Department of Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

February 21, 1995

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. William C. Walbridge
Executive Vice President
Seminole Electric Cooperative Incorporated
P. O. Box 272000
Tampa, Florida 33688-2000

Dear Mr. Walbridge:

Attached is a copy of the Technical Evaluation and Preliminary Determination, proposed permit and the Best Available Control Technology evaluation to construct a 440 MW combined cycle power plant consisting of two gas turbine generators, associated heat recovery steam generators and a single steam turbine-generator.

Submit any written comments for consideration concerning the Department's proposed action to Mr. A. A. Linero of the Bureau of Air Regulation. If there any questions, please call Mr. Syed Arif at (904)488-1344.

Sincerely,

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

CHF/SA/bjb

Attachments

cc: B. Thomas, SWD
S. Palmer, DEP
J. Harper, EPA
J. Bunyak, NPS
L. Novak, Polk County
D. Roberts, HBGS
K. Kosky, P.E., KBN

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PS Form 3800, March 1993

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Executive V.P.
Seminole Electric Coop Inc
P.O. Box 272000
Tampa, Fl 33688-2000

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STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

CERTIFIED MAIL

In the Matter of an
Application for Permit by:

DEP File No. PSD-FL-214
(PA-89-25SA)
Hardee and Polk Counties

Seminole Electric Cooperative Incorporated
P. O. Box 272000
Tampa, FL 33688-2000
/

INTENT TO ISSUE

The Department of Environmental Protection (Department) hereby gives notice of its intent to issue a PSD 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, Seminole Electric Cooperative Incorporated, applied on May 9, 1994, to the Department of Environmental Protection for a permit to construct a 440 MW combined cycle power plant consisting of two gas turbine generators, associated heat recovery steam generators, and a single steam turbine-generator. The proposed facility will be located near Bowling Green, Hardee 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
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 2/21/95 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 — 2/21/95
Clerk — Date

Copies furnished to:

cc: B. Thomas, SWD
S. Palmer, DEP
J. Harper, EPA
J. Bunyak, NPS
L. Novak, Polk County
D. Roberts, HBGS
K. Kosky, P.E., KBN

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

PSD-FL-214
(PA-89-25SA)

The Department of Environmental Protection (Department) gives notice of its intent to issue a permit to Seminole Electric Cooperative Incorporated, P. O. Box 272000, Tampa, FL 33688, to construct a 440 MW combined cycle power plant consisting of two gas turbine generators, associated heat recovery steam generators, and a single steam turbine-generator. The proposed facility will be located in Hardee and Polk Counties, Florida. A determination of Best Available Control Technology was required. The maximum predicted increase in nitrogen dioxide concentrations due to the project are less than the respective PSD Class I and II significant impact levels, thus no nitrogen dioxide PSD increment consumption was calculated for this project. The maximum predicted increases in particulate matter less than 10 microns (PM_{10}) concentrations due to the project are less than the respective PSD Class I significant impact levels, thus no PSD Class I PM_{10} increment consumption was calculated for this project. The maximum predicted PSD Class II PM_{10} increments to be consumed by the proposed project are the following: 21.5 ug/m^3, 24-hour average, or 72% of the available 24-hour increment of 30 ug/m^3; and, 0.12 ug/m^3, annual average, or less than one percent of the available annual increment of 17 ug/m^3. The maximum predicted PSD Class II sulfur dioxide increments to be consumed by the proposed project are the following: 65.1 ug/m^3, 3-hour average, or 13% of the available 3-hour increment of 512 ug/m^3; 27.8 ug/m^3, 24-hour average, or 31% of the available 24-hour increment of 91 ug/m^3; and, 0.18 ug/m^3, annual average, or less than one percent of the available increment of 20 ug/m^3. The maximum predicted PSD Class I sulfur dioxide increments to be consumed by the proposed project are the following: 1.9 ug/m^3, 3-hour average, or 8% of the available 3-hour increment of 25 ug/m^3; 0.3 ug/m^3, 24-hour average, or 6% of the available 24-hour increment of 5 ug/m^3; and, 0.012 ug/m^3, annual average, or less than one percent of the available annual increment of 2 ug/m^3. 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
Southwest District
3804 Coconut Palm Drive
Tampa, Florida 33619-8218

Any person may send written comments on the proposed action to Mr. A. A. Linero at the Department of Environmental Protection, Bureau of Air Regulation, Mail Station 5505, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400. All comments received within 14 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

Seminole Electric Cooperative Incorporated
Hardee & Polk Counties, Florida

440 MW COMBINED CYCLE POWER PLANT

Department File No.: PSD-FL-214
(PA-89-25SA)

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

February 21, 1995

SYNOPSIS OF APPLICATION

I. GENERAL INFORMATION

A. Name and Address of Applicant

Seminole Electric Cooperative Incorporated
P. O. Box 272000
Tampa, FL 33688-2000

B. Reviewing and Process Schedule

Date of Receipt of Application: May 9, 1994.

Completeness Review: Department letters dated June 27, 1994; September 21, 1994; and, November 16, 1994.

Response to Incompleteness Letters: Company letters received on August 26, 1994; October 6, 1994; and, November 23, 1994.

Application Completeness Date: November 23, 1994.

C. Facility Location

This facility is located in Hardee and Polk Counties approximately 9 miles northwest of Wauchula and 16 miles south-southwest of Bartow. The UTM coordinates are Zone 17, 405.0 km East and 3057.7 km North.

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.

D. Project Description

The Seminole Electric Cooperative Incorporated (SECI) facility in Polk and Hardee Counties is classified as a major emitting facility. The proposed project consists of the construction of two gas combustion turbine (CT) generators, associated heat recovery steam generators (HRSGs), and a single steam turbine-generator at a facility adjacent to the Hardee Power Station's existing units located in Hardee and Polk Counties. The facility, referred to as Hardee Unit 3, will consist of two 150 megawatt (MW) Westinghouse Model 501F, or equivalent, advanced CTs. Each CT will be connected to a separate HRSG, which will recover the waste heat to produce steam for utilization in a single 140 MW (net) steam turbine. The facility will have a total nominal generating capacity of 440 MW (net). The primary fuel for the CTs will be natural gas, with distillate (No. 2) fuel oil containing a maximum sulfur content of 0.05 percent, by weight, designated as the backup fuel.

E. Project Emissions

The proposed project will produce potential pollutant emissions of 1139 tons per year (TPY) of nitrogen oxides (NO_x); 175 TPY of sulfur dioxide (SO_2); 614 TPY of carbon monoxide (CO); 145 TPY of particulate matter (PM/PM_{10}); 99 TPY of volatile organic compounds (VOC); 0.007 TPY of beryllium (Be); 0.16 TPY of lead (Pb); 0.014 TPY inorganic arsenic (As); 0.025 TPY of mercury (Hg); and, 38 TPY of sulfuric acid (H_2SO_4) mist. This assumes if operation at 8760 hours per year (7,260 hours per year on natural gas and a maximum of 3,000 hours per year between the two CTs on No. 2 fuel oil using a maximum of 0.05 percent sulfur, by weight).

II. RULE APPLICABILITY

The proposed project, construction of a 440 MW combined cycle power plant (SIC 4911) in Polk & Hardee Counties, is subject to the State Power Plant Siting Act (PPSA) and preconstruction review under the provisions of Chapter 403, Florida Statutes, Chapters 62-212 and 62-4, Florida Administrative Code (F.A.C.), and 40 CFR 60 (July 1, 1994 version).

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 project was reviewed under Rule 62-212.400(5), F.A.C., New Source Review (NSR) for Prevention of Significant Deterioration (PSD), because it will be a major modification to a major facility. This review consisted of a determination of Best Available Control Technology (BACT) and, unless otherwise exempted, an analysis of the air quality impact of the increased emissions. The review also includes an analysis of the project's impacts on soils, vegetation and visibility, along with air quality impacts resulting from associated commercial, residential and industrial growth.

The proposed facility shall be in compliance with all applicable provisions of Chapters 62-212 and 62-4, F.A.C., and the 40 CFR 60 (July 1, 1994 version). The proposed facility shall be in compliance with all applicable provisions of Rules 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 62-296, F.A.C.: Stationary Sources - Emissions Monitoring; and, Rule 62-4.130, F.A.C.: Plant Operation-Problems.

The proposed facility shall be in compliance with the New Source Performance Standards (NSPS) for Gas Turbines, Subpart GG, and for volatile organic storage vessels, Subpart Kb, which are contained in 40 CFR 60 and adopted by reference in Rule 62-296.800, F.A.C.

III. TECHNICAL EVALUATION

The applicant proposes to install a 440 MW combined cycle power plant at its facility in Polk and Hardee Counties. The plant will consist of two nominal 150 megawatt (MW) Westinghouse Model 501F, or equivalent CTs that will exhaust through two associated unfired HRSGs, which will supply steam to power a single 140 MW (net) steam turbine generator. The proposed facility will include a 4.4 million gallon fuel oil storage tank. The proposed facility will be capable of producing a nominal 440 MW of electricity.

In 1990, the Hardee Power Station was certified for 660 MW of generation in a phased construction schedule as follows:

1. TECO Power Services - 295 MW (1993) (Phase 1A).
2. TECO Power Services - 145 MW (future unit) (Phase 1B).
3. SECI - 220 MW (date unspecified) (Phase 2).

This new certification does not change Phases 1A and 1B, above, but will increase the SECI certified generation (Phase 2) from 220 MW to 440 MW, with an inservice date of January, 1999. Because of the phased construction activity, the Department looked at the total emissions for the Phase 2 project to see if any additional pollutants (i.e., Hg, Pb, etc.) should be reviewed from the BACT determination process.

