Florida Department of Environmental Regulation

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

July 5, 1989

Mr. Wayne Aronson, Chief
Program Support Section
U.S. EPA, Region IV
345 Courtland Street, N.E.
Atlanta, Georgia 30365

Dear Mr. Aronson:

RE: TECO Power Services Corp./Seminole Electric Cooperative
Hardee Power Station/Power Plant Siting Application
PSD-FL-140

Enclosed for you review and comment are Volumes I and II of the above referenced application. Please direct any comments or questions to Pradeep Raval, Barry Andrews, or Max Linn at the above address or (904)488-1344 by August 1, 1989.

Sincerely,

Patricia G. Adams

Patricia G. Adams
Planner
Bureau of Air Quality
Management

/pa

Enclosures

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1.0 INTRODUCTION

The Hardee Power Station, will consist of a combined cycle power plant that will burn natural gas and distillate fuel oil. The facility will be constructed in modules that will consist of combustion turbines and associated electric generator, and heat recovery steam generators (HRSG); the HRSG will utilize the waste heat from the combustion turbines to generate steam for producing additional electricity in a steam turbine. Each module will have a nominal generating capacity of 220 MW (net) and would likely consist of two combustion turbines and associated electric generators, and two HRSGs and one steam electric generator. The ultimate capacity of the facility is being planned for 660 MW; however, but only 295 MW will be initially constructed.

The Hardee Power Station will emit air pollutants above regulatory threshold amounts which will require a Prevention of Significant Deterioration (PSD) review promulgated under 40 Code of Federal Regulations (CFR) Part 52.21 and implemented through delegation by the Florida Department of Environmental Regulation (FDER) and its regulations codified in Chapter 17-2.510 Florida Administrative Code (F.A.C.). This document provides the technical information and analyses required by these regulations. The information and analyses provided herein are based on a nominal 660 MW plant configuration; however they are transferable for smaller configurations since conservative emissions and impact analyses were assumed.

While this document is an appendix to the Site Certification Application (SCA), it has been prepared as a stand alone PSD application. The application is divided into seven major sections. Section 2.0 presents a description of the facility, and emissions and stack parameters. PSD review requirements and applicability are presented in Section 3.0. The control technology review, including the Best Available Control Technology (BACT) evaluation is presented in Section 4.0. Sections 5.0, 6.0, 7.0 and 8.0 present the air quality monitoring information and the methodology and results of the impact analyses performed for the project.

2.0 PROJECT DESCRIPTION

2.1 GENERAL DESCRIPTION

The combined cycle facility will be constructed in modules to achieve the desired capacity additions. The final design will depend on the selected combustion turbine with up to 6 combustion turbines required to achieve the ultimate capacity of 660 MW. Both simple cycle and combined cycle operation are planned; the latter would use by-pass stacks when only combustion turbine operation is needed, or the steam cycle is inoperable. The HRSG would not be supplementally fired.

2.2 FACILITY EMISSIONS AND STACK OPERATING PARAMETERS

The performance information and stack parameters that envelope the combustion turