Florida Department of Environmental Regulation

Twin Towers Office Bldg. • 2600 Blair Stone Road • Tallahassee, Florida 32399-2400

Bob Martinez, Governor | Dale Twachtmann, Secretary | John Shearer, Assistant Secretary

December 5, 1990

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Ms. Jewell A. Harper
Air Enforcement Branch
U.S. EPA, Region IV
345 Courtland Street, N.E.
Atlanta, Georgia 30365

Dear Ms. Harper:

Re: TECO/Seminole Electric - Hardee Power Station
Federal Number: PSD-FL-140

Enclosed for your review and comment is a copy of the Technical Evaluation and Preliminary Determination for the above referenced project. Please submit any comments or questions to Tom Rogers or Barry Andrews at the above address or call them at 904-488-1344 at your earliest convenience.

Sincerely,

Barry D. Andrews

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

CHF/BA/plm

Enclosure

cc: D. Thomas, SW Dist.
Holland & Knight

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NOTICE OF CERTIFICATION HEARING ON AN APPLICATION TO CONSTRUCT AND OPERATE AN ELECTRICAL POWER PLANT TO BE LOCATED NEAR WAUCHULA, FLORIDA

1. Application number PA 89-25 for certification to authorize construction and operation of an electrical power plant near Wauchula, Florida, associated transmission lines from the Hardee Power Station site to Tampa Electric Company's Pebbledale Substation, to Florida Power Corporation's Vandolah substation, and Lee County Cooperative's Lee substation, and a natural gas pipeline from the site to Florida Gas's pipeline near Polk City, is now pending before the Department of Environmental Regulation, pursuant to the Florida Electrical Power Plant Siting Act, Part II, Chapter 403, F.S. Certification of this power plant would allow construction and operation of a new source of air pollution which would consume an increment or air quality resources. The department review has resulted in an assessment of the prevention of significant deterioration impacts and a determination of Best Available Control Technology necessary to control the emission of air pollutants from this source.

2. The proposed 1259 acre power plant site is located partly in the northwestern portion of Hardee County and partly in southwestern Polk County. The site is approximately seven and one-half miles west of Bowling Green and ten miles northwest of Wauchula. The unincorporated community of Fort Green Springs is located 2.5 miles to the south. The site will house combined cycle combustion turbines, heat recovery steam generators, electrical generators and a large cooling pond. The ultimate capacity of the site is proposed to be 660 megawatts. Associated linear facilities include three 230 kV transmission lines will connect the facility to existing Tampa Electric Company, Florida Power Corporation, and Florida Power and Light Company substations. Also, a natural gas pipeline will be constructed to the site from an existing gas pipeline north of Polk City.

3. The Department of Environmental Regulation has evaluated the application for the proposed power plant. Certification of the plant would allow its construction and operation. The application and the department's evaluation is available for public inspection at the addresses listed below:

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL REGULATION
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL REGULATION
Southwest District Office
4520 Live Oak Fair Boulevard
Tampa, Florida

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL REGULATION
South Florida District Office
2269 Bay Street
Ft. Myers, Florida

Bartow Public Library
315 E. Parker St.
Bartow, FL 33830

Lee County/Ft. Myers Public Library
2050 Lee St.
Ft. Myers, FL 33901

Desoto County Library
519 Hickory St.
Arcadia, FL 33821

Hardee County Library
315 N. 6th Ave. Suite 114
Wauchula, FL 33873

The business address of the co-applicants for the project are as follows:

Seminole Electric Cooperative, Inc.
1613 North Dale Mabry Highway
Tampa, Florida 33614

TECO Power Services Corporation
Tampa Electric Company
702 North Franklin Street
Tampa, Florida 33602

4. Pursuant to Section 403.508, Florida Statutes, the certification hearing will be held by the Division of Administrative Hearings beginning on July 30, 1990, at 11:00 a.m., at the American Legion Post #2, 25 West Palmetto Street, Wauchula, Florida, on July 31, at 9:00 a.m., at the Hardee County Courthouse, County Commission Meeting Room, 412 West Orange Street, Wauchula, and on August 1, 9:00 a.m., American Legion Post #2, Wauchula, Florida, in order to take written and oral testimony on the effects of the proposed power plant or any other matter appropriate to the consideration of the site. Need for the facility has been predetermined by the Public Service Commission at a separate hearing.

5. When appropriate, any person may be given an opportunity to present oral or written communications to the designated hearing officer. If the designated hearing officer proposes to consider such communication, then all parties shall be given an opportunity to cross-examine or challenge or rebut such communications.

6. Notices or petitions made prior to the hearing should be made in writing to:

Mr. Donald D. Conn
Division of Administrative Hearings
The Desoto Building
1230 Apalachee Parkway
Tallahassee, Florida 32399-1550

Copies of such submittals should be forwarded by mail to existing parties, including the Department of Environmental Regulation.

7. Those wishing to intervene in these proceedings, unless appearing on their own behalf, must be represented by an attorney or other person who can be determined to be qualified to appear in administrative hearings pursuant to Chapter 120, F.S., or Chapter 17-103.020, F.A.C.

8. On June 30, 1989, TECO Power Services , Tampa Electric Company and Seminole Electric Cooperative, Inc. applied to the DER to construct the aforementioned power plant. The application is also subject to U.S. Environmental Protection Agency (EPA) regulations for Prevention of Significant Deterioration of air quality (PSD), codified at 40 CFR 52.21, and Florida Administrative Code Chapter 17-2.04. These regulations require that, before construction on a source of air pollution subject to PSD may begin, a permit must be obtained from DER Such permit can only be issued if the new construction has been determined by DER to comply with the requirements of the PSD regulations, which are described in 40 CFR 52.21 and 17-2.04, F.A.C. These requirements include a restriction on incremental increases in air quality due to the new source and application of best available control technology (BACT).

The DER has been granted a delegation by EPA to carry out the PSD review of this source. Acting under that delegation, the DER has prepared a draft permit which is included in the DER's staff analysis report. The DER has made a preliminary determination that the proposed construction will comply with all applicable PSD regulations. The degree of Class II increment consumption that will result from the construction is:

Pollutant	Annual Average	24-hr Average	3-hr Average
Particulate	4.7%	21.6%	--
Sulfur Dioxide	41.5%	72.5%	82.8%
Nitrogen Dioxide	23.6%	--	--

The source is located more than 100 kilometers from the nearest Class I area.

Construction and operation of the source will not cause a violation of any ambient air quality standard nor will it cause an exceedance of any PSD increment.

9. This Public Notice is also provided in compliance with the Federal Coastal Zone Management Act, as specified in 15 CFR Part 930, Subpart D. Public comments on the applicant's federal consistency certification should be directed to the Federal Consistency Coordinator, Division of Environmental Permitting, Department of Environmental Regulation.

10. Pursuant to Section 403.509 (2), F.S. Tampa Electric Company or Seminole Electric Cooperative, Inc. intends to use, connect to or cross over properties of the Florida Game and Fresh Water Fish Commission, Florida Department of Transportation and Trustees of the Internal Improvement Trust Fund.