The primary fuel to the two CTs will be natural gas. No. 2 fuel oil with a maximum sulfur content of 0.05%, by weight, will be used as a backup fuel for a maximum of 3,000 hours per year between the two CTs. The CTs will be firing natural gas for the remaining hours of operation. The emissions of nitrogen oxides (NO_X) represent a significant proportion of the total emissions generated by this project. The BACT for NO_X, as determined by the Department, will be met by using low-NO_X combustors to limit emissions to 15 ppmvd (corrected to 15% O_2) when burning natural gas and water injection to limit emissions to 42 ppmvd (corrected to 15% O_2) when burning fuel oil. The facility is subject to PSD new source review (NSR) and BACT for NO_x emissions because the proposed increase in annual NO_x emissions exceeds the significant emission rate. Compliance with the emission standards will be determined by stack tests.

Particulate matter (PM/PM_{10}) emissions from the combined cycle combustion turbines will be minimized by combustion control and the use of clean fuels. The Department agrees with the applicant's rationale that there are no feasible methods to control lead, mercury, beryllium and other trace pollutants, except by requiring good quality fuel. The facility is subject to PSD NSR and BACT for PM/PM_{10} emissions because the proposed increase in annual PM/PM_{10} emissions exceeds the significant emission rate. Compliance will be determined by periodic stack tests.

SO_2 and H_2SO_4 mist emissions will be controlled by the use of low sulfur fuel oil. The No. 2 fuel oil, which will be used as a back-up fuel for up to 3,000 hours per year between the two CTs, will have a maximum sulfur content limit of 0.05 percent, by weight. The facility is subject to PSD NSR and BACT for SO_2 and H_2SO_4 mist emissions because the proposed increase in annual SO_2 and H_2SO_4 mist emissions exceeds the significant emission rates. The use of natural gas as the primary fuel and limited use of fuel oil represents BACT for these pollutants. Compliance with the SO_2 and H_2SO_4 mist emission standards will be demonstrated by fuel analysis, stack testing, and/or continuous emission monitoring.

CO and VOC emissions will be minimized by combustion control to assure proper fuel mixing and complete fuel combustion. The CO emissions from the proposed combined cycle turbines using dry low-NO_x combustors are 20 ppmvd @ 15% O_2 for natural gas firing and 25 ppmvd @ 15% O_2 for fuel oil firing using water injection. VOC emissions have been based on exhaust concentrations of 5 and 10 ppmvd for natural gas and fuel oil firing, respectively. The facility is subject to PSD NSR and BACT for CO and VOC emissions because the proposed increase in annual CO and VOC emissions exceeds the significant emission rates. Compliance with the emission standards will be determined by stack tests.

The facility is subject to PSD NSR for Be and As. These pollutants are caused primarily by the contaminants in the fossil fuels. Emissions will be controlled by limiting the quantity of fossil fuel that can be burned. Compliance for the pollutants shall be determined by stack tests.

The following table summarizes the maximum emissions of air pollutants subject to PSD review:

Pollutant	Emissions (TPY) Gas*	Oil*	Total**	PSD Significant Emission Rate (TPY)
NO_x	911	525	1139	40
SO_2	44	150	175	40
CO	622	136	614	100
PM/PM_{10}	61	100	145	15
VOC	88	31	99	40
Be	Neg.	0.007	0.007	0.0004
H_2SO_4 Mist	9	33	38	7
As	Neg.	0.014	0.014	Any

* The emissions for gas and oil are based on the worst case ambient temperature condition, which is 32°F, and each CT operating up to 8760 hours on gas and 1500 hours on fuel oil.

** The emissions are based on the ambient temperature of 59°F and each CT operating 7260 hours on gas and 1500 hours on fuel oil. These emissions will be the maximum allowables from the two CTs if any fuel oil is burned at the facility during the year.

IV. AIR QUALITY REPORT

A. Introduction

The proposed project will emit eight pollutants in PSD significant amounts. These pollutants are SO_2, PM/PM_{10}, NO_x, CO and VOC, along with the non-criteria pollutants As, Be, and 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, PM_{10}, and NO_2);
* An Ambient Air Quality Standards (AAQS) analysis;
* An analysis of impacts on soils, vegetation, 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 of Environmental Protection (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 Department has determined that the application complies with the applicable provisions of the stack height regulations as revised by EPA on July 8, 1985 (50 FR 27892). Portions of the regulations have been remanded by a panel of the U.S. Court of Appeals for the D.C. Circuit in NRDC v. Thomas, 838 F. 2d 1224 (D.C. Cir. 1988). Consequently, this permit may be subject to modification if and when EPA revises the regulation in response to the court decision. This may result in revised emission limitations or may affect other actions taken by the source owners or operators." A discussion of the modeling procedure 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 NSR. 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 sources not included in the modeling.

Table 1 shows that NO_2 and CO impacts from the project are predicted to be less than the de minimus levels. Therefore, preconstruction ambient air quality monitoring is not required for these two pollutants. H_2SO_4 mist, As, and VOC impacts for comparison with de minimus levels are not shown in this table. There are no monitoring de minimus levels or acceptable monitoring techniques for H_2SO_4 mist and As, and the net emissions increase of

VOC is compared to a de minimus monitoring emission rate in tons per year, not a concentration level. For this project, the net emissions increase of VOC is less than the de minimus emissions rate of 100 tons per year. For these reasons, preconstruction ambient air monitoring for H_2SO_4 mist, As and VOC is not required.

Table 1 also shows that SO_2, PM_{10}, and Be impacts from the project are predicted to be greater than de minimus levels. Maximum Be impact is predicted to be greater than the de minimus monitoring level for the 50 percent operating load only. For baseload operation, the maximum predicted Be impact is less than the de minimus monitoring level. In addition, maximum predicted Be impacts are well below the applicable Ambient Reference Concentrations (ARC) shown in Table 7. Therefore, no preconstruction monitoring for Be is required for this project. Preconstruction ambient air quality monitoring, however, is required for SO_2 and PM_{10}. Previously existing representative monitoring data from SO_2 monitors in Mulberry and Nichols and a PM_{10} monitor in Homeland are used to fulfill the monitoring requirements for these two pollutants and to establish background concentrations for use in the AAQS analysis. Background concentrations for PM_{10} and SO_2 are given in the AAQS table, Table 6.

C. Modeling Procedure

The EPA-approved Industrial Source Complex Short-Term (ISCST2) dispersion model was used to evaluate the pollutant emissions from the proposed project, the adjacent existing Hardee facility 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 sources, building wake downwash, and various other input and output features. A series of specific model features, recommended by the EPA, are referred to as the regulatory options. The applicant used the EPA recommended regulatory options in each modeling scenario. Direction-specific downwash parameters were used for all sources for which downwash was considered.

Initially, the applicant conducted preliminary modeling for the purpose of determining the worst case fuel/load/operation/temperature scenarios for the proposed project. This preliminary modeling was based on fuel oil combustion since hourly emissions are generally higher with the use of fuel oil than with natural gas. Modeling was performed for three operating loads (100, 75, and 50 percent) at two temperatures (32°F and 95°F) for both simple cycle and combined cycle operation. In general, the "worst case" predicted 1-hour, 8-hour, and 24-hour ground-level ambient air quality impacts occur during 50 percent load conditions at an ambient temperature of 95°F and combined cycle operation; and, the "worst case" 3-hour and annual concentrations occur during 75 percent load conditions and combined cycle operation. These "worst case" conditions were used as input in the significant impact analysis. For determination of the proposed project's significant impact area, the receptor grid consisted of 397 receptors located at the fenced property and at distances of 0.1, 0.2, 0.3, 0.4, 0.6, 1.0, 1.5, 2.0, 3.0, 4.0, and 5.0 km along 36 radials with each radial spaced at 10-degree intervals. For the AAQS and PSD Class II analyses, receptor grids were based on the size of the significant impact area for each pollutant. As shown in Table 2, SO_2 and PM_{10} maximum predicted impacts were greater than significant impact levels. The radius of significant impact for both pollutants is approximately 1 km. Therefore, the receptor grids were located within 1 km of the proposed project at the fenced property and at the following distances: 0.1, 0.2, 0.3, 0.4, 0.5, 0.6, 0.8, and 1.0 km along 36 radials with each radial spaced at 10-degree intervals.

The Chassahowitzka National Wilderness Area (CWNA) is a PSD Class I area that is located 130 km from the project site at its closest point. In the PSD Class I analysis, CWNA is represented by 13 Department-approved standard discrete receptors. For the PSD Class I analysis, the ISCST2 model was used initially as a screening model for estimating impacts on the CWNA. The MESOPUFF II long range transport model was used for a more refined SO_2 impact assessment.

Meteorological data used in the ISCST2 model to determine air quality impacts consisted of a concurrent 5-year period of hourly surface weather observations and twice-daily upper air soundings from the National Weather Service (NWS) station at Tampa. The 5-year period of meteorological data was from 1982 through 1986. The NWS station at Tampa, located approximately 65 km west-northwest of the Hardee site, was selected for use in the study because it is the closest primary weather station to the study area and is most representative of the plant site. The surface observations included wind direction, wind speed, temperature, cloud cover and cloud ceiling.

Since five years of data were used, the highest, second-highest 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, 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 stated in the section above, the maximum air quality impacts due to SO_2 and PM_{10} emissions from the proposed project are greater than the significant impact levels. The radii of significant impact for SO_2 and PM_{10} are approximately 1 km.

E. PSD Increment Analysis

1. Class II Area

The PSD increment represents the amount that new sources in an area may increase ambient ground level concentrations of a pollutant. Atmospheric dispersion modeling, as previously described, was performed to quantify the amount of PSD increment consumed. The results, summarized in Table 3, show that the maximum SO_2 and PM_{10} PSD increment consumption will not exceed the allowable Class II PSD increments.

2. Class I Area

A proposed source subject to PSD NSR must conduct a dispersion modeling analysis of its impacts on any PSD Class I area located near the source. The closest receptor point in the Class I CWNA is approximately 130 km from the Hardee project site. Using the ISCST2 model, the applicant determined the maximum predicted impacts from the proposed Hardee Unit 3 only. These impacts were then compared to the National Park Service's (NPS) significant impact levels as shown in Table 4. The results in this table show that SO_2 is the only pollutant with impacts greater than these levels.

