 1,100°F. At temperatures of 1,100°F and above, the zeolite catalyst (reported to operate to a maximum temperature of 1,050°F) will be irreparably damaged.

Based on the GE data sheets for the proposed DHCT3 provided by the applicant, exhaust temperatures will range from 955°F to 1,100°F, depending upon the fuel fired, ambient temperature and load. Since the zeolite catalysts were reported to operate in this temperature range, ENSERCH Environmental investigated the technical feasibility of using such a system. Because the zeolite catalysts are new, only one vendor (Norton Chemical Process Products Corporation, P.O.

Box 350, Akron, Ohio 44309-0350) was capable of providing a cost estimate. A second vendor was contacted and a cost estimate was requested, but no response was received. This cost estimate noted that the current zeolite catalyst is limited to a maximum upper temperature of 1,050°F and, without an air injection system to cool the exhaust gases at the zeolite catalyst, its use would be infeasible. Review of the GE data sheets for the Deerhaven CT confirmed the vendor's exhaust gas temperature findings. ENSERCH Environmental requested that the vendor revise the initial cost estimate and include the cost of an air injection system.

Based on the information obtained from the vendor, the use of a SCR system equipped with a zeolite catalyst and an air injection system was deemed to be only potentially technically feasible based upon its limited usage on simple cycle CTs. In addition, although the concept of an air injection system is easily visualized, its use commercially has been documented only once in the clearinghouse as a commercially available response to the temperature limitations of SCR. Although only potentially technically feasible, ENSERCH Environmental evaluated the impacts of a SCR system equipped with a high temperature zeolite catalyst and an air injection system as the available post-combustion control technology needed to meet the most stringent emission limitations.

For the simple cycle combustion turbine and based on the information supplied by the applicant, it is estimated that the maximum annual NO_x emissions using a low-NO_x combustor will be 276.42 tons/year. Assuming that SCR would reduce the NO_x emissions by approximately 80%, about 58.22 tons of NO_x would be emitted annually. When this reduction is taken into consideration alone with the total levelized annual operating cost of $1,455,957.33, the incremental cost effectiveness ($/ton) of controlling NO_x is $6,672.58 for this project. These calculated costs are higher than costs previously approved as BACT.

Sulfur Dioxide (SO_2) and Sulfuric Acid Mist (H_2SO_4)

The applicant stated that the sulfur dioxide (SO_2) and sulfuric acid (H_2SO_4) mist emissions, when firing No. 2 fuel oil, will be controlled by using fuel oil with a maximum sulfur content limit of 0.05%, by weight. This will result in an annual emission rate of 67 tons SO_2 per year and 7.2 tons H_2SO_4 mist per year (with no power augmentation, operating at 1900 hours per year on natural gas, and operating 2000 hours per year on No. 2 fuel oil with a maximum limit of 0.05% sulfur content, by weight).

In accordance with the "top down" BACT review approach, only two alternatives exist that would result in more stringent SO_2 emissions. These include the use of a lower sulfur content fuel oil or the use of wet lime or limestone-based scrubbers, otherwise known as flue gas desulfurization (FGD).

In developing the NSPS for stationary gas turbines, EPA recognized that FGD technology was inappropriate to apply to these combustion units. EPA acknowledged in the preamble of the proposed NSPS that "Due to the high volumes of exhaust gases, the cost of flue gas desulfurization (FGD) to control SO_2 emission from stationary gas turbines is considered unreasonable." EPA reinforced this point when, later in the preamble, they stated that "FGD...would cost about two to three times as much as the gas turbine." The economic impact of applying FGD today is no different.

Furthermore, the application of FGD would have negative environmental and energy impacts. Sludge would be generated that would have to be disposed of properly and there would be increased utility (electricity and water) costs associated with the operation of a FGD system. Finally, there is no information in the literature to indicate that FGD has ever been applied to stationary gas turbines burning distillate oil.

The elimination of flue gas control as a BACT option leaves the use of low sulfur fuel oil as the next option to be investigated. Gainesville Regional Utilities, as stated above, has proposed the use of No. 2 fuel oil with no more than 0.05% sulfur content, by weight, as BACT for this project.