11. Pursuant to Section 403.511 (2), F.S. Teco Power Services, and Seminole Electric Cooperative, Inc. seek a variance from Section 16C-16.0051, F.A.C., Department of Natural Resources for the purposes of constructing a cooling reservoir on mined lands subject to reclamation.

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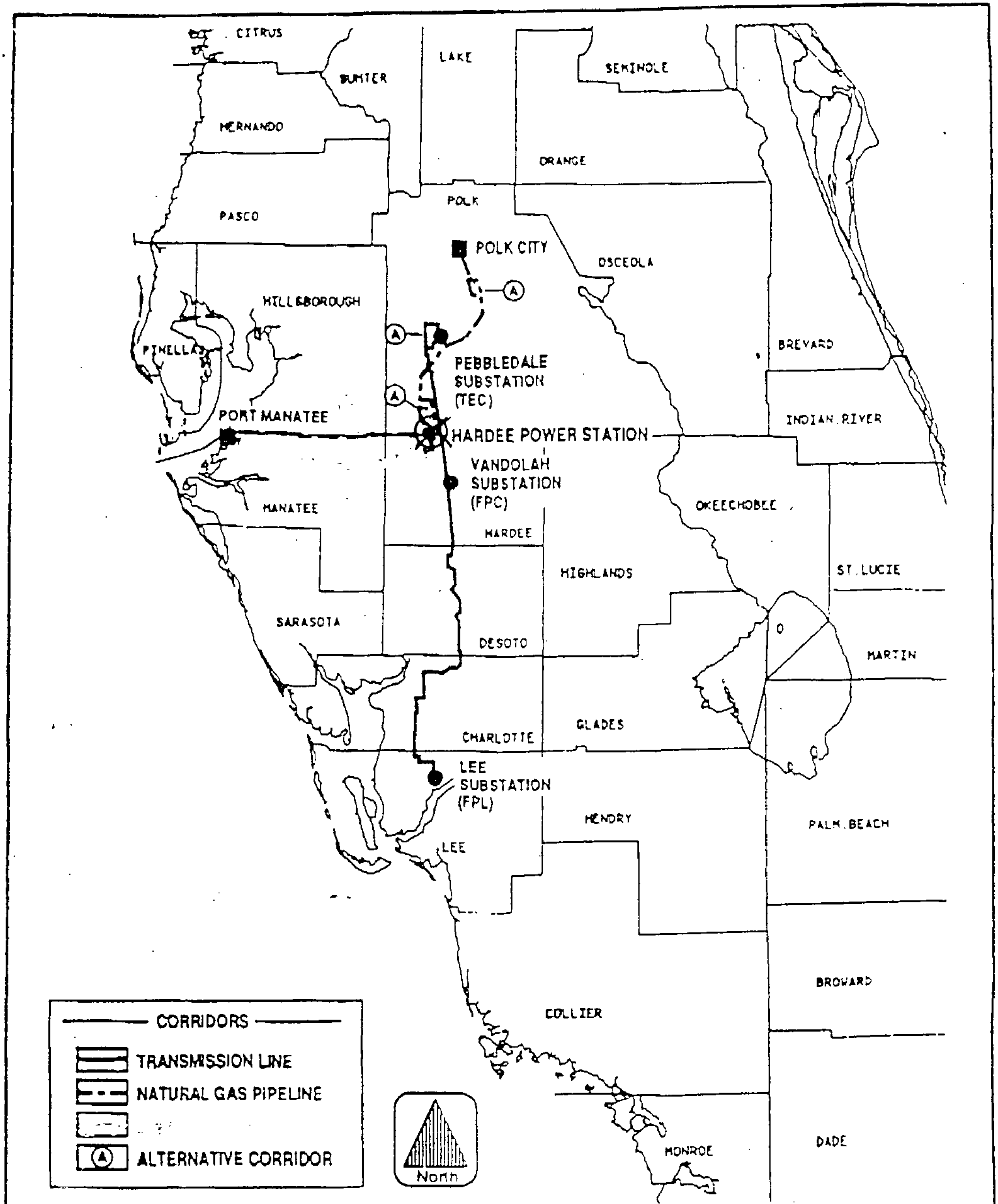
Technical Evaluation
and
Preliminary Determination

TECO/Seminole Electric - Hardee Power Station
Hardee/Polk County, Florida

Permit No. PSD-FL-140

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

August 10, 1990



HARDEE POWER STATION AND ASSOCIATED FACILITIES

TECO POWER SERVICES

TAMPA ELECTRIC COMPANY

SEMINOLE ELECTRIC COOPERATIVE, INC.

State of Florida Department of Environmental Regulation
TECO Power Services/Seminole Electric Cooperative, Inc.
Tampa Electric Company
Hardee Power Station
Electric Power Plant Site Certification Review Case No. PA 89-25

I. SUMMARY

Facilities Overview

TECO Power Services, Inc, (TPS) Tampa Electric Company (TECO) in partnership with Seminole Electric Cooperative, Inc. (SECI) proposes to certify a power plant site that will ultimately house a 660 megawatt (MW), gas fired power plant. The first phase of the project will be a 295 MW combination of combustion turbines coupled with heat recovery steam generators. The generating plant will be constructed on property now owned by Agrico as part of their phosphate mining operations. The project is known as the Hardee Power Station. The generating units would be tied into the TECO, Florida Power Corporation (FPC) and Lee County Cooperative electric power networks via new transmission lines. Three 230 KV lines will be necessary to transmit the power from the plant to existing TECO, FPC, and Lee County Cooporative substations. Fuel delivery for the combustion turbines will be by natural gas pipeline from the Florida Gas Transmission System pipeline north of Polk City. A back up fuel supply of light oil will be trucked to the site.

Approximately 1300 acres of land would be required for the operation of the Hardee Station. This would be due to in part to the need for constructing a 570 acre cooling reservoir on mined over phosphate land. Land space is also being reserved in the event that coal gasification might become economically feasible in the future.

The Hardee Station will utilize a fresh water cooling reservoir with only emergency overflow discharge to Payne Creek during periods of high rainfall. Plant service water and cooling water would come from wells into the Floridian Aquifer. Rainfall will be a supplementary source of cooling water. Plant wastewaters would be pumped to wastewater treatment units with ultimate disposal to the cooling reservoir.

Air Impacts

Based on the proposed air pollutant control technologies, it is expected that the Hardee Power Station and associated facilities will use the best available control systems. Analysis of the predicted effects of plant emission indicates that no significant air quality impacts should occur.

Besides the biota already discussed in previous paragraphs, other species which are considered endangered or threatened at the site or transmission line corridors include the American alligator, the gopher tortoise, Florida gopher frog, the eastern indigo snake, wood stork, red cockaded woodpecker, and bald eagle.

The Florida Gopher Tortoise is a species of unique ecological value since Gopher Tortoise burrows provide a habitat for no less than 30 animal species, some of which can live nowhere else. Among these commensals inhabiting the dens are the Florida Gopher Frog (RARE), that emerges from these burrows only at night. No data is available on the number of these snakes living in gopher tortoise burrows at the HPS or corridors.