Based on the results for SO_2, a more refined PSD Class I impact assessment using ISCST2 and MESOPUFF II was performed. All increment-consuming sources in the area of the CWNA were input into these models. Table 5 shows the results of this assessment. The maximum predicted 3-hour and 24-hour impacts due to all increment-consuming sources exceed the PSD Class I increments on numerous occasions. In order to assess the proposed project's contribution to any predicted Class I exceedances, an analysis was performed to determine all time periods and receptors at which an exceedance was predicted to occur. Both ISCST2 and MESOPUFF II were used in this assessment. For each case, the proposed project's impact was determined and compared to the NPS recommended significant impact levels. The impact of the project was always less than these significance levels at any receptor and for any time period when there were predicted exceedances or violations of increments. Therefore, the proposed project will not contribute significantly to any predicted exceedance or violation of Class I increments and may be permitted by Department rules.

F. AAQS Analysis

For the pollutants subject to an AAQS review, the total impact on ambient air is obtained by adding a "background" concentration to the maximum modeled concentration. This "background" concentration takes into account all sources of a particular pollutant that are not explicitly modeled. The results of the AAQS analysis for SO_2 and PM_{10} are summarized in Table 6. Emissions from the proposed facility are not expected to cause or contribute to a violation of an AAQS.

G. Non-criteria Pollutants

As, Be and H_2SO_4 mist are non-criteria pollutants, which means that neither national AAQS nor PSD increments have been defined for these pollutants. The BACT determination specifies that the control of these pollutants will be through the use of a very clean fuel oil and by limiting the amount of fuel oil consumed. The fuel oil sulfur content will have a maximum limit of 0.05%, by weight.

H. Air Toxics Analysis

The maximum impacts of regulated and non-regulated toxic air pollutants that will be emitted by the project are presented in Table 7. Each pollutant's maximum 8-hour, 24-hour, and annual impact is compared to the Department's draft ARC. As shown in the table, all predicted impacts are less than their respective ARC.

V. ADDITIONAL IMPACTS ANALYSIS

A. Impacts on Soils, Vegetation, and Wildlife

The maximum ground-level concentrations predicted to occur for SO_2, PM_{10}, CO and NO_x, as a result of the proposed project, including background concentrations and all other nearby sources, will be below the associated AAQS. The AAQS are designed to protect both the public health and welfare. As such, this project is not expected to have a harmful impact on soils and vegetation in the PSD Class II area. An air quality related values (AQRV) analysis was done by the applicant for the Class I area. No significant impacts on this area are expected.

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. The results indicate that the maximum visibility impacts do not exceed the screening criteria inside or outside the Everglades National Park Class I area. As a result, there is no significant impact on visibility predicted for the Class I area.

C. Growth-Related Air Quality Impacts

There will be a small number of temporary construction workers during construction and even smaller number of new permanent workers after the project is completed. 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 HRSG stacks and bypass stacks for this project will be 27.4 m (90 ft) and 22.9 m (75 ft), respectively. These stacks will not exceed the GEP stack height and will comply with GEP stack height regulations. However, these stacks will be less than GEP; therefore, the potential for building downwash to occur was considered in the modeling analysis for these stacks.

VI. CONCLUSION

Based on the information presented by the applicant in the above analysis, the Department has been provided reasonable assurances that the proposed project to construct two CTs, associated HRSGs and a steam turbine-generator for a nominal generation of 440 MW, as described in the application and subject to the conditions of approval proposed herein, will not cause or contribute to any violation of any PSD increment, ambient air quality standard, or any other technical provision of Chapters 62-212 and 62-4 of the Florida Administrative Code.

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VI. CONCLUSION

Based on the information presented by the applicant in the above analysis, the Department has been provided reasonable assurances that the proposed project to construct two CTs, associated HRSGs and a steam turbine-generator for a nominal generation of 440 MW, as described in the application and subject to the conditions of approval proposed herein, will not cause or contribute to any violation of any PSD increment, ambient air quality standard, or any other technical provision of Chapters 62-212 and 62-4 of the Florida Administrative Code.

Table 1. Maximum Air Quality Impacts for Comparison to the De Minimus Ambient Levels.

Pollutant	Avg. Time	Max Predicted Impact (ug/m^3)	De Minimus Level (ug/m^3)
SO_2	24-hour	27.8	13
PM_{10}	24-hour	21.5	10
NO_2	Annual	0.6	14
CO	8-hour	115	575
Beryllium *	24-hour	0.0014	0.001

* non-criteria pollutant

Table 2. Significant Impact Analysis for Class II Area

Pollutant	Averaging Time	Max. Predicted Impact (ug/m^3)	Significant Impact Level (ug/m^3)
NO_2	Annual	0.59	1
SO_2	Annual	0.18	1
	24-hour	27.8	5
	3-hour	65.1	25
PM_{10}	Annual	0.12	1
	24-hour	21.5	5
CO	8-hour	115	500
	1-hour	255	2000

Table 3. PSD Class II Increment Analysis

Pollutant	Averaging Time	Max. Predicted Impact[1] (ug/m^3)	Allowable Increment (ug/m^3)
SO_2	Annual	-4.0	20
	24-hour	45.4	91
	3-hour	150	512
PM_{10}	Annual	0.6	17
	24-hour	14	30

1. Highest, second-highest value over a five year period for 3-hour and 24-hour averaging times.

Table 4. Significant Impact Analysis for PSD Class I Area

Pollutant	Averaging Time	Max. Predicted Impact (ug/m^3)	National Park Service (NPS) Significant Impact Level (ug/m^3)
NO_2	Annual	0.022	0.025
SO_2	Annual	0.012	0.025
	24-hour	0.30	0.07
	3-hour	1.9	0.48
PM_{10}	Annual	0.008	0.08
	24-hour	0.20	0.33

Table 5. PSD Class I Increment Analysis

Pollutant	Averaging Time	Max. Predicted Impact[1] (ug/m^3)	Allowable Increment (ug/m^3)
SO_2	Annual	0.3	2
	24-hour	6.4[2]	5
	3-hour	26.1[2]	25

1. Highest, second-highest value over a five year period for 3-hour and 24-hour averaging times.
2. The project has less than significant impacts for all predicted exceedances of SO_2 increments.

Table 6. Ambient Air Quality Impact Analysis

Pollutant	Averaging Time	Modeled Sources Impact (ug/m^3)	Background Conc. (ug/m^3)	Max Predicted Impact[1] (ug/m^3)	Florida AAQS (ug/m^3)
SO_2	Annual	18	11	29	60
	24-hour	88	50	138	260
	3-hour	178	256	434	1,300
PM_{10}	Annual	4	20	24	50
	24-hour	31	70	101	150

1. Highest, second-highest value over a five year period for 3-hour and 24-hour averaging times.

Table 7. Air Toxics Analysis

	8- hour		24- hour		Annual	
Pollutant	Impact (ug/m^3)	ARC (ug/m^3)	Impact (ug/m^3)	ARC (ug/m^3)	Impact (ug/m^3)	ARC (ug/m^3)
Arsenic	0.0055	2	0.0027	0.48	0.000017	0.00023
Beryllium	0.0028	0.02	0.0014	0.0048	0.000009	0.00042
Barium	0.022	5	0.011	1.2	0.00007	50
Cadmium	0.012	0.5	0.006	0.12	0.000037	0.00056
Chlorine	0.028	15	0.014	3.6	.00007	0.4
Chromium+6	0.053	0.5	0.026	0.12	0.00003	0.000083
Cobalt	0.01	0.5	0.005	0.12	-	-
Fluoride	0.037	25	0.018	6	-	-
Formaldehyde	0.45	12	0.22	2.88	0.0014	0.077
Antimony	0.024	5	0.012	1.2	0.00008	0.3
Manganese	0.38	50	0.19	12	.00099	0.4
Mercury	0.0099	0.5	0.0048	0.12	0.000026	0.3
Nickel	1.34	10	0.66	2.4	0.0007	0.0042
Selenium	0.026	0.48	0.013	2	-	-
Vanadium	0.078	0.5	0.038	0.12	0.0002	2
Zinc	1.77	10	0.86	2.4	-	-

Note: ARC = Ambient Reference Concentration

Department of Environmental Protection

Lawton Chiles
Governor

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Tallahassee, Florida 32399-2400

Virginia B. Wetherell
Secretary

PERMITTEE:
Seminole Electric Cooperative Incorporated
P.O. Box 272000
Tampa, FL 33688-2000

Permit Number: PSD-FL-214 (PA-89-25SA)
Expiration Date: January 1, 2000
County: Polk & Hardee
Latitude/Longitude: 27°38'30"N 81°57'45"W
Project: 440 MW Combined Cycle Power Plant

This permit is issued under the provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Chapters 62-212 and 62-4. 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 and specifically described as follows:

For a 440 MW combined cycle power plant consisting of two 150 MW combustion turbines (CTs), two heat recovery steam generators (HRSGs), a 140 MW steam turbine generator and a 4.4 million gallon fuel oil storage tank. The maximum heat input at 32°F is 1,799 MMBtu/hr/CT (natural gas) and 1,972 MMBtu/hr/CT (oil). The plant will be located at the Polk and Hardee County site near Bowling Green, Florida which is also the site of a 295 MW power plant which is operated by TECO Power Services. The combustion turbines are to be Westinghouse Model 501F or equivalent and equipped with dry low NO_x combustors or an equivalent system for natural gas firing and wet injection for fuel oil firing. The CT will be fired with natural gas and No. 2 low sulfur fuel oil with a sulfur content limit not to exceed 0.05 percent, by weight, as a back-up only.