Particulate Matter (PM) Emissions

Particulate matter (PM) emissions from combustion turbines are related to the combustion air, fuel quality and combustion efficiency. Review of the BACT/LAER Clearinghouse indicates that most combustion turbines meet the BACT requirement through filtering the combustion air, good combustion practices, use of clean burning natural gas and limited fuel oil firing. Currently, post combustion controls (i.e., baghouse) are not being used on combustion turbines. This is due mostly to the characteristics of the exhaust gases (high temperatures and velocities) and the low emissions rates for PM when good combustion of low sulfur fuels is employed.

PM_{10} (PM less than 10 microns in diameter) emissions result from noncombustibles in the fuels, PM_{10} in the ambient air used as combustion air, dissolved solids in the water used for wet injection, and incomplete combustion. Since solids can damage the combustion turbine, considerable efforts are made to limit their entry and/or formation. Based on this need and review of the BACT/LAER Clearinghouse data, the applicant proposes prefiltering of the combustion air, good combustion practices, and use of natural gas as the primary fuel and limited annual fuel oil firing as BACT.

BACT Determination by the Department

NO_x Control

The information that the applicant presented and Department calculations indicate that the cost per ton of controlling NO_x for this turbine [$6,672.58 per ton] is high compared with other BACT determinations, which required SCR. Based on the information presented by the applicant, the Department believes that the use of SCR for NO_x control is not justifiable as BACT.

It is the Department's understanding that General Electric is developing controls using either steam/water injection or dry low-NO_x combustor technology to achieve a NO_x emission control level of 9 ppm when firing natural gas. Several prior CT projects have already been permitted at 15 ppmvd @ 15% O_2 (natural gas) and 42 ppmvd @ 15% O_2 (No. 2 fuel oil). In these BACT determinations, no allowance has been made for fuel bound nitrogen or for operation with power augmentation. The Department has determined that BACT for this project is 15 ppmvd @ 15% O_2 using natural gas and 42 ppmvd @ 15% O_2 when firing No. 2 fuel oil. Measured NO_x concentrations shall <u>not</u> be corrected to ISO conditions to determine compliance with these BACT standards. Based on emission rates at the worst case design ambient conditions (20°F) supplied by GE, NO_x emissions will also be limited to 58 lbs/hr for natural gas firing and 184 lbs/hr for fuel oil firing.

SO_2 and H_2SO_4 Mist Control

The Department accepts the applicant's proposal as BACT for sulfur dioxide and H_2SO_4 mist, which is the burning of either natural gas or No. 2 fuel oil with a maximum limit of 0.05% sulfur content, by weight. Fuel oil usage will be limited to no more than 2000 hours per year. GRU has estimated that there is approximately 55 hours of full load operation of fuel oil at 0.25% sulfur content, by weight, remaining in the fuel oil storage tank. GRU will be allowed to deplete this reserve of fuel oil. However, all future deliveries of fuel oil shall meet the BACT requirements, which is a maximum limit of 0.05% sulfur content, by weight.

PM_{10} Control

The Department accepts the applicant's proposed BACT for this emission unit. PM_{10} emissions from fuel burning are related to the sulfur content of the fuel and combustion practices. PM_{10} emissions will be controlled by good combustion practices and firing natural gas; or, firing No. 2 fuel oil for no more than 2000 hours per year. The No. 2 fuel oil shall be limited to no more than 0.05% sulfur content, by weight. In addition, visible emissions shall not exceed 10% opacity when firing natural gas or fuel oil.