VI. FACILITY SPECIFIC CONCERNS

A. Air quality

1. Selected Fuel

The primary fuel for the HPS is natural gas. Light oil will be used as a backup fuel. Provisions are being made to leave room on site for a coal gasification unit as a future source of fuel.

2. Air Quality Impact Analysis

The proposed Hardee Power Station, located in northwest Hardee County, will emit in PSD-significant amounts nine pollutants. These pollutants include the criteria pollutants carbon monoxide (CO), nitrogen dioxide (NO_2), ozone (O3) (of which volatile organic compounds (VOC) are the regulated pollutant), particulate matter (PM and PM_{10}), and sulfur dioxide (SO_2), and the non-criteria pollutants beryllium (Be), mercury (Hg), and sulfuric acid mist.

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

* An analysis of existing air quality;
* A PSD increment analysis (NO2, PM and SO2 only);
* An Ambient Air Quality Standards (AAQS) analysis;
* An analysis of impacts on soils, vegetation, and visibility and of growth-related air quality 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 AAQS analysis depends on the air quality dispersion modeling carried out in accordance with EPA guidelines.

Based on the required analyses, the Department has reasonable assurance that the proposed sources at the Hardee Power Station, as described in this report and subject to the conditions of approval proposed herein, will not cause or contribute to a violation of any ambient air quality standard or PSD increment. A discussion of the modeling methodology and required analysis follows.

Modeling Methodology

For the screening modeling analysis, model results were calculated for a range of operating conditions for which the maximum ground-level impacts would be expected to occur. These operating conditions were based on either the facility's maximum emissions or on its minimum flow rate. The maximum predicted concentrations occurred when the minimum flow rate operating condition was modeled.

The EPA-approved Industrial Source Complex Short-Term (ISCST) dispersion model was used in the air quality impact analysis. This 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 and transformation. The ISCST 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.

The modeling used a radial receptor grid with the center of the grid coinciding with the center of the proposed facility. Radials were spaced at 10 degree increments from 10 to 360 degrees. The grid for the near-field receptors consisted of 308 receptors located at distances of 600, 900, 1250, 2250, 2750, 3500, 4500, and 6000 meters. For the directions of 10 through 160 degrees, receptors at a downwind distance of 600 meters from the proposed facility were not included in the modeling analysis because these receptors are on plant property. The grid for the plant property consisted of 36 discrete receptors.

After the screening modeling was completed, refined short-term modeling was conducted using a receptor grid centered on the receptor which had the highest, second-highest short-term concentrations. The receptors were located at intervals of 100 meters between the distances considered in the screening phase along nine radials, at two degree increments, centered on the radial which produced the maximum concentration.
Meteorological data used in the modeling consisted of five years (1982-1986) of hourly surface data taken at Tampa, Florida. Mixing heights used in the modeling were based on upper air data from Ruskin (near Tampa), Florida.

Table 1 lists the significant and net emission rates for the proposed facility. Table 2 lists the stack parameters for the proposed facility for the operating condition that produced the highest ground-level concentrations. Table 2 also lists the SO2 emission rate which produced the maximum predicted ground-level SO2 concentrations. It should be noted that the modeled SO2 emissions were specific for each operating condition because the maximum predicted SO2 concentrations were relatively high when compared to PSD Class II increments. For the other pollutants, the emissions from Case 1, which had the highest emissions among the cases, were modeled for all four operating cases; therefore, the maximum impacts predicted for cases 2 through 4 are conservative (lower impacts would be predicted if the emissions associated with each case were modeled). The emission rates for the other modeled pollutants are presented in the original application.

Table 1. Significant and Net Emission Rates (Tons per Year)

Pollutant	Significant Emission Rate	Existing Emissions	Proposed Maximum Emissions	Net Emissions	Applicable Pollutant (Yes/No)
CO	100	0	2810	2810	Yes
NO2	40	0	8405	8405	Yes
SO2	40	0	16083	16083	Yes
PM	25	0	1250	1250	Yes
PM10	15	0	1250	1250	Yes
VOC	40	0	450	450	Yes
Lead	0.6	0	0.25	0.25	No
Be	0.0004	0	0.072	0.072	Yes
Hg	0.1	0	0.32	0.32	Yes
Fluoride	1.0	0	0.93	0.93	No
Sulfuric Acid Mst	7	0	738	738	Yes

Table 2. Stack Parameters for Proposed SO2 Sources.

Source	Emission Rate (g/s)	Height (m)	Exit Temp (K)	Exit Vel (m/s)	Diameter (m)
Facility	345	23	389	16.5	4.9

The Hardee facility was modeled as three identical units separated by 100 meters in a north-south line. The emission rate presented in Table 2 is the total emission of SO2 from the facility.

Analysis of Existing Air Quality

Preconstruction ambient air quality monitoring is required for all pollutants subject to PSD review. In general, one year of quality assured data using an EPA reference, or the equivalent monitor must be submitted. Sometimes less than one year of data, but no less than four months, may be accepted when Departmental approval is given.

An exemption to the monitoring requirement can be obtained if the maximum air quality impact, as determined by air quality modeling, is less than a pollutant-specific "de minimus" concentration. In addition, if current monitoring data exists and these data are representative of the proposed source area, then at the discretion of the Department these data may be used.

The predicted ambient impact of the proposed facility for those pollutants subject to PSD review are listed in Table 3. Sulfuric acid mist is not listed because there is no de minimus level for this pollutant. However, an estimate of sulfuric acid mist ground-level concentrations can be obtained from modeling performed on SO2. Sulfuric acid mist is emitted at 738 TPY as compared to 16,083 TPY for SO2. The maximum predicted SO2 concentration is multiplied by this ratio (738/16083) to estimate the maximum ground-level concentration of sulfuric acid mist. A maximum 24- hour concentration of 2.9 ug/m3 is predicted for sulfuric acid mist. This value is much less than the acceptable ambient concentration of 4.76 ug/m3, as defined by the Department. Consequently, monitoring for this pollutant is not required.

The predicted maximum impact for CO, NO_2, PM, PM_{10}, Be, and Hg is less than their respective de minimus impact levels. Therefore, no additional monitoring is required for these pollutants.

The predicted maximum impact for SO_2 is greater than the appropriate de minimus value. The applicant obtained ambient SO_2 monitoring data from the Department for a monitoring station located about 25 km north-northwest of the proposed facility. Because this monitor is located in an urban area and/or in proximity of major sources, the observed concentrations are considered to be higher than those likely to occur at the proposed facility. A more detailed discussion about the monitoring data collected is presented in the section entitled "AAQS Analysis" of this report.

A preconstruction monitoring review is required for ozone concentrations because the maximum potential VOC emissions from the proposed plant are greater than 100 TPY. The proposed facility is located in an ozone attainment area. The proposed site is in a rural area with minimal industrial development (i.e., lack of major VOC emission sources) within 15 km of the site. Consequently, the Department did not require preconstruction monitoring for ozone.

Table 3. Maximum Air Quality Impacts for Comparison to the Significant Impact and De Minimus Ambient Levels.