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

Attachments are listed below:

1. Seminole Electric Cooperative Incorporated's (SECI) application received May 9, 1994.
2. Department's letters dated June 27, September 21, and November 16, 1994.
3. SECI's letters dated August 26, October 6, and November 23, 1994.
4. SECI's letter dated February 9, 1995.

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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.

GENERAL CONDITIONS:

7. The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law and at a reasonable time, access to the premises, where the permitted activity is located or conducted to:

a. Have access to and copy 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.

GENERAL CONDITIONS:

11. This permit is transferable only upon Department approval in accordance with Rules 62-4.120 and 62-730.300, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.

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

13. This permit also constitutes:

(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.

GENERAL CONDITIONS:

15. When requested by the Department, the permittee shall within a reasonable time furnish any information required by law which is needed to determine compliance with the permit. If the permittee becomes aware that relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be corrected promptly.

SPECIFIC CONDITIONS:

The construction and operation of the project shall be in accordance with all applicable provisions of Chapters 62-210 thru 62-297 and 62-4, Florida Administrative Code (F.A.C.), and 40 CFR 60, Subpart GG, Appendix A, Appendix B, and Appendix F (1994 version). The following emission limitations and conditions reflect the BACT determinations for the 300 megawatts (MW; two 150 MW combined cycle combustion turbines) of generating capacity. Each combustion turbine (CT) will be connected to a heat recovery steam generator (HRSG), which will recover the waste heat to produce steam for utilization in a single 140 MW (net) steam generator. There is no fuel firing in the associated HRSG. The facility will have a total nominal generating capacity of 440 MW (net). In addition to the foregoing, the project shall comply with the following Specific Conditions:

A. General Requirements

1. Pursuant to Rule 62-212.200(56), F.A.C., Potential to Emit (PTE), the maximum heat input to each Westinghouse 501F CT, or equivalent, at an ambient temperature of 32°F, shall neither exceed 1,799 MMBtu/hr while firing natural gas nor 1,972 MMBtu/hr while firing fuel oil.

2. Pursuant to Rule 62-212.200(56), F.A.C., PTE, the CTs may operate continuously, i.e., 8,760 hrs/year.

3. Pursuant to Rule 62-212.200(56), F.A.C., PTE, only natural gas or No. 2 fuel oil is allowed to be fired in the CTs. The maximum sulfur content limit of the No. 2 fuel oil shall not exceed 0.05 percent, by weight.

4. Pursuant to Rule 62-212.200(56), F.A.C., PTE, the maximum No. 2 fuel oil consumption allowed to be burned is 41,751,000 gallons per year, which is equivalent to 1500 hours per CT per year of operation (not to exceed 3,000 hrs/yr between the two CTs) at full-load. The No. 2 fuel oil is to be used as a back-up fuel only.

5. Pursuant to Rule 62-296.310(3),F.A.C., Unconfined Emissions of Particulate Matter (PM), the emissions of unconfined PM shall be minimized during the construction period by covering or watering dust generating areas.

SPECIFIC CONDITIONS:

B. Emission Limits

1. Pursuant to Rule 62-212.410, F.A.C., BACT, the maximum allowable emission limitations from two CTs, when firing natural gas or No. 2 fuel oil, shall not exceed the following:

MAXIMUM ALLOWABLE EMISSION LIMITATIONS

POLLUTANT	FUEL	CONCENTRATION	lbs/hr(a)	TPY(b)	TPY(TOTAL)c
NO_x	Gas	15 ppmvd(d)	104	911	1139
	Oil	42 ppmvd(e)	350	525	
CO	Gas	20 ppmvd	71	622	614
	Oil	25 ppmvd	91	136	
PM/PM_{10}	Gas		7	61	145
	Oil		67	100	
SO_2	Gas		5	44	175
	Oil		100	150	
VOC	Gas	5 ppmvd	10	88	99
	Oil	10 ppmvd	21	31	
Sulfuric Acid Mist	Gas		1	9	38
	Oil		22	33	
Beryllium	Oil		0.0049	0.007	0.007
Arsenic	Oil		0.0097	0.014	0.014
Visible Emissions	Gas		≤ 10 percent opacity		
	Oil		≤ 10 percent opacity		

(a) The emission limitations in lbs/hr/CT are a 1-hour average.

(b) The annual emission limitations (TPY) for natural gas are based on two CTs operating at full load for 8,760 hours per year. The annual emission limitations (TPY) for fuel oil are based on the equivalent of full-load operation for a maximum of 1500 hours per year for each of the two CTs (not to exceed 3,000 hrs/yr between the two CTs). The emission calculations are also based at a worst case ambient temperature of 32°F.

(c) Maximum allowable emissions from two CTs if any fuel oil is burned at the facility during the year. The emission calculations are also based at an ambient temperature of 59°F.

SPECIFIC CONDITIONS:

(d) The natural gas NO_X allowable emission limitation of 15 ppmvd is corrected to 15 percent O_2. Compliance shall be determined through the initial and annual compliance tests.

(e) The fuel oil NO_X allowable emission limitation of 42 ppmvd is corrected to 15 percent oxygen. Compliance shall be determined through the initial and annual compliance tests. The annual compliance test will be required if the fuel oil is fired for more than 400 hours in the preceding 12-months.

2. The following estimated CT emissions are tabulated for PSD tracking purposes only:

ESTIMATED EMISSIONS

POLLUTANT	FUEL	TPY
Lead	Oil(a,b)	0.16
Fluoride	Oil(a,b)	0.090
Mercury	Gas(c)	0.0003
	Oil(a,b)	0.024

(a) The annual emission limitations (TPY) for fuel oil are based on full-load operation for a total of 3,000 hours per year between the two CTs at an ambient temperature of 59°F.

(b) The No. 2 fuel oil shall have a maximum sulfur content limit of 0.05 percent, by weight.

(c) The annual emission limitation (TPY) for natural gas is based on two CTs operating at full-load for 8,760 hours per year at an ambient temperature of 59°F.

3. The permittee will install a dry low-NO_X combustor system or an equivalent system on each CT. The permittee shall make every practicable effort to achieve the lowest possible NO_X emission rate, but must not exceed 15 ppmvd at 15 percent O_2 per CT on a continuous basis when firing natural gas.

4. After the initial compliance tests on the CTs, the permittee shall operate a certified continuous emissions monitor for NO_X emissions and collect 12 months of monitoring data. The monitor will, at a minimum, meet the requirements of 40 CFR 60, Appendix F's quality assurance procedures. Within 18 months after the initial compliance test, the permittee shall prepare and submit

SPECIFIC CONDITIONS:

for the Department's review an engineering report regarding the collection and the analysis of the data gathered from the monitor. In addition, this report shall include a conclusion regarding the lowest NO_X emission rate that can be consistently achieved with a reasonable operating margin, taking into account long-term performance expectations and assuming good operating and maintenance practices. The report shall also include results of the testing requirements of 40 CFR 60, Appendix F's quality assurance procedures and the actual CEMS data for the period of the study in an acceptable format.

5. The Department will make a determination as to whether to seek to revise the permitted NO_X emission limitation and will base it on the engineering data report submitted by the permittee. If the data demonstrate that a NO_X emission rate of less than 15 ppmvd at 15 percent O_2 is consistently achievable, the NO_X emission limit may be adjusted accordingly, but not lower than 9 ppmvd at 15 percent O_2.

6. Excess emissions from a turbine resulting from start up, shutdown, malfunction, or load change shall be reported in accordance with 40 CFR 60.334(c) and accepted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized, but in no case exceed two hours in any 24-hour period unless specifically authorized by the Department for a longer duration. The permittee shall provide a general description of the procedures to be followed during periods of start up, shutdown, malfunction, or load change to ensure that the best operational practices to minimize emissions will be adhered to and the duration of any excess emissions will be minimized. The description should be submitted to the Department along with the initial compliance test data. The description may be updated as needed by submitting such update to the Department within thirty (30) days of implementation.

C. Performance Testing

1. Initial (I) compliance tests shall be performed on each CT using both fuels. Testing of emissions shall be conducted at 95-100% of the manufacturer's rated heat input based on the average ambient air temperature for the CT during the test. Annual (A) compliance tests shall be performed on the CT with the fuel(s) used for more than 400 hours in the preceding 12-month period. Tests at permit renewal shall also be performed on the non-PSD pollutants. Tests and procedures shall be in accordance with 40 CFR 60.335. Tests shall be conducted using EPA reference methods in accordance with 40 CFR 60, Appendix A, as adopted by reference in Chapter 62-297, F.A.C, and follows:

a. Reference Method 5B for PM (I, A: for oil only; assumption is that all PM is PM_{10}).

SPECIFIC CONDITIONS:

b. Reference Method 9 for VE (I, A).

c. Reference Method 10 for CO (I, A).

d. Reference Method 20 for NOx (I, A).

e. Reference Method 18 or 25A for VOC (I, A).

f. Reference Method 8 for H_2SO_4 Mist (I, A).

g. Trace elements of Beryllium (Be) and Arsenic (As) shall be tested (I, for oil only) using EMTIC Interim Test Methods. As an alternative, EPA Method 104 for Be may be used; or, Be and As may be determined from fuel analysis using either Method 7090 or 7091 and sample extraction using Method 3040, as described in the EPA solid waste regulations SW 846.

h. ASTM D4294 (or equivalent) for sulfur content of distillate oil (I and A), which can be used for determining SO_2 emissions annually.

i. ASTM D1072-80, D3031-81, D4084-82, or D3246-81 (or equivalent) for sulfur content of natural gas (I; and, A if deemed necessary by the Department).

j. No other methods may be used for compliance testing unless prior Departmental approval has been received in writing.

2. The maximum sulfur content of the fuel oil shall not exceed 0.05 percent, by weight. Compliance shall be demonstrated in accordance with the requirements of 40 CFR 60.334(b), which imposes testing for the sulfur content of the fuel oil in the storage tanks on each occasion that fuel is transferred to the storage tanks from any other source. Testing for the fuel oil lower heating value shall also be conducted on the same schedule.