BACT Standards

The BACT emission limits for the Gainesville Regional Utilities project, a DHCT3, are established as follows:

MAXIMUM ALLOWABLE EMISSION LIMITS

POLLUTANT	FUEL	BACT STANDARD	LBS/HR *	TPY
NO_x	Gas	15 ppmvd @ 15% Oxygen	58	55
	Oil	42 ppmvd @ 15% Oxygen	184	184
PM_{10}	Gas	Good combustion; visible emissions shall not exceed 10% opacity	7 **	7 **
	Oil	Good combustion of low sulfur oil; visible emissions shall not exceed 10% opacity	15 **	15 **
SO_2	Gas	Good combustion	29 **	26 **
	Oil	Good combustion of low sulfur fuel oil: max. 0.05% sulfur content, by weight	53 **	53 **
	Oil	Good combustion, limited quantity: max. 0.25% sulfur content, by weight		
H_2SO_4 Mist	Gas	Good combustion	3 **	3 **
	Oil	Good combustion of low sulfur fuel oil: max. 0.05% sulfur content, by weight	6 **	6 **
	Oil	Good combustion, limited quantity: max. 0.25% sulfur content, by weight		

* These values are calculated using F-factors.
** Compliance shall be demonstrated through fuel sulfur analysis.

Monitoring

The BACT emission limitations for NO_x are one-hour averages. Compliance with these standards will be verified by a stack test and excess emissions will be monitored by a stack continuous emissions monitoring system (CEMS) for NO_x and oxygen. The NO_x CEMS will be used in lieu of the water/fuel monitoring system and fuel bound nitrogen (FBN) monitoring which are required in 40 CFR 60, Subpart GG, and which are used as indicators of compliance with the NO_X standard specified in the subpart. Since the NO_X emission standard from Subpart GG is more than twice the BACT standard, monitoring for emissions in excess of the BACT limits using the NO_X CEMS is more stringent. FBN levels are not required for excess emission reports when excess emissions are reported based on the stack monitoring system. The calibration of the water/fuel monitoring device required in 40 CFR 60.335(c)(2) will be replaced by certification tests of the NO_X CEMS.

<u>Details of the Analysis May be Obtained by Contacting</u>:

Martin Costello, BACT Coordinator, P.E.
Department of Environmental Protection
Bureau of Air Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Recommended by:	Approved by:
____________________________	________________________________
C. H. Fancy, P.E., Chief Bureau of Air Regulation	Virginia B. Wetherell, Secretary Dept. of Environmental Protection
______________________, 1994 Date	_________________________, 1994 Date

GAINESVILLE REGIONAL UTILITIES
Conditions of Certification
PA 74-04 and PSD-FL-212

AIR

The construction and operation of the Gainesville Regional Utilities (GRU) Deerhaven Combustion Turbine #3 (DHCT3) shall be in accordance with all applicable provisions of Chapters 62-210 through 297 and 62-4, Florida Administrative Code (F.A.C.), and 40 CFR 60, Subpart A, Subpart GG, Appendix A and Appendix B (1993 version). The following emission limitations and conditions reflect the BACT determinations for the DHCT3. In addition to the foregoing, the project shall comply with the following conditions of certification:

General Operating Requirements

1. The maximum heat input rates, based on high heating values of each fuel, to the DHCT3 and at ISO conditions (i.e., 59° F, 60% relative humidity and 101.3 kilopascals pressure), shall not exceed 971.1 MMBTU/hr, while firing natural gas, nor 990.6 MMBTU/hr, while firing fuel oil. Heat input will vary depending on ambient conditions and the DHCT3 characteristics. Manufacturer's curves or equations for correction to other ambient conditions shall be provided to the Department of Environmental Protection (DEP) at least 90 days before initial compliance testing.

2. The DHCT3 is allowed to operate up to 3900 hours per year, but not to exceed 2000 hours while firing fuel oil.

3. Only natural gas (NG) or No. 2 fuel oil shall be fired in the combustion turbine. The maximum sulfur content of the fuel oil shall not exceed 0.05 percent, by weight. GRU has established that there is approximately 55 hours of full load operation of fuel oil, which contains nominally 0.25% sulfur content, by weight, remaining in the fuel storage tank. GRU will be allowed to deplete this reserve by firing the fuel oil in the DHCT3. However, all future deliveries of fuel oil for the DHCT3 shall meet the BACT requirement, which limits the fuel oil sulfur content to no more than 0.05%, by weight. Fuel sulfur content shall be determined and recorded each time fuel is transferred into the bulk storage tank(s).

4. 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 pursuant to Rule 62-296.310(3), F.A.C. - Unconfined Emissions of Particulate Matter.