Pollutant	Avg. Time	Predicted Impact (ug/m3)	Sign. Impact Level (ug/m3)	De Minimus Level (ug/m3)
CO	1-hour	179	2000.0	N/A
	8-hour	38.0	500.0	575.0
NO2	Annual	4.6	1.0	14.0
PM	24-hour	7.5	5.0	10.0
	Annual	0.8	1.0	N/A
PM10	24-hour	7.5	5.0	10.0
	Annual	0.8	1.0	N/A
SO2	3-hour	424	25.0	N/A
	24-hour	62.5	5.0	13.0
	Annual	6.7	1.0	N/A
Be	24-hour	0.0004	N/A	0.0005
Hg	24-hour	0.0016	N/A	0.25
VOC	TPY	450 TPY	N/A	100 TPY

3. Prevention of Significant Deterioration

Pursuant to Chapter 17-2, F.A.C., and 40 CFR 52.21, the Hardee Power Project units are subject to a review for the Prevention of Significant Deterioration (PSD) of air quality. The Clean Air Act Amendments of 1977 prescribe incremental limitations on the air quality impacts of a new source. The Department of Environmental Regulation has reviewed the PSD analysis submitted by the applicants and has found that the construction of the facility is not expected to violate state PSD regulations as contained in Section 17-2.310, F.A.C.

Additionally, the Preliminary Determination for the Hardee Power Project was completed in March of 1990. Federal regulations on PSD (40 CFR 52.21) require the following air quality impacts to be addressed:

a. National Ambient Air Quality Standards (AAQS)
b. PSD increment impact
c. Visibility, soils and vegetation impacts
d. Impacts due to growth caused by the proposed source
e. Class I area impacts
f. GEP stack height determination
g. Best Available Control Technology (BACT)

After their review, DER has made a preliminary determination that the the ambient air quality standards will not be violated and that the construction can be approved provided certain conditions are met.

AAQS Analysis

Given existing air quality in the area of the proposed facility, emissions from the proposed facility are not expected to cause or contribute to a violation of an AAQS. The results of the AAQS analysis are summarized in Table 4.

Of the pollutants subject to review, only CO, NO_2, PM, PM_{10}, SO_2 and O_3 have an AAQS. Except for O_3, dispersion modeling was performed as detailed earlier for the proposed facility. The modeling results indicate that for CO the maximum predicted impacts were less than the significant impact levels defined in Rule 17- 2.100 (170), FAC. As such, no modeling of other sources was necessary for CO. The total CO impact was determined from the impact of proposed facility added to a background concentration of 21 ug/m3 (1-hour average) and 6 ug/m3 (8-hour average), the highest recorded values in Hillsborough County in 1988. These background estimates of the CO concentration are considered to be very conservative since the proposed facility's location is rural in nature and the monitored data were obtained from a heavily urbanized area. The total impact of the proposed impact, combined with this conservative background, is far below the respective AAQS's (Table 4).

For the remaining pollutants subject to 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 "background" concentrations are taken from areas that are much more industrialized than the proposed facility's location. Therefore, these background values are considered to be conservative. The location of the monitors used to define the background concentrations are detailed in the original application.

Table 4. Ambient Air Quality Impact

Pollutant and Averaging Time		Maximum Impact of Proposed Project (ug/m3)	Predicted Total Impact (ug/m3)	Florida AAQS (ug/m3)
CO	(1-hour)	178.5	199.5	40000
	(8-hour)	38.0	44.0	10000
NO_2	(Annual)	6.2	51.2	100
SO_2	(3-hour)	424.0	691.0	1300
	(24-hour)	118.0	169.0	260
	(Annual)	19.3	30.3	60
PM_{10}	(24-hour)	21.2	112.2	150
	(Annual)	3.6	48.6	60

There is currently no acceptable method to model ozone. Consequently, the control of the VOC emissions are addressed in BACT review.

PSD Increment Impact Analysis

The proposed facility is located in a Class II area. This area is also designated as an attainment area for NO_2, PM and SO_2. Therefore, a PSD increment analysis is required to show compliance with the Class II NO_2, PM and SO_2 increments.

The PSD increment represents the amount that new sources in an area may increase ambient ground-level concentrations of a pollutant. At no time, however, can the increased loading of a pollutant cause or contribute to a violation of the ambient air quality standard.

Atmospheric dispersion modeling, as previously described, was performed to quantify the amount of PSD increment consumed. The modeling results indicate the maximum NO_2 Class II increment consumed is 5.9 ug/m3, which is less than 25 percent of the allowable PSD NO_2 increment of 25 ug/m3, annual average.

The modeling results indicate the maximum PM Class II increment consumed is 8 ug/m3 for a 24-hour average and 0.9 ug/m3 for an annual average. These predicted impacts are much below the allowable increment values of 37 and 19 ug/m3, respectively.

Modeling results indicate the maximum SO_2 increment consumed is 424 ug/m3 for a three-hour average, 66 ug/m3 for a 24-hour average and 8.3 ug/m3 for an annual average. These predicted impacts are below the allowable increment values of 512, 91 and 20 ug/m3, respectively.

Impacts on Visibility, Soils and Vegetation

The maximum ground-level concentration predicted to occur for each pollutant as a result of the proposed project, including a background concentration, will be below the applicable AAQS including the national secondary standard developed to protect public welfare-related values. As such, this project is not expected to have a harmful impact on soils and vegetation.

A visibility analysis is not required since the proposed facility is not to located within 100 km of a Class I area.

Growth-Related Air Quality Impacts

The proposed facility is not expected to significantly change employment, population, housing or commercial/industrial development in the area to the extent that an air quality impact will result.

Class I Area Impacts

A Class I area increment analysis is not required because the facility is not located within 100 km of a designated Class I area.

GEP Stack Height Determination

Good Engineering Practice (GEP) stack height means the greater of: (1) 65 meters or (2) the maximum nearby building height plus 1.5 times the building height or width, whichever is less. The GEP stack height determination is dependent on the distance and orientation to the various buildings nearby the stack because the projected building width can change.

The applicant calculated the GEP heights for each proposed source based on the dimensions of nearby buildings. The greatest height for each of the sources was used for modeling purposes. The stack height used in the modeling was 22.9 meters, which is well below the GEP limit of 65 meters.

4. Best Available Control Technology

The applicant proposes to install a combined cycle power plant and directly associated facilities to be located on the border of Polk and Hardee County. The combined cycle facility will consist of combustion turbines, electric generators, and heat recovery steam generators (HRSG's).

Site certification is being sought for an ultimate capacity of 660 MW (nominal net); however, the facility will be constructed in 3 phases. Phase 1-A will consist of a nominal 220 MW combined cycle unit and a 75 MW stand-alone combustion turbine. Phase 1-B will add 145 MW of generating capacity through the addition of a combustion turbine, two HRSG's and one steam electric generator, resulting in two 220 MW combined cycle units. Phase 2 will consist of a third 220 MW unit to be added at an unspecified future date.