D. Monitoring Requirements

Monitoring of operations shall be in accordance with 40 CFR 60.334. Also, and for each CT, the permittee shall install, operate, and maintain a continuous emission monitoring system (CEMS) to monitor nitrogen oxides in accordance with 40 CFR 60, Appendix F, and, if necessary, a diluent gas (CO_2 or O_2). The Federal Acid Rain Program requirements of 40 CFR 75 shall apply when those requirements are adopted and if applicable.

1. Each CEMS shall meet performance specifications of 40 CFR 60, Appendix B.

SPECIFIC CONDITIONS:

2. CEMS data shall be recorded and reported in accordance with Rule 62-297.500, F.A.C.; 40 CFR 60; and, 40 CFR 75, if it becomes applicable. The record shall include periods of start up, shutdown, load change, and malfunction.

3. 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.

4. The procedures under 40 CFR 60.13 shall be followed for installation, evaluation, and operation of all CEMS. If applicable, 40 CFR 75 shall apply when the Federal Acid Rain Program is adopted.

5. For purposes of the reports required under this permit, excess emissions are defined as any calculated average emission rate, as determined pursuant to Condition B.6 herein, which exceeds the applicable emission limitation in Condition B.1.

E. Notification, Reporting and Recordkeeping

1. To determine compliance with the natural gas and fuel oil firing heat input limitation, the permittee shall maintain daily records of natural gas and fuel oil consumption for each turbine, and provide the heating value for each fuel during the compliance test. All records shall be maintained for a minimum of five years after the date of each record and shall be made available to representatives of the Department upon request.

2. The project shall comply with all the applicable requirements of Chapters 62-210 through 62-297 and 62-4, F.A.C., and 40 CFR 60, Subparts A and GG. The requirements shall include:

a. 40 CFR 60.7(a)(1) - By postmarking or delivering notification of the start of construction no more than 30 days after such date.

b. 40 CFR 60.7(a)(2) - By postmarking or delivering notification of the anticipated date of the initial start up of each CT not less than 30 days prior to such date.

c. 40 CFR 60.7(a)(3) - By postmarking or delivering notification of the actual start up of each turbine within 15 days after such date.

SPECIFIC CONDITIONS:

d. 40 CFR 60.7(a)(5) - By postmarking or delivering notification of the date for demonstrating the CEMS performance, no less than 30 days prior to such date.

e. 40 CFR 60.7(a)(6) - By postmarking or delivering notification of the anticipated date for conducting the opacity observations no less than 30 days prior to such date.

f. 40 CFR 60.7(b) - By initiating a recordkeeping system to record the occurrence and duration of any start up, shutdown, load change and malfunction of a turbine, malfunction of the air pollution control equipment, and the periods when the CEMS is inoperable.

g. 40 CFR 60.7(c) - By postmarking or delivering a quarterly excess emissions and monitoring system performance report within 30 days after the end of each calendar quarter. This report shall contain the information specified in 40 CFR 60.7(c) and (d).

h. 40 CFR 60.8(a) - By conducting all performance tests within 60 days after achieving the maximum turbine and boiler firing rates, but not more than 180 days after the initial start up of each CT.

i. 40 CFR 60.8(d) - By postmarking or delivering notification of the date of each performance test required by this permit at least 30 days prior to the test date; and,

j. Rule 62-297.345 - By providing stack sampling facilities for each turbine.

k. All notifications and reports required by this specific condition shall be submitted to the Department's Southwest District office. Performance test results shall be submitted within 45 days of completion of such test.

3. The following information shall be submitted to the Department's Bureau of Air Regulation within 90 days after the permittee has made the selection of the following:

a. Description of the final selection of the turbines for installation at the facility. The descriptions shall include the specific make and model numbers and any changes in the proposed method of operation, fuels, emissions or equipment.

b. Description of the CEMS selected. The description shall include the type of sensors and the manufacturer and model numbers of the equipment.

SPECIFIC CONDITIONS:

4. The following protocols shall be submitted to the Department's Southwest District office for approval:

a. CEMS Protocol - Within 90 days after selection of the CEMS, but prior to the initial startup, a CEMS protocol describing the system, its installation, operating and maintenance characteristics and requirements. The protocol shall meet the requirements of 40 CFR 60.13, Appendix B and Appendix F.

b. Performance Test Protocol - At least 90 days prior to conducting the initial performance tests required by this permit, the permittee shall submit to the Department's Southwest District office 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. The Department shall approve the testing protocol provided that it meets the requirements of this permit.

c. Heat Input Curves - Within 90 days after selection of the turbine, manufacturer's curves or equations of heat input corrections tc other temperatures shall be provided to the Department. Subject to the approval by the Department for tecnical validity while applying sound engineering principles, the manufacturer's curves shall be used to establish the heat input rates over a range of temperatures for the purposes of compliance determination.

F. Modifications

The permittee shall give written notification to the Department when there is any modification to this facility 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 plans, if necessary. Such notice shall include, but not be limited to, information describing the precise nature of the change; modifications to any emission control system; production capacity of the facility before and after the change; and, the anticipated completion date of the change.

G. No. 2 Fuel Oil Storage Tank

The permittee shall be in compliance with the monitoring requirements of 40 CFR 60.116b(a) and (b).

SPECIFIC CONDITIONS:

H. Additional General Conditions

1. Pursuant to Rule 62-4.090, F.A.C., the permittee, for good cause, may request that this construction permit be extended. Such a request shall be submitted to the Department's Bureau of Air Regulation prior to 60 days before the expiration of the permit.

2. Pursuant to Rules 62-4.055 and 62-4.220, F.A.C., an application for an operation permit must be submitted to the Department's Southwest 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.

**STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION**

____
Virginia B. Wetherell, Secretary

Best Available Control Technology (BACT) Determination
Seminole Electric Cooperative Incorporated (SECI)
Hardee and Polk Counties
PSD-FL-214
PA89-25SA

The applicant proposes to install two combined cycle combustion turbine (CT) generators and associated steam cycle at a facility adjacent to the Hardee Power Station's existing units located in Hardee and Polk Counties. The facility, referred to as Hardee Unit 3, will consist of two 150 megawatt (MW) Westinghouse Model 501F, or equivalent, advanced CTs. Each CT will be connected to a heat recovery steam generator (HRSG), which will recover the waste heat to produce steam for utilization in a single 140 MW (net) steam turbine. The facility will have a total nominal generating capacity of 440 MW (net). The primary fuel for the CTs will be natural gas, with distillate fuel oil containing a maximum sulfur content of 0.05 percent, by weight, designated as the backup fuel. Natural gas will be transported to the facility via pipeline and fuel oil will be delivered by truck and stored on site in a 4.4 million gallon above ground storage tank.

In 1990, the Hardee Power Station was certified for 660 MW of generation in a phased construction schedule as follows:

1. TECO Power Services - 295 MW (1993) (Phase 1A).
2. TECO Power Services - 145 MW (future unit) (Phase 1B).
3. SECI - 220 MW (date unspecified) (Phase 2).

This new certification does not change Phases 1A and 1B, above, but will increase the SECI certified generation (Phase 2) from 220 MW to 440 MW, with an inservice date of January, 1999. A simplified flow diagram of Hardee Unit 3 is shown in Figure 1. Because of the phased construction activity, the Department looked at the total emissions from the Phase 2 project to see if any additional pollutants (i.e., Hg, Pb, etc.) should be reviewed from the BACT determination process.

The applicant has indicated the maximum annual air pollutant emission rates associated with the facility, based on 100 percent capacity factor and type of fuel fired, to be as follows:

Pollutant	Emissions (TPY) Fuel Oil	Natural Gas	Natural Gas-Steam for Power Augmentation	Total	PSD Significant Emission Rate (TPY)	Subject to PSD Review?
Potential Emissions (Without Power Augmentation)[a]						
SO_2	140.1	34.8	NA	174.9	40	Yes
PM/PM_{10}	94.1	50.4	NA	144.5	25/15	Yes
NO_x	466.2	673.2	NA	1,139.4	40	Yes
CO	127.9	486.1	NA	614.0	100	Yes
VOC	29.2	69.5	NA	98.7	40	Yes
Lead	0.16	NA	NA	0.16	0.6	No
Arsenic	0.014	NA	NA	0.014	Any	Yes
Beryllium	0.0069	NA	NA	0.0069	0.0004	Yes
Fluoride	0.090	NA	NA	0.090	3	No
Mercury	0.024	0.0003	NA	0.025	0.1	No
Sulfuric Acid Mist	31.1	6.86	NA	38.0	7	Yes
Potential Emissions (With Power Augmentation)[b]						
SO_2	140.1	25.2	9.32	174.6	40	Yes
PM/PM_{10}	94.1	36.5	14.4	145.1	25/15	Yes
NO_x	466.2	487.7	251.5	1,205.4	40	Yes
CO	127.9	352.2	313.4	793.5	100	Yes
VOC	29.2	50.3	17.9	97.5	40	Yes
Lead	0.16	NA	NA	0.16	0.6	No
Arsenic	0.014	NA	NA	0.014	Any	Yes
Beryllium	0.0069	NA	NA	0.0069	0.0004	Yes
Fluoride	0.090	NA	NA	0.090	3	No
Mercury	0.024	0.0002	0.00009	0.025	0.1	No
Sulfuric Acid Mist	31.1	4.97	1.84	37.9	7	Yes

Note: NA = not applicable.

[a] Emission rates are based on two CTs firing fuel oil for 1,500 hours each and natural gas for 7,260 hours at ambient temperature of 59°F (without power augmentation) and relative humidity of 60 percent.