5. Any change in the method of operation, equipment or operating hours, pursuant to Rule 62-212.200, F.A.C., Definitions-Modifications, shall be submitted to the DEP's Bureau of Air Regulation office and Northeast District office.

Emission Limits

6. The maximum allowable emissions from the DHCT3, when firing natural gas or No. 2 fuel oil, in accordance with the BACT determination, and at 95 - 100% percent load based on the manufacturer's curves submitted to the DEP, shall not exceed the following limits except during periods of start up, shutdown, and malfunction pursuant to Rule 62-210.700, F.A.C.:

MAXIMUM ALLOWABLE EMISSION LIMITS

POLLUTANT	FUEL	BACT STANDARD	LBS/HR *	TPY
NO_x	Gas	15 ppmvd @ 15% Oxygen	58	55
	Oil	42 ppmvd @ 15% Oxygen	184	184
PM_{10}	Gas	Good combustion; visible emissions shall not exceed 10% opacity	7 **	7 **
	Oil	Good combustion of low sulfur oil; visible emissions shall not exceed 10% opacity	15 **	15 **
SO_2	Gas	Good combustion	29 **	28 **
	Oil	Good combustion of low sulfur fuel oil: max. 0.05% sulfur content, by weight	53 **	53 **
	Oil	Good combustion, limited quantity: max. 0.25% sulfur content, by weight		
H_2SO_4 Mist	Gas	Good combustion	3 **	3 **
	Oil	Good combustion of low sulfur fuel oil: max. 0.05% sulfur content, by weight	6 **	6 **
	Oil	Good combustion, limited quantity: max. 0.25% sulfur content, by weight		

* These values are calculated using F-factors.
** Compliance shall be demonstrated through fuel sulfur analysis.

7. Visible emissions shall not exceed 10% opacity when firing natural gas or No. 2 fuel oil.

8. The potential emissions projected from the DHCT3 are:

ESTIMATED POTENTIAL EMISSIONS

Pollutant	Method of Control	TPY **
CO	Good combustion, proper use of water injection system	95.4
VOC	Good combustion	8.9
Inorganic Arsenic	Natural Gas/No. 2 Fuel Oil	0
Mercury	Natural Gas/No. 2 Fuel Oil	0.001
Pb	Natural Gas/No. 2 Fuel Oil	0.0638
Be	Natural Gas/No. 2 Fuel Oil	0.00033

** TPY values are for annual operation reports (AOR) and PSD applicability determinations. These values are based on the DHCT3 operating at full load at ISO for a total of 3900 hours per year, with up to 2000 hours of No. 2 fuel oil-fired operation.

Compliance Determination

9. Compliance with the allowable emission limiting standards shall be determined within 60 days after achieving the maximum production rate at which this unit will be operated, but not later than 180 days of initial operation at the maximum capability of the unit and annually thereafter, by using the following reference methods as described in 40 CFR 60, Appendix A (1993 version), and adopted by reference in Chapter 62-297, F.A.C.

Initial (I) compliance tests shall be performed on the DHCT3 while firing each fuel (gas, oil). Annual (A) compliance tests shall be performed during every federal fiscal year (October 1 - September 30) pursuant to Rule 62-297.340, F.A.C., on the DHCT3 with the fuel(s) used for more than 400 hours in the preceding 12-month period.

- Method 9 — Visual Determination of the Opacity of Emissions from Stationary Sources (I,A)

- Method 10 Determination of Carbon Monoxide Emissions from Stationary Sources (I)

- Method 20 Determination of Nitrogen Oxides and Diluent Emissions from Stationary Gas Turbines (I,A)

Note: No other methods may be used for compliance testing unless prior DEP approval is received in writing. The DEP may request a special compliance test pursuant to Rule 62-297.340(2), F.A.C., when, after investigation (such as complaints, increased visible emissions, or questionable maintenance of control equipment), there is reason to believe that any applicable emission standard is being violated.