The combustion turbines will be capable of both combined cycle and simple cycle operation. It is anticipated that the combustion turbines will use natural gas as the primary fuel and distillate oil as the backup fuel. The applicant has indicated the maximum annual tonnage of regulated air pollutants emitted from the facility based on 100 percent capacity and oil firing at 32°F to be as follows:

Pollutant	Maximum Potential Emissions (tons/yr)	PSD Significant Emission Rate (tons/yr)
NOx	8,405	40
SO_2	16,083	40
PM	1,250	25

Pollutant	Maximum Potential Emissions (tons/yr)	PSD Significant Emission Rate (tons/yr)
PM_{10}	1,250	15
CO	2,810	100
VOC	450	40
H_2SO_4	738	7
Fluorides	0.93	3
Be	0.072	0.0004
Hg	0.32	0.1
Pb	0.25	0.6

Florida Administrative Code Rule 17-2.500(2)(f)(3) 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

July 5, 1989

BACT Determination Requested by the Applicant

Pollutant	Determination
NOx	42 ppmvd @ 15% O_2 (natural gas firing) 65 ppmvd @ 15% O_2 (diesel oil firing)
SO_2	Firing of natural gas or No. 2 fuel oil with an annual average sulfur content of 0.3% and a maximum sulfur content of 0.5%
PM and PM_{10}	5 lbs/hr (natural gas firing) 10 lbs/hr (diesel oil firing)
CO	10 ppmvd @ 15% O_2 (natural gas firing) 26 ppmvd @ 15% O_2 (diesel oil firing)
VOC	2 ppmvd @ 15% O_2 (natural gas firing) 5 ppmvd @ 15% O_2 (diesel oil firing)
H_2SO_4	Firing of natural gas and No. 2 fuel oil
Be	Firing of natural gas and No. 2 fuel oil
Hg	Firing of natural gas and No. 2 fuel oil

BACT Determination Procedure

In accordance with Florida Administrative Code Chapter 17-2, Air Pollution, this 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 Best Available Control Technology 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 (Particulates and Heavy Metals). Controlled generally by good combustion of clean fuels.

- Products of Incomplete Combustion (CO, VOC, Toxic Organic Compounds). Control is largely achieved by proper combustion techniques.

- Acid Gases (SOx, NOx, HCl, Fl). Controlled generally by gaseous control devices.

Grouping the pollutants in this manner facilitates the BACT analysis because it enables the equipment available to control the type or group of pollutants emitted and the corresponding energy, economic, and environmental impacts to be examined on a common basis. Although all of the pollutants addressed in the BACT analysis may be subject to a specific emission limiting standard as a result of PSD review, the control of "nonregulated" air pollutants is considered in imposing a more stringent BACT limit on a "regulated" pollutant (i.e., particulates, 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.

Combustion Products

The Hardee Power Station's projected emissions of particulate matter, PM_{10}, beryllium, and mercury exceed the significant emission rates given in Florida Administrative Code Rule 17-2.500, Table 500-2. A review of the BACT/LAER Clearinghouse indicates that the proposed PM/PM_{10} emission levels of 5 lbs/hr and 10 lbs/hr per turbine are consistant with previous BACT determinations for similar equipment firing natural gas and No. 2 fuel oil respectively. As this is the case, these emission limitations are reasonable as BACT for the Hardee Power Station.

In general, the BACT/LAER Clearinghouse does not contain specific emission limits for beryllium and mercury from turbines. BACT for heavy metals is typically represented by the level of particulate control. As this is the case, the emission factors of 5.0 and 10.0 lbs/hr per turbine for particulate matter/ PM_{10} when firing natural gas and No. 2 fuel oil, respectively, is judged to represent BACT for beryllium and mercury.

Products of Incomplete Combustion

The emissions of carbon monoxide, volatile organic compounds and other organics from combustion turbines are largely dependent upon the completeness of combustion and the type of fuel used. A review of the BACT/LAER Clearinghouse indicates that combustion turbines of similar size have CO and VOC limitations similar to the proposed levels of 10 ppmvd and 2 ppmvd, respectively, for natural gas firing. The proposed levels of 26 ppmvd and 5 ppmvd for CO and VOC, respectively, are also judged to be reasonable for oil firing. As this is the case, these emission limitations are reasonable as BACT for the Hardee Power Station.

Acid Gases

The emissions of sulfur dioxide, nitrogen oxides, fluorides, and sulfuric acid mist, as well as other acid gases which are not "regulated" under the PSD Rule, represent a significant proportion of the total emissions and need to be controlled if deemed appropriate. Sulfur dioxide emissions from combustion turbines are directly related to the sulfur content of the fuel being combusted.

The applicant has proposed the use of natural gas and No. 2 fuel oil with an average sulfur content of 0.30% to control sulfur dioxide emissions. A review of the latest edition (1989) of the BACT/LAER Clearinghouse indicates that sulfur dioxide emissions from combustion turbines have been controlled by limiting fuel oil sulfur content to a range of 0.1 to 0.3%, with the average for the facilities listed being approximately 0.24 percent. As this is the case, the applicant's proposal appears to be reasonable and is judged to represent BACT

The applicant has stated that BACT for nitrogen oxides will be met by using wet (water or steam) injection necessary to limit emissions to 65 ppmvd or 42 ppmvd at 15% oxygen when burning No. 2 fuel oil or natural gas, respectively.

A review of the EPA's BACT/LAER Clearinghouse indicates that the lowest NOx emission limit established to date for a combustion turbine is 4.5 ppmvd at 15% percent oxygen. This level of control was accomplished through the use of water injection and a selective catalytic reduction (SCR) system.

Selective catalytic reduction is a post-combustion method for control of NOx emissions. The SCR process combines vaporized ammonia with NOx 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 NOx with a new catalyst. As the catalyst ages, the maximum NOx reduction will decrease.

Given the applicant's proposed BACT level for nitrogen oxides control stated above, an evaluation can be made of the cost and associated benefit of using SCR as follows:

The applicant has indicated that the total levelized annual cost (operating plus amortized capital cost) to install SCR for natural gas firing at 100 percent capacity factor is $12,085,000. Taking into consideration the total levelized annual cost, a cost/benefit analysis of using SCR can now be developed. At 100% capacity factor, it is estimated that the maximum annual NOx emissions with wet injection from the Hardee facility would be 4,205 tons/year.

Assuming that SCR will reduce the NOx emissions by an additional 80%, the SCR would control a maximum of 3,364 tons of NOx annually for natural gas firing. When this reduction is taken into consideration with the total levelized annual cost of $12,085,000, the cost per ton of controlling NOx is $3,592. This cost ($3,592/ton) is representative of costs that have been previously justified as BACT and explains why SCR for combined cycle cogeneration facilities is becoming common as a BACT not LAER requirement for facilities being permitted today.

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 is 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."

A review of the combined cycle facilities in which SCR has been established as a BACT requirement indicates that the majority of these facilities are for commercial cogeneration purposes in which the main incentive is to generate power for sale to utility companies or private customers. As this is the case, these facilities want to operate as much as possible. The Hardee Power Station, however, is to be used initially for peaking and cycling purposes. The applicant has stated that the initial capacity factors for the Hardee Power Station are not expected to exceed a cumulative lifetime capacity factor of 60 percent. As this is the case, a SCR requirement for all modes of operation may not be justified.