[b] Emission rates are based on two CTs firing fuel oil for 1,500 hours each and natural gas for 7,260 hours at ambient temperature of 59°F and relative humidity of 60 percent. Natural gas combustion includes 2,000 hours of steam for power augmentation at ambient temperature of 80°F and relative humidity of 80 percent.

FIGURE 1

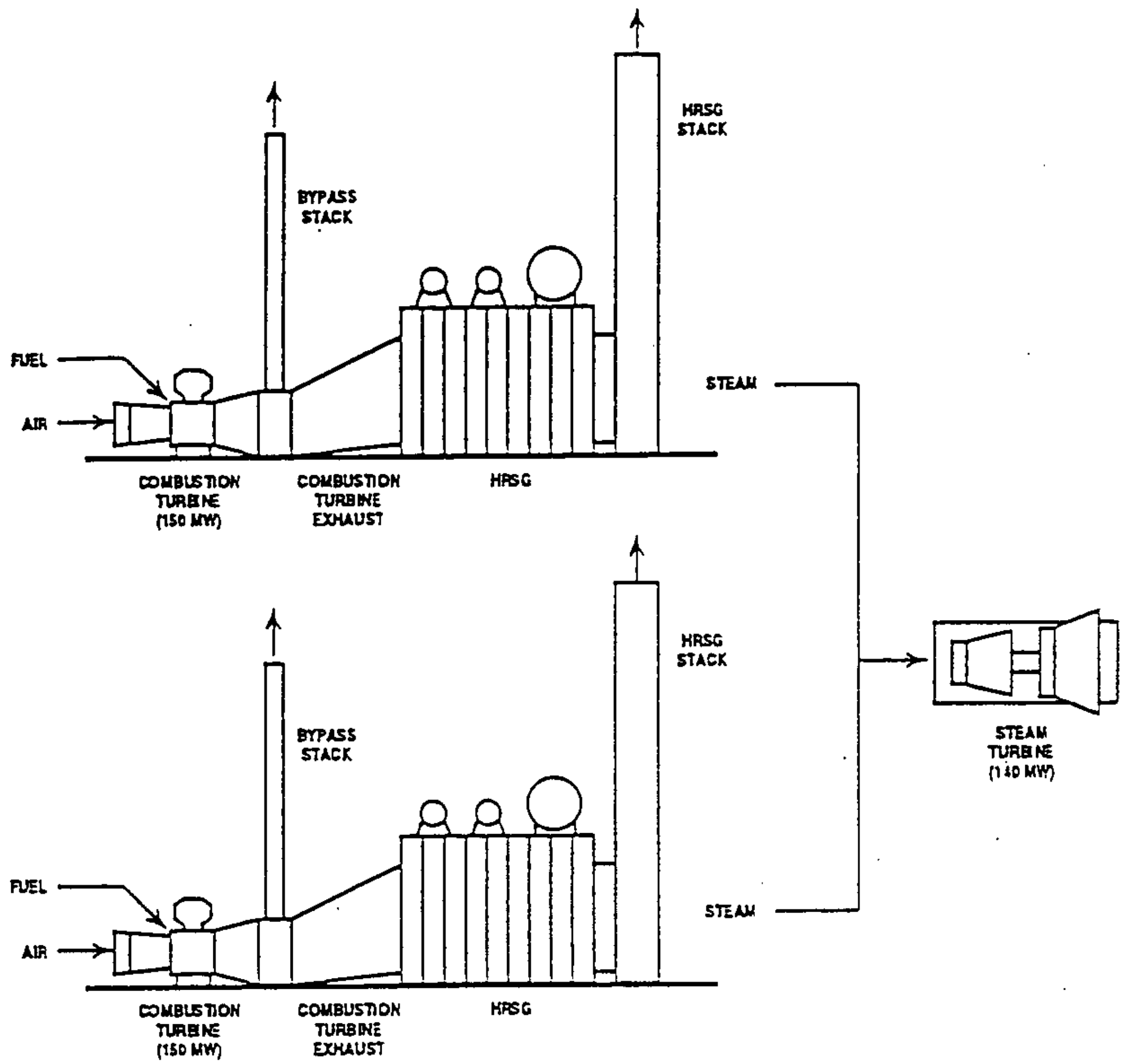

Figure 2-4
Schematic Flow Diagram of Hardee Unit 3 Facility

SEMINOLE ELECTRIC COOPERATIVE INCORPORATED

Rule 62-212.400, Florida Administrative Code (F.A.C.), Stationary Source Preconstruction Review, requires a BACT review for all regulated pollutants emitted in an amount equal to or greater than the significant emission rates listed in the previous table.

Date of Receipt of a BACT Application
May 9, 1994.

BACT Determination Requested by the Applicant

Combined Cycle Combustion Turbines

Pollutant	Fuel: Natural Gas	Fuel: Fuel Oil
NO_x	15 ppmvd @ 15% O_2 at ISO 25 ppmvd @ 15% O_2 at ISO (power augmentation mode) Dry Low NO_x Burners	42 ppmvd @ 15 % O_2 at ISO Water Injection Limited Fuel Oil Operation
SO_2	Firing with Natural Gas	Low Sulfur Fuel Oil (0.05 %, by weight) Limited Fuel Oil Operation
CO	20 ppmvd 50 ppmvd (power augmentation mode) Combustion Control	25 ppmvd Combustion Control Limited Fuel Oil Operation
VOC	5 ppmvd Combustion Control	10 ppmvd Combustion Control
PM/PM_{10}	Combustion Control	Combustion Control Limited Fuel Oil Operation
Beryllium	Good Quality Fuel	Good Quality Fuel Limited Fuel Oil Operation
Inorganic Arsenic	Good Quality Fuel	Good Quality Fuel Limited Fuel Oil Operation
Benzene	Combustion Control	N/A

BACT Determination Procedure

In accordance with Rule 62-212.410, F.A.C., BACT Review, Stationary Source - Preconstruction Review, the BACT determination is based on the maximum degree of reduction of each pollutant emitted which the 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 determinations 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 source in question the most stringent control available for a similar or identical source or source category. If it is shown that this level of control is technically or economically infeasible for the source 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 combined cycle power plants can be grouped into categories based upon what control equipment and techniques are available to control emissions from these facilities. Using this approach, the emissions can be classified as follows:

- Combustion Products (e.g., particulate matter and trace metals). Controlled generally by good combustion of clean fuels.

- Products of Incomplete Combustion (e.g., CO and VOCs). Control is largely achieved by proper combustion techniques.

- Acid Gases (e.g., SO_2, NO_x). Controlled generally by gaseous control devices and fuel quality.

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.

BACT POLLUTANT ANALYSIS

COMBUSTION PRODUCTS

Particulate Matter (PM/PM_{10})

The design of the CT system ensures that PM/PM_{10} will be minimized by combustion control and the use of clean fuels. The PM/PM_{10} emissions from the CTs, when burning natural gas and fuel oil, will not exceed 7 lbs/hr/CT (gas) and 67 lbs/hr/CT (oil) for the Westinghouse 501F, or equivalent, (with no power augmentation) at 100% load. The assumption is that all PM emissions are PM_{10} emissions.

Beryllium and Inorganic Arsenic (Be, As)

The Department agrees with the applicant's rationale that there are no feasible methods to control Be, As, and other trace pollutants, except by requiring good quality fuel. Limiting the fuel sulfur content to a maximum of 0.05%, by weight, assures good quality fuel and minimizes any concerns for these pollutants.

PRODUCTS OF INCOMPLETE COMBUSTION

Carbon Monoxide (CO) and Volatile Organic Compounds (VOC)

The emissions of CO exceed the PSD significant emission rate of 100 TPY with the Westinghouse 501F CT. The applicant has indicated that the CO emissions from the proposed combined cycle CTs with dry low-NO_x combustors are 20 ppmvd for natural gas firing (50 ppmvd during power augmentation) and 25 ppmvd for fuel oil firing with water injection. VOC emissions have been based on exhaust concentrations of 5 & 10 ppmvd for natural gas and fuel oil firing, respectively.

The majority of BACT emissions limitations have been based on combustion controls for CO and VOC minimization. Additional control is achievable through the use of catalytic oxidation. Catalytic oxidation is a post-combustion control that has been employed in CO nonattainment areas where regulations have required CO emission levels to be less than those associated with wet injection. These installations have been required to use LAER technology and typically have CO limits in the 10 ppmvd range.

In an oxidation catalyst control system, CO emissions are reduced by allowing unburned CO to react with oxygen at the surface of a precious metal catalyst, such as platinum. Oxidation of CO starts at about 300°F, with efficiencies above 90 percent occurring at temperatures above 600°F. Catalytic oxidation occurs at temperatures 50 percent lower than that of thermal oxidation, which reduces the amount of thermal energy required. For CT/HRSG combinations, the oxidation catalyst can be located directly after the CT or in the HRSG. Catalyst size depends upon the exhaust flow, temperature, and desired efficiency.

The application of oxidation catalyst is not technically feasible for gas turbines fired with fuel oil due to the oxidation of sulfur compounds and excessive formation of H_2SO_4 mist emissions. Catalytic oxidation has not been demonstrated on a continuous basis when using fuel oil.

Use of oxidation catalyst technology would be feasible for a natural gas-fired unit; however, the cost effectiveness of $4,000 per ton of CO removed for the Westinghouse 501F CT unit will have an economic impact on this project.

ACID GASES

Nitrogen Oxides (NO_x)

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

The applicant has stated that BACT for NO_x will be met by using dry low-NO_x combustors to limit emissions to 15 ppmvd (corrected to 15% O_2 at ISO conditions) when burning natural gas (25 ppmvd corrected to 15% O_2 at ISO conditions during power augmentation) and 42 ppmvd (corrected to 15% O_2 at ISO conditions) with water injection and 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.

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 NO_x reduction efficiency, while holding ammonia slip emissions constant, will decrease.