10. Notwithstanding the requirements of Rule 62-297.340, F.A.C., the exclusive use of fuel oil with a maximum sulfur content limit of 0.05% or less, by weight, is the method for determining compliance for SO_2, H_2SO_4 mist, and PM_{10}. There is no suitable method for the testing of PM_{10} from this type of emissions unit, and the SO_2 and H_2SO_4 emissions are clearly limited by the sulfur content of the fuel. Compliance with the SO_2 and sulfuric acid mist emission limits shall be determined by fuel oil analysis using ASTM D2880-71 or D4294 (or equivalent) for the sulfur content of liquid fuels and D1072-80, D3031-81, D4084-82 or D3246-81 (or equivalent) for sulfur content of gaseous fuel. Alternatively, natural gas supplier data for sulfur content may be submitted. However, the applicant is responsible for ensuring that the procedures above are used for determination of fuel sulfur content. 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 pursuant to 40 CFR 60.335(e) (1993 version).

11. Pursuant to Rule 62-212.410, F.A.C., the permittee shall install a dry low-NO_x combustor on the DHCT3 for NO_x control when firing natural gas. Control of NO_x when firing No. 2 fuel oil shall be accomplished by water injection.

12. An initial test for CO, concurrent with each NO_x test, is required to confirm that annual potential emissions will not exceed 100 TPY. The NOx and initial CO test results shall be the average of three valid one-hour runs. The DEP's Northeast District office shall be notified, in writing, at least 30 days prior to the initial compliance tests and at least 15 days before annual compliance test(s). The combustion turbine shall operate between 95% and 100% of maximum capacity for the ambient conditions experienced during compliance test(s). The turbine manufacturer's

heat input rates (based on the high heating value of the fuel) vs. ambient temperature curve shall be included with the compliance test results. The fuel feed rates and the high heating value of the fuels shall be established during the initial and annual compliance tests. Compliance test results shall be submitted to the DEP's Northeast District office no later than 45 days after completion of the last test run.

13. Excess NO_x emissions from this turbine resulting from startup, shutdown, malfunction, fuel switching or load change, shall be acceptable providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24-hour period unless specifically authorized by the DEP's Bureau of Air Regulation or the Northeast District office for a longer duration. Best operating practices shall be documented in writing and a copy submitted to the DEP's Northeast District office along with the initial compliance test data. The document may be updated as needed with all updates submitted to the DEP's Northeast District office within thirty (30) days of implementation and shall include time limitations on excess emissions caused by turbine startup.

Notification, Reporting and Recordkeeping

14. Notification and recordkeeping shall be in accordance with 40 CFR 60.7 (1993 version). The following protocols shall be submitted to the DEP's Northeast District office for approval:

a. CEMS - If applicable, the Federal Acid Rain Program requirements of 40 CFR 75 shall apply when those requirements become effective in Florida.

b. Performance Test Protocol - At least 30 days prior to conducting the initial performance tests required by this permit, the permittee shall submit to the DEP's Northeast District office for their review and approval: a protocol outlining the procedures to be followed; the test methods; and, any differences between the reference methods and the test methods proposed to be used to verify compliance with the conditions of this permit.

c. All measurements, records, and other data required to be maintained by GRU shall be retained for at least five (5) years following the date on which such measurements, records, or data are recorded. These data shall be made available to the DEP representatives.

Monitoring Requirements

15. The permittee shall install, calibrate, maintain, and operate a continuous emission monitor in the stack to measure and record the nitrogen oxides emissions from this source. One-hour periods when NO_x emissions (ppmvd @ 15% oxygen) are above the BACT standards (15/42 gas/oil) shall be reported as excess emissions following the

format of 40 CFR 60.7 (1993 version). The continuous emission monitor must comply with Rule 62-297.500, F.A.C.; 40 CFR 60, Appendix F, Quality Assurance Procedures (1993 version) (or other DEP approved QA plan); 40 CFR 60, Appendix B, Performance Specification 2 (1993 version); or, if applicable, 40 CFR 75, Appendix A and Appendix B. Periods of startup, shutdown, fuel switching, malfunction, and load change shall be monitored and recorded. The NO_X CEMS will be used in lieu of the water/fuel monitoring system and fuel bound nitrogen (FBN) monitoring, which are required in accordance with 40 CFR 60, Subpart GG (1993 version), and are used as indicators of compliance with the NO_X standard specified in the subpart. Since the NO_X emission standard from Subpart GG is more than twice the BACT standard, monitoring for emissions in excess of the BACT limits using the NO_X CEMS is more stringent. FBN levels are not required for excess emission reports when excess emissions are reported and based on the stack monitoring system. The calibration of the water/fuel monitoring device required in 40 CFR 60.335(c)(2) (1993 version) will be replaced by certification tests of the NO_X CEMS.