For peaking units the cost of SCR can be much more expensive than units operating at high capacity factors on a cost per ton of nitrogen oxides controlled basis. This variability in cost is attributed to the fixed cost using SCR which is independent of hours of operation. Thus as hours of operation decrease, the cost to control nitrogen oxides increases.

The applicant has indicated that the cost of using SCR to control NOx emissions increases substantially as the capacity factor is decreased from 100 percent. It is estimated that the cost to control NOx would be as high as $9,063 per ton if the facility were to operate at a 25 percent capacity factor.

For fuel oil firing the applicant has proposed an emission limit of 65 ppm. A review of recent permitting activities in other states indicates that several turbines of the size proposed for the Hardee Power Facility are also being proposed with NOx emission guarantees of 65 ppm for oil firing. For fuel firing the applicant has indicated that the cost of using SCR to control NOx emissions would increase above that which is expected for natural gas firing only. This is due to the formation of ammonium salts.

For the SCR process, ammonium salts can be formed due to the reaction of sulfur in the fuel oil and the ammonia injected. The ammonium salts formed have a tendency to plug and corrode the tubes of the heat recovery steam generator 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. Assuming that SCR could not be operated for oil fired operation, the cost of NOx control would range from $4,398 to $11,815 per ton depending on the capacity factor with an 80-20 mix of natural gas and oil. The cost of using SCR for NOx control at various fuel mixtures and capacity factors is shown in Table 1.

Environmental Impact Analysis

The predominant environmental impacts associated with this proposal would be related to the use of SCR if required for NOx control. The use of SCR results in emissions of ammonia, which may increase with increasing levels of NOx control. In addition, some catalysts may contain substances which are listed as hazardous waste, thereby creating an additional environmental burden. Since the facility is being proposed as a peaking unit and SCR use is unlikely, these impacts do not pose a problem.

In addition to the criteria pollutants, the impacts of toxic pollutants associated with the combustion of natural gas and No. 2 fuel oil have been evaluated. Two of the toxic pollutants (mercury and beryllium) exceed PSD significant levels. Other toxics are expected to be emitted in minimal amounts, with the total emissions combined to be less than one ton per year.

Although the emissions of the toxic pollutants could be controlled by particulate control devices such as a baghouse or scrubber, the amount of emission reductions would not warrant the added expense. As this is the case, the Department does not believe that the BACT determination would be affected by the emissions of the toxic pollutants associated with the firing of natural gas or No. 2 fuel oil.

Potentially Sensitive Concerns

With regard to controlling NOx emissions with SCR the applicant has identified the following technical limitations:

1. SCR is not technically applicable to the simple cycle portion of the combined cycle configuration, i.e., the combustion turbine by-pass stack exhaust, and

2. Continuous operation of SCR using distillate oil has not been demonstrated; and therefore, technical, economic and environmental uncertainties would result.

TABLE 1
ECONOMIC ANALYSIS OF SCR FOR NOx

100% Natural Gas Firing

Capacity Factor	25	30	40	50	60	70	80	90	100
Total Annual Cost ($ X 1,000)	7,622	7,790	8,126	8,462	9,186	9,911	10,636	11,360	12,085
NOx Removal									
Ton/Year	841	1,009	1,346	1,682	2,018	2,355	2,691	3,028	3,364
$ /Ton	9,063	7,719	6,039	5,031	4,551	4,209	3,952	3,752	3,592

80% Natural Gas Firing/20% No. 2 Fuel Oil Firing

Capacity Factor	25	30	40	50	60	70	80	90	100
Total Annual Cost ($ X 1,000)	7,560	7,716	8,027	8,338	9,038	9,737	10,437	11,137	11,837
NOx Removal									
Ton/Year	673	807	1,076	1,346	1,615	1,884	2,153	2,422	2,691
$ /Ton	11,237	9,557	7,457	6,196	5,597	5,169	4,848	4,598	4,398

BACT Determination by DER

Based on the information presented by the applicant, the Department believes that the use of SCR is not justifiable providing that the facility operates as initially intended (not to exceed a cumulative lifetime capacity factor of 60 percent). Table 1 indicates that at this level of operation the cost of using SCR to control NOx emissions would be at least $4,551 per ton for natural gas firing and even more expensive if No. 2 fuel oil was used to supplement natural gas firing. This cost ($4,551 per ton) is judged to be excessive when compared to EPA's guidelines of $3,000 to $4,000 per ton for NOx removal. However, at operational levels above a capacity factor of 60 percent, SCR shall be installed and specific emission limitations will be established as BACT for both natural gas and oil firing. For this reason, the Hardee Facility shall provide space in the HRSG to accommodate SCR.

For simple cycle operation the use of SCR is not technically feasible, thus the use of wet injection would be appropriate for combined cycle units operating below the capacity factor limitation and for the stand alone turbine.

For sulfur dioxide BACT is represented by firing natural gas or No. 2 fuel oil with an average sulfur content not to exceed 0.30 percent. The emission limitations for PM, PM_{10}, CO and VOC's are based on previous BACT determinations for similar facilities, with the heavy metals beryllium and mercury being addressed through the particulate limitation and sulfuric acid mist being addressed through the sulfur dioxide limitation. The emission limits for the Hardee Power Station are thereby established as follows:

Pollutant	Emission Limit Natural Gas Firing	 No. 2 Fuel Oil Firing
NOx *	42 ppmvd @ 15% O_2	65 ppmvd @ 15% O_2
SO_2	Natural gas as fuel	Sulfur content not to exceed 0.3%
PM & PM_{10}	5.0 lbs/hr per turbine	10.0 lbs/hr per turbine
CO	10 ppmvd	26 ppmvd
VOC	2 ppmvd	5 ppmvd
Sulfuric Acid Mist	Emissions limited by natural gas and No. 2 fuel oil firing	
Beryllium	Emissions limited by natural gas and No. 2 fuel oil firing	

Mercury	Emissions limited by natural gas and No. 2 fuel oil firing

*Nitrogen oxides emission limitation is based on limiting the cumulative lifetime capacity factor to 60 percent. If the applicant chooses to operate the facility in excess of this limitation, BACT will be re-evaluated for nitrogen oxides for both natural gas and oil firing.

Fugitive Dust

Fugitive dust during operation will be minimal due to movement of vehicles or mainteneance activities such as mowing.

5. Acid Rain

Rainfall acidity levels across Florida and other parts of the country have been ascribed in part to the air emissions from fossil fuel-fired power plants. Hence the requirement for emission controls on these plants, designed to reduce the potential acid causing factors. Generally, sulfur dioxide and oxides of nitrogen are believed to be the primary man-made agents contributing to rainfall acidification. However, a great deal remains unknown about the amount that these two gases contribute to the problem, as well as how and where the acidification takes place.