The effect of exhaust gas temperature on NO_x reduction depends on the specific catalyst formulation and reactor design. Generally, SCR units can be designed to achieve effective NO_x control over a 100-300°F operating window within the bounds of 450-800°F. The preferable operating window is within the bounds of 600-750°F for effective NO_x control.

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.

As stated by the applicant, the exhaust temperatures of the proposed combined cycle CTs for this site are between 950°F to 1100°F. However, catalyst can be located in the appropriate temperature range in the HRSG, but the applicant has stated that effective SCR operation will be difficult to maintain under significant load and ambient temperature variations. In this case, application of an SCR system appears to be technically feasible.

Although technically feasible, the applicant has rejected using SCR on the combined cycle units because of economic, energy, and environmental impacts. The applicant has identified the following limitations:

a) Reduced power output.

b) Emissions of unreacted ammonia (slip).

c) Increased H_2SO_4 mist emissions.

d) Disposal of hazardous waste generated (spent catalyst).

e) Ammonium bisulfate and ammonium sulfate particulate matter emissions (ammonium salts) due to the reaction of NH_3 with SO_3 present in the exhaust gases.

f) Cost effectiveness for the application of SCR technology to the project was considered to be \$6,802 per ton of NO_X removed when compared to the use of dry low-NO_X combustors.

Since SCR has been determined to be BACT for several combined cycle facilities, the EPA has clearly stated that there must be unique circumstances to consider the rejection of such control on the basis of economics.

In a recent letter from EPA Region IV to the Department regarding the permitting of a combined cycle facility (Tropicana Products, Inc.), the following statement was made:

> "In order to reject a control option on the basis of economic considerations, the applicant must show why the costs associated with the control are significantly higher for this specific project than for other similar projects that have installed this control system or in general for controlling the pollutant."

For fuel oil firing, the cost associated with controlling NO_X emissions must take into account the potential operating problems that can occur with using SCR in the oil firing mode.

A concern associated with the use of SCR on combined cycle projects is the formation of ammonium bisulfate. For the SCR process, ammonium bisulfate can be formed due to the reaction of sulfur in the fuel and the ammonia injected. The ammonium bisulfate formed has a tendency to plug the tubes of the HRSG, thus leading to operational problems. As this is the case, SCR has been judged to be technically infeasible for oil firing in some previous BACT determinations.

The latest information available now indicates that SCR can be used for oil firing provided that adjustments are made in the ammonia to NO_X injection ratio. For natural gas firing operation, NO_X emissions can be controlled with up to a 90 percent efficiency using a 1 to 1 or greater ammonia injection ratio. By lowering the injection ratio for oil firing, testing has indicated that NO_X can be controlled with efficiencies ranging from 60 to approximately 75 percent. When the injection ratio is lowered, there is not a problem with ammonium bisulfate formation since essentially all of the ammonia is able to react with the NO_X present in the combustion gases. Furthermore, by using low sulfur fuel oil with low metal content and limiting excess air, the amount of sulfur trioxide available to form ammonium bisulfate is minimized. Based on this strategy SCR has been both proposed and established as BACT for oil fired combined cycle facilities with NO_X emission limits ranging from 11.7 to 25 ppmvd depending on the efficiency of control established.

The applicant has indicated that the total levelized annual operating cost to install SCR for this project at 100 percent capacity factor and burning natural gas is $4,462,200. Taking into consideration the total annual cost, a cost/benefit analysis of using SCR can now be developed.

For the Westinghouse 501F combined cycle CT and based on the information supplied by the applicant, it is estimated that the maximum annual NO_x emissions using dry low-NO_x combustors will be 1,205 tons/year (assuming 7,260 and 1,500 hours of operation per year while firing natural gas and fuel oil, respectively, including 2,000 hours with power augmentation on natural gas). Assuming that SCR would reduce the NO_x emissions from 15 ppmvd to 9 ppmvd when firing natural gas and from 25 ppmvd to 9 ppmvd during power augmentation mode, and from 42 ppmvd to 15 ppmvd when firing fuel oil, 549 tons of NO_x would be emitted annually. When this reduction of 656 TPY is compared with the application of dry low-NOx combustors and considering the total levelized annual operating cost differential to be $4,462,200, the cost per ton of controlling NO_x is $6,802. These calculated costs are higher than has previously been approved as BACT.

A review of the latest Department BACT determinations show limits of 15 ppmvd (natural gas) using low-NO_x combustor technology for combined cycle CTs. Combustion turbine manufacturers are currently developing programs using both steam/water injection and dry low-NO_x combustor technology to achieve a NO_x emission control level of 9 ppmvd when firing natural gas.

Sulfur Dioxide (SO_2)

The applicant has stated that SO_2 emissions will be controlled by using fuel oil with a maximum sulfur content of 0.05%, by weight. This will result in an annual emissions rate of 140 TPY of SO_2 (each CT operating at 1,500 hours per year on fuel oil) plus 35 TPY of SO_2 when firing natural gas.

In accordance with the "top down" BACT review approach, only two alternatives exist that would result in lower SO_2 emissions. These include the use of a lower sulfur content fuel oil or the use of wet lime injection 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 emissions from stationary gas turbines is considered unreasonable." EPA reinforced this point when, later on 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 would be 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 then leaves the use of low sulfur fuel oil as the next option to be investigated. The use of No. 2 fuel oil with a maximum sulfur content limit of 0.05%, by weight, as proposed by the applicant, is acceptable as BACT for this project.

BACT Determination by the Department

Combined Cycle CTs

NO_X Control

The information that the applicant presented indicates that the cost per ton of controlling NO_X for these turbines is $6,802, which is significantly higher when compared with other BACT determinations that require SCR. Operational experience of utilities elsewhere indicates that catalysts are lasting longer than expected. Therefore the Department believes the costs are somewhat lower. Based on the information presented by the applicant, the Department accepts the applicants conclusion that the use of SCR for NO_X control is not justifiable as BACT at this time.

A review of the permitting activities for combined cycle proposals across the nation indicates that SCR has been required and most recently proposed for installations with a variety of operating conditions (i.e., natural gas, fuel oil, coal and various capacity factors). The cost and other concerns expressed by the applicant are accepted and the Department determines that water injection and dry low-NO_X burner design as BACT for NO_X for this project for fuel oil and natural gas, respectively.

The applicant has proposed a NO_X emission limit of 104 lbs/hr/CT (15 ppmvd for natural gas) without power augmentation. CT manufacturers are currently offering NO_X guarantees of approximately 9 ppmvd. However, these CT manufacturers have no commercial operating experience to validate this guarantee basis. Considering the uncertainty regarding the basis of CT manufacturer's guarantees and the lack of commercial operating experience at this lower emission level, the Department has determined that a NO_x emission limit of 15 ppmvd @ 15% O_2 (104 lbs/hr/CT) for continuous compliance [1-hour average, not corrected to ISO conditions], is required. 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 those prior BACT determinations, no a nitrogen or for power augmentation operation. Measured NO_x concentrations shall not be corrected to ISO conditions to determine compliance with these BACT standards. Based on the first 12 months of actual operating data using natural gas, the Department may seek to revise and lower the NO_x emissions standard from 15 ppmvd @ 15% O_2 to no lower than 9 ppmvd @ 15% O_2; again, the NO_x emissions standard will not be ISO corrected.

SO_2 Control

BACT for SO_2 is the burning of No. 2 fuel oil with a maximum sulfur content limit of 0.05%, by weight. The Department accepts the applicant's proposal as BACT for this project.

VOC and CO Control

The Department is in agreement with the applicant's proposal of good combustion and operating practices as BACT for CO and VOCs for this project.

Other Emissions Control

The emission limitations for PM/PM_{10}, Visible Emissions, Be, and As are based on previous BACT determinations for similar facilities. Although the emissions of these pollutants could be controlled by particulate matter control devices, such as a baghouse or scrubber, the amount of emission reductions would not warrant the added expense. The Department accepts the applicant's proposed strategy of requiring good quality fuel for controlling these pollutants as BACT for the two combined cycle CT units.

The BACT emission limits for the Hardee Unit 3 project of two CTs for generating 300 MW and a single 140 MW steam turbine are as follows:

440 MW TOTAL COMBINED CYCLE COMBUSTION TURBINES

Pollutant	Emission Standards/Limitations Oil(a)	Gas(b)	Method of Control
NO_x	42 ppmvd @ 15% O_2	15 ppmvd(c) @ 15% O_2	Water Injection on oil; Dry Low-NO_x Combustor on gas

CO	25 ppmvd	20 ppmvd	Combustion controls; Limited Fuel Oil Operation
PM & PM_{10}	67 lbs/hr	7 lbs/hr	Combustion controls; Limited Fuel Oil Operation
Visible Emissions	≤ 10% Opacity ≤ 10% Opacity		Natural Gas No. 2 Fuel Oil
SO_2	0.05% S	1 gr S/100 scf	No. 2 Fuel Oil (max. 0.05% sulfur content limit, by weight)
VOC	10 ppmvd	5 ppmvd	Combustion controls
Be	--	--	Fuel Quality
As	--	--	Fuel Quality
Benzene	--	--	Fuel Quality

(a) No. 2 fuel oil with a maximum limit of 0.05% sulfur content, by weight. Fuel oil firing shall not exceed an equivalent of 1,500 hours per year per CT at full load (not to exceed 3,000 hrs/yr between the two CTs).
(b) Natural gas firing of up to 8,760 hours per year.
(c) Interim limit. May be retained or lowered (as low as 9 ppmvd at 15% O_2) based on the results of a study of the first 12 months of commercial operation.