16. A malfunction means any sudden and unavoidable failure of air pollution control equipment or process equipment to operate in a normal or usual manner. Failures that are caused entirely or in part by poor maintenance, careless operation, or any other preventable upset condition or preventable equipment breakdown shall not be considered malfunctions and shall be prohibited pursuant to Rule 62-210.700, F.A.C.

17. The sulfur content of the fuel oil being fired in the combustion turbine shall be determined in accordance with 40 CFR 60.334(b) (1993 version). Any request for a future custom monitoring schedule shall be made in writing and directed to the DEP's Bureau of Air Regulation office. Any custom schedule approved by the DEP pursuant to 40 CFR 60.334(b) (1993 version) will be recognized as enforceable provisions of the permit, provided that the holder of this permit demonstrates that the provisions of the schedule will be adequate to assure continuous compliance. The records of natural gas and No. 2 fuel oil usage shall be kept by the company for a five-year period for regulatory agency inspection purposes.

<u>Rule Requirements</u>

18. The emission unit shall be in compliance with all applicable provisions of Chapter 403, Florida Statutes, and Chapters 62-4, 210, 212, 275, 296 and 297, F.A.C.

19. The emission unit shall be in compliance with all applicable requirements of 40 CFR 60, Subpart A, Appendix A and Appendix B (1993 version), Subpart GG - Standards of Performance for

Stationary Gas Turbines (1993 version), and Rule 62-296.800(2)(a), 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). All notifications and reports required by this specific condition shall be submitted to the DEP's Northeast District office.

20. Issuance of this permit does not relieve the facility owner or operator from compliance with any applicable federal, state, or local permitting requirements and regulations (Rule 62-210.300(1), F.A.C.).

21. The emission unit shall be in compliance with all applicable provisions of Rule 62-210.650, F.A.C.: Circumvention; Rule 62-210.700, F.A.C.: Excess Emissions; Rule 62-296.800, F.A.C.: Standards of Performance for New Stationary Sources (NSPS); Chapter 62-297, F.A.C.: Stationary Sources - Emissions Monitoring; and, Rule 62-4.130, F.A.C.: Plant Operation - Problems.

22. If construction does not commence within 18 months of issuance of this permit, the permittee shall obtain from the DEP's Bureau of Air Regulation a review and, if necessary, a modification of the BACT determination and allowable emissions for the unit(s) on which construction has not commenced (40 CFR 52.21(r)(2) (1993 version)).

23. Quarterly excess emission reports, in accordance with 40 CFR 60.7 and 60.334 (1993 version), shall be submitted to the DEP's Northeast District office.

24. Pursuant to Rule 62-210.370(2), F.A.C., Annual Operating Reports, the permittee is required to submit annual reports on the actual operating rates and emissions from this facility. These reports shall include, but are not limited to the following: sulfur content of the fuel being fired, fuel usage, hours of operation, air emissions limits, etc. Annual operating reports shall be sent to the DEP's Northeast District office by March 1st of each calendar year.

25. Stack sampling facilities shall be installed in accordance with Rule 62-297.345, F.A.C.

Modifications

26. The permittee shall give written notification to the DEP when there is any modification to this facility/emission unit pursuant to Rule 62-212.200, F.A.C., Definitions - Modifications. This notice shall be submitted sufficiently in advance of any critical date involved to allow sufficient time for review, discussion, and revision of the application/request, if necessary. Such notice shall include, but not be limited to: information describing the precise nature of the change; modification(s) to any emission control system; production capacity of the facility/emissions unit before and after the change; and, the anticipated completion date of the change.