It should be noted that rainfall under unpolluted conditions tends to be somewhat acidic, on the order of pH 5.0. It appears that after a certain amount of time, estimated to be on the order of 1-4 days, these gases interact with sunlight, water vapor, ammonia, and many other chemical compounds in the atmosphere, which converts them to sulfuric acid and nitric acid. Scientists around the world are studying the rate of these reactions, which catalytic aids (sunlight, water, etc.) have the most effect driving the conversion, ways to prevent the end acidic product from affecting the environment, where the end product eventually makes it's impacts, and numerous other questions relating to the conversion reactions. It is generally agreed that the entire cause-effect-control relationship is very complex.

One feature that will mitigate some of the impact of the project is that the fuels to be used will either have or be required to have a very low sulfur content prior to the plant going into operation. These units will thus have less impact than that of other units which do not employ those fuels. Oxides of nitrogen will be controlled. Such control will also help mitigate the rainfall acidification problem. In balancing the need for power with the environmental impacts from the operation of the plant, at this time, the required use of the low sulfur fuel and combustion design seems to be the most relevant and effective way of addressing the plant's contribution to rainfall acidification.

8/15/90

State of Florida Department of Environmental Regulation
TECO Power Services/Seminole Electric Cooperative, Inc.
Hardee Power Station
PA 89-25

CONDITIONS OF CERTIFICATION

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STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL REGULATION

TECO POWER SERVICES/SEMINOLE ELECTRIC COOPERATIVE, INC.
TAMPA ELECTRIC COMPANY
HARDEE POWER STATION
PA 89-25

CONDITIONS OF CERTIFICATION

I. GENERAL

A. Definitions

The meaning of the terms used herein shall be governed by the definitions contained in Chapters 403, 378, 373, 372, and 253, Florida Statutes, and any regulation adopted pursuant thereto and the statutes and regulations of any agency. In the event of any dispute over the meaning of a term used in these conditions which is not defined in such statutes or regulations, such dispute shall be resolved by reference to the most relevant definitions contained in any other state or federal statute or regulation or, in the alternative, by the use of the commonly accepted meaning as determined by the department. As used herein:

1. "Application" shall mean the Site Certification Application for the Hardee Power Station, as supplemented.

2. "CFRPC" shall mean the Central Florida Regional Planning Council.

3. "DER" shall mean the Florida Department of Environmental Regulation.

4. "DHR" shall mean the Florida Department of State, Division of Historical Resources.

5. "DNR" shall mean the Florida Department of Natural Resources.

6. "Emergency conditions" shall mean urgent circumstances involving potential adverse consequences to human life or property as a result of weather conditions or other calamity, and necessitating new or replacement gas pipeline, transmission lines, or access facilities.

7. "Feasible" or "practicable" shall mean reasonably achievable considering a balance of land use impacts, environmental impacts, engineering constraints, and costs.

8. "GFWFC" shall mean the Florida Game and Freshwater Fish Commission.

9. "Lee transmission line" shall mean the corridor depicted in Attachment A .

10. "Linear facility" shall mean any one of the three transmission lines or the natural gas pipeline associated with the Hardee Power Station.

11. "M/C" shall mean mitigation/compensation.

12. "Pebbledale transmission line" shall mean the corridor depicted in Attachment B.

13. "Permittees" shall mean TECO Power Services Corporation (TPS), Tampa Electric Company (TEC), and Seminole Electric Cooperative, Inc. (SECI).

14. "Power plant" shall mean the electric power generating equipment and appurtenances to be constructed on a site in Hardee County and Polk County, as generally depicted in the Application.

15. "Project" shall mean the Hardee Power Station and all associated facilities, including: The power plant and related facilities; the cooling reservoir and related facilities; any off-site mitigation/compensation areas; and all of the linear facilities.

16. "ROW" shall mean the transmission line and natural gas pipeline rights-of-way to be selected by the Permittees within the certified corridors in accordance with the conditions of certification.

17. "SFWMD" shall mean the South Florida Water Management District.

18. "SWFRPC" shall mean the Southwest Florida Regional Planning Council.

19. "SWFWMD" shall mean the Southwest Florida Water Management District.

20. "USFWS" shall mean the United States Fish and Wildlife Service.

21. "Vandolah transmission line" shall mean the corridor depicted in Attachment C.

22. "WMD" shall mean water management district.

23. "ISO" shall mean International Organization for Standardization, ISO 3977-1978(E) standard conditions for gas turbines = 14.7 psia, 15°C, relative humidity 60%.

B. Identification of Permittees Responsible for Compliance

In general, where a specific condition is intended to apply solely to one of the Permittees, this shall be indicated in the title for that specific condition by the following abbreviations:

TPS - TECO Power Services Corporation
TEC - Tampa Electric Company
SECI - Seminole Electric Cooperative, Inc.

Similarly, where a specific condition is intended to apply to any two of the Permittees, this shall be indicated by listing in the title the respective abbreviations. Where a specific condition is intended to apply to TPS, TEC, and SECI, the designation "HPS" (for "Hardee Power Station") shall appear.

C. Applicable Rules

The construction and operation of the HPS shall be in accordance with all applicable provisions of at least the following regulations of the Department: Chapters 17-2, 17-3, 17-4, 17-5, 17-6, 17-7, 17-12, 17-21, 17-22, 17-25, 17-274, 17-302, and 17-610, Florida Administrative Code (F.A.C.) or their sucessors as they are renumbered.

II. AIR (TPS)

A. Emission Limitations for HPS

The construction and operation of HPS shall be in accordance with all applicable provisions of Chapters 17-2, F.A.C. In addition to the foregoing, HPS shall comply with the following conditions of certification as indicated.

1. On or before April 1 of each year, the Permittee shall submit to the Division of Air Resource Management and the Air Section, Southwest District Office an annual report for the previous calendar year showing:

(a) The annual average capacity factor for each individual generating unit;

(b) The cumulative lifetime average capacity factor for each individual generating unit;

(c) The annual average capacity factor for the Hardee Power Station; and,

(d) The cumulative lifetime average capacity factor for the Hardee Power Station.

The annual average capacity factor shall be calculated by dividing each unit's megawatt hours output of generation by the product of the official megawatt rating of the unit and the number of hours in a year. Cumulative lifetime average capacity factor shall be calculated by dividing the cumulative total of megawatt hours output of generation by the product of the official combined cycle megawatt rating and the cumulative period of hours since commercial operation.

2. The Permittee shall install duct module(s) suitable for later installation of SCR equipment when constructing any combined cycle generating unit at the Hardee Power Station. Should any annual report demonstrate that the cumulative lifetime average capacity factor for the Hardee Power Station exceeds 60% at any time, the Permittee shall install SCR or another technology of equal or greater NOx reduction capability. In no event shall any such SCR or equivalent NOx control technology installation and compliance testing occur later than 30 months from the date that the Permittee requested or the facility exceeded the 60% cumulative lifetime average capacity factor.

3. Only natural gas or No. 2 fuel oil shall be fired in the turbine.

4. The maximum heat input to each CT shall neither exceed 1268.4 MMBtu/hr while firing natural gas, nor 1312.3 MMBtu/hr while firing fuel oil (@ 32°F). Each CT's fuel consumption shall be continuously measured and recorded.