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

Syed Arif, Permit Engineer
Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Recommended by:

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

_______________________ 1995
Date

Approved by:

____
Virginia B. Wetherell, Secretary
Dept. of Environmental Protection

_______________________ 1995
Date

Attachments 1 - 3

Available Upon Request

ATTACHMENT 4

SEMINOLE ELECTRIC COOPERATIVE INCORPORATED

OVERNIGHT

RECEIVED

FEB 10 1995

Bureau of
Air Regulation

February 9, 1995

Bruce Mitchell
Bureau of Air Regulation
Department of Environmental Protection
Magnolia Courtyard
111 So. Magnolia
Tallahassee, FL 32399

Re: Seminole Electric Coop. Inc.; Hardee Unit 3 - Proposed BACT and Permit Conditions

Dear Bruce:

Seminole Electric Cooperative, Inc. (Seminole) appreciated the opportunity to meet with you and Syed Arif to discuss the Bureau's draft BACT analysis and proposed conditions of certification for Seminole's Hardee Unit 3 project. As we discussed in our meeting on January 31, 1995, the two principal issues associated with the permits for this project are the request for higher emission rates for nitrogen oxides (NO_x) and carbon monoxide (CO) during periods of steam augmentation and an increase in NO_x emissions based upon the fuel bound nitrogen content of the low sulfur fuel oil delivered to the project. As explained below, Seminole believes that these requests are justified and consistent with the objective of achieving the lowest emissions from this project, while considering economic and environmental issues.

The Hardee Unit 3 project is a 440 megawatt facility. It will be comprised of 2 150-megawatt Westinghouse 501F combustion turbines, with each CT connected to a single heat recovery steam generator (HRSG). The electrical output from this Seminole-owned facility will replace electricity Seminole currently purchases from other Florida utilities. The project will therefore supply existing demand for electricity by the members of Seminole's 11 electrical cooperatives in Florida. Unlike many recently permitted projects, the Hardee Unit 3 project is not being undertaken to meet future growth and demand. The demand exists today and will continue to exist at a level of 440 megawatts on the planned in-service date of January 1, 1999. The proposed project with the Westinghouse CTs has therefore been sized to best meet this 440 megawatt demand.

Steam Augmentation

As Westinghouse representatives explained in our meeting, during those times when the ambient temperature is above approximately 80°F, the electrical output of the combustion turbines during natural gas firing drops due to the decreased density of the air which is forced through the CT. High ambient temperatures cause the air to expand beyond the abilities of the CT's compressors and evaporative chillers to maintain a minimum air density passing through the CT to achieve the 440 megawatt output.

To compensate for the reduced power output during hot, humid days, high pressure steam must be injected into the combustor, mixing with the high pressure air from the CT compressor, to increase the mass flow through the CT. However, the moisture content of the injected steam affects the stability of the combustor pilot flame. To maintain flame stability, additional fuel is fed to the combustor pilot, resulting in an increase in NO_x emissions. The presence of moisture from the steam also causes carbon monoxide to increase to 50ppm levels.

With dry low NO_x combustors operating on natural gas fuel, the NO_x formed in the combustion process is minimized by designing the combustors to operate at very lean fuel to air ratios, an inherently less stable combustion point than occurs in conventional combustors. Thus, dry low NO_x combustors are less tolerant to the reduction in flame stability caused by steam injection. Power or steam augmentation is achieved differently than with conventional combustors by injecting the steam into the combustor casing rather than directly into the combustor. This form of injection disseminates the steam throughout the internal passages rather than focusing it on the flame, although much of the steam still enters the flame zone. Since the thermal NO_x levels are already so low in these DLN designs, there is not a significant further reduction in NO_x from the steam. In the Westinghouse DLN combustor, a central pilot is used in the design to add stability to the lean premix regions of the combustor. The central pilot operates similar to a conventional combustor and thus impacts the NO_x level of the combustor. As steam augmentation is brought on, the percentage of the total fuel that is injected through the central pilot is increased, thus increasing the NO_x levels from the CT from 15ppm to 25ppm.

While steam augmentation increases NO_x emissions, Seminole believes that this is the most acceptable alternative available to provide the needed 440 megawatts of output, considering both environmental and economic factors. Westinghouse and other CT manufacturers do not have CTs that are incrementally larger in output to provide the needed power during these meteorological conditions. Combustion turbines come in standard megawatt capacities or classes and CT manufacturers therefore are unable to exactly size a CT to a given utility's needs in many circumstances.

The other alternatives available to Seminole to meet its 440 megawatt need in these circumstances include installing a stand-alone 20 to 25 megawatt CT to provide the power during the identified meteorological conditions or to purchase power from another utility. As indicated in the analysis by Ken Kosky of KBN, a simple cycle 25 megawatt CT would cost approximately $15.8 million, with an annualized incremental operating cost of $1,993,320 for both capital and fuel costs. Assuming this standalone CT also achieved an emission rate of 15ppm, the cost effectiveness of removing the incremental 83.3 tons of NO_x by installing a small CT would be $23,930 per ton of NO_x removed. This cost effectiveness value greatly exceeds the value the Department has previously established for NO_x removal.

The second alternative available to Seminole to provide the incremental 20 megawatts would involve contracting with another Florida utility to provide power during these periods. Since all other baseload units with relatively low NO_x rates would already be on line when ambient temperatures reach 80°F and greater, it is most likely that the incremental power Seminole needs would be generated from an existing power plant at a much greater NO_x emission rate. Seminole expects that it would cost Seminole $2.8 million per year to contract with another utility (most likely TECO Energy) to provide this incremental power. With the Hardee Unit 3 operating with steam augmentation, total annual emissions are expected to be 212 tons per year. However, if Hardee Unit 3 is denied steam augmentation and replacement power must be purchased by Seminole from another existing plant, Seminole estimates that total NO_x from the Hardee Unit 3 and the other plant would be at least 226 tons per year. Thus, without steam augmentation, NO_x emissions would <u>increase</u> by 14 tons per year while costing Seminole at least $2.8 million. Thus, Seminole would be forced to pay more money to meet its 440 megawatts of need, while increasing total NO_x emissions when compared to the steam augmentation scenario.

Thus, Seminole believes that the PSD permit and conditions of certification should authorize use of steam augmentation at emission rates of 25ppm for NO_x and 50ppm for CO during natural gas firing of the Hardee Unit 3 during those periods when ambient temperatures exceed 80°F, which is estimated to occur 2,000 hours per year.

<u>Fuel Bound Nitrogen</u>

Based upon the information provided by Westinghouse, Seminole continues in its request that it be granted up to an additional 12ppm for NO_x emissions based on the nitrogen content of the fuel oil delivered to the project. Westinghouse has optimized the new dry low NO_x combustors on the large F class CTs to produce the lowest NO_x levels attainable on natural gas, while still maintaining oil firing capability. In order to achieve low NO_x emissions during natural gas firing, the DLN design limits the options for water injection during oil firing and therefore, the ability to achieve lower NO_x levels. Westinghouse has therefore based its guaranteed NO_x rate of 42ppm during oil firing upon a maximum fuel bound nitrogen content of 0.15% nitrogen.

DLN combustors can only control formation of thermal NO_x; fuel bound nitrogen (FBN) is not subject to combustion controls and is, therefore, "passed" through the machine. To meet the proposed 42ppm NO_x level for fuels with an FBN above 0.015% in fuel oil, the unit operator would be forced to over-control thermal NO_x by adding additional water injection during oil firing. While this may be achievable with conventional combustors or with single fuel (oil only) combustors on smaller CTs, Westinghouse does not believe that can be accomplished with the planned DLN combustor for this F class machine. The DLN is not expected to have any margin in the NO_x rate during oil firing that could be used to buffer the fuel bound nitrogen present in oil. Westinghouse is concerned that to attempt to inject additional water will create stress on the CT components and reduce unit efficiency by increasing the heat rate. Also, operating data during tests on CTs suggest that increasing water injection beyond a water to fuel ratio of 1.0 does not substantially reduce thermal NO_x formation but may significantly increase CO emissions well above proposed allowable levels.

Fuel bound nitrogen is solely a function of the oil refining and supply process. Seminole's investigation indicates that oil refiners are not refining or controlling for nitrogen content in fuel oil. While it appears that lower sulfur fuels (i.e., 0.05% sulfur oil) also have lower nitrogen contents as well, about 25% of the reported samples in one survey indicated that nitrogen content in low sulfur fuel oil still exceeded the threshold of 0.015% nitrogen. Thus, the oil refining industry does not currently continuously produce a low nitrogen/low sulfur fuel oil that would allow Seminole to meet the Department' proposed NO_x level of 42ppm.

Only one fuel oil supplier responded to Seminole's inquiry concerning a guaranteed price for fuel with a specified nitrogen content of no greater than 0.015% nitrogen. That single bidder would charge Seminole an additional 2.27¢ per gallon of fuel oil to supply low sulfur fuel with a nitrogen content of 0.015% or less. Based upon this price premium to Seminole, and assuming a maximum 0.03% nitrogen in the fuel (and an additional 12ppm of NO_x emissions for a total of 54ppm during oil firing) the cost effectiveness of payment of this premium to achieve the Department's proposed 42ppm emission rate would be a minimum of $6,737 per ton of NO_x removed. For fuel oil with a lower FBN content, the cost effectiveness on a per ton removal basis, would be even greater. Therefore, Seminole believes that requiring use of a low nitrogen fuel, which is the effect of the Department's proposed permit limit, is not cost effective and is unnecessary since the average nitrogen content of fuel oil would likely be at or below 0.015% nitrogen in most cases.

Attached for your further reference are the overheads used by Westinghouse and KBN in their presentation at our recent meeting. These are provided to further support Seminole's request for a differential NO_x emission rate during steam augmentation operation and for a fuel bound nitrogen allowance of up to 12ppm. While we hope that this information is useful to the Department in evaluating this request, if there is further information that you need, we are available to provide that information to you. Again, your attention to this request is appreciated.

Sincerely,

Kenneth L. Bachor

Kenneth L. Bachor
Manager, Environmental Licensing

KLB:jwl
Attachment
cc: w/o attachments
Syed Arif, BAR
Steve Palmer, Office of Siting Coordination
Richard Donelan, Office of General Counsel