5. The maximum allowable emissions from each CT in accordance with the BACT determination, shall not exceed the following:

Pollutant	Fuel	Emission Limitations	
		concentration	lb/hr/CT
NOx	Gas	42 ppmvd @ 15% O_2	215.9
	Oil	65 ppmvd "	383.8
VOC	Gas	2 ppmvd	3.6
	Oil	5 ppmvd	10.3
CO	Gas	10 ppmvd	31.3
	Oil	26 ppmvd	93.4
PM/PM_{10}	Gas	--	5.0
	Oil	--	10.0
SO_2	Gas	--	35.8
	Oil	0.3% S oil	734.4

6. The following allowable emissions, most determined by BACT, are tabulated for PSD and inventory purposes:

Pollutant	Fuel	Maximum Allowable Emission (@ 32°F) concentration	lb/hr/CT
H_2SO_4 Acid Mist	Gas	---	1.6
	Oil	---	22.0 (avg)/33.7 (max)
Mercury	Gas	---	0.0144
	Oil	---	0.0039
Fluoride	Oil	---	0.0427
Beryllium	Oil	---	0.0333

NOTE: Sulfur dioxide emissions assume a maximum of 0.5 percent sulfur in fuel oil for hourly emissions and an average sulfur content of 0.3 percent for annual emissions.

7. Visible emissions shall neither exceed 10% opacity while burning natural gas, nor 20% opacity while burning distillate oil.

8. Initial (I) compliance tests shall be performed using both fuels. The stack test for each turbine shall be performed within 10% of the maximum heat rate input for the tested operating temperature. Annual (A) compliance tests shall be performed on each Combustion Turbine with the fuel(s) used for more than 400 hours in the preceding 12-month period. Tests shall be conducted using EPA reference methods in accordance with the July 1, 1988 version of 40 CFR 60 Appendix A:

a. 5 for PM (I,A)
b. 8 for sulfuric acid mist (I, for oil only)
c. 9 for VE (I,A)
d. 10 for CO (I,A)
e. 20 for NOx (I,A)
f. 25A for VOC (I,A)
g. 104 for Beryllium (I, for distillate oil only) A fuel analysis for Be using either Method 7090 or 7091, and sample extraction using Method 3040, as described in the EPA solid waste regulations SW 846, is also acceptable.
h. ASTM D 2880-71 for sulfur content of distillate oil (I,A)
i. ASTM D 1072-80, D 3031-81, D 4084-82 or D 3246-81 for sulfur content of natural gas (I, and A if deemed necessary by DER)

Other DER approved methods may be used for compliance testing after prior Departmental approval.

9. The average annual sulfur content of the No. 2 fuel oil shall not exceed 0.3% by weight. The maximum sulfur content of the No. 2 fuel oil shall not exceed 0.5%. Compliance shall be demonstrated in accordance with the requirements of 40 CFR 60.334 by testing all oil shipments for sulfur content using ASTM D 2880-71, and testing for nitrogen content.

10. For all generating units, water injection shall be utilized for NOx control. The water to fuel ratio at which compliance is achieved shall be incorporated into the permit and shall be continuously monitored for all units.

11. To determine compliance with the capacity factor condition, the Permittee shall maintain daily records of power generation for each turbine. All records shall be maintained for a minimum of three years after the date of each record and shall be made available to representatives of the Department upon request.

12. The project shall comply with all the applicable requirements of Chapter 17-2, Florida Administrative Code (F.A.C.) and the July 1, 1988, version of 40 CFR 60 Subpart GG, Gas Turbines.

13. Any change in the method of operation, fuels, equipment, or phase design, shall be submitted for approval to DER's Bureau of Air Regulation.

14. If start/black start capability for the CTs is provided by a combustion unit, the Department shall be notified of the type/model, output capacity, anticipated hours of operation, and air emissions of the unit.

15. The Permittee shall have required sampling tests of the emissions performed within 60 days after achieving the maximum turbine firing rate, but not later than 180 days from the start of operation. Thirty (30) days prior notice of the initial sampling test and fifteen (15) days notice before subsequent annual testing shall be provided to the Southwest District Office. Written reports of the tests shall be submitted to the Southwest District office within 45 days of test completion.

16. If construction does not commence on the first three units within 18 months of issuance of this certification/permit, then the Permittee shall obtain from DER a review and, if necessary, a modification of the control technology and allowable emissions for the unit(s) on which construction has not commenced (40 CFR 52.21(r)(2). Units to be constructed in later phases of the project will be reviewed and limitations established under the supplementary review process of the Power Plant Siting Act.

17. Quarterly excess emission reports, in accordance with the July 1, 1988 version 40 CFR 60.7 and 60.334 shall be submitted to DER's Southwest District office. Annual reports shall be submitted to the District office in accordance with F.A.C. Rule 17-2.700(7).

18. Literature of equipment selected shall be submitted as it becomes available. A CT-specific graph of the relationship between NOx emissions and water injection, and also another of ambient temperature and heat inputs to the CT shall be submitted

to DER's Southwest District office and the Bureau of Air Regulation.

19. Stack sampling facilities shall be provided for both the bypass stack (CT) and the main stack (HRSG).

20. Construction period fugitive dust emissions shall be minimized by covering or watering dust generation areas.

III. SURFACE WATER DISCHARGES (TPS)

Discharges into surface waters of the state during construction and operation of the project shall be in accordance with applicable provisions of Chapters 17-3, 17-4, 17-302, 17-650, and 17-660, Florida Administrative Code, and the following conditions of certification:

A. Plant Effluents and Receiving Body of Water

For discharges made from the HPS the following conditions shall apply:

1. Receiving Body of Water (RBW) - The receiving body of water has been determined by the Department to be those waters of Payne Creek which are considered to be waters of the State within the definition of Chapter 403, Florida Statutes.

2. Point of Discharge (POD) - The point of discharge has been determined by the Department to be where the effluent physically enters the waters of the State in Payne Creek from either the storm water runoff retention pond or the cooling reservoir; however, compliance monitoring will be required at the cooling pond overflow weir and the stormwater detention pond discharge pipes.

3. Thermal Mixing Zones - The instantaneous zone of thermal mixing for the HPS cooling system shall not exceed a distance of 50 feet from the POD. The temperature at the POD into Payne Creek shall not be greater than 95 degrees F. The temperature of the water at the edge of the mixing zone shall not exceed the limitations of Section 17-302.520(5)(b), F.A.C.

4. Chemical Wastes from HPS - All discharges of low volume wastes (demineralizer regeneration, floor drainage, labs drains, and similar wastes) shall be treated in an adequately sized and constructed treatment facility prior to discharge into the cooling reservoir.

5. pH - The pH of the combined discharges to the cooling reservoir from Outfall Serial Number (OSN) 003 shall be such that the pH will fall within the range of 6.0 to 9.0 and any discharge from the reservoir at OSN 001 to Payne Creek shall not fall outside the 6.0 to 8.5 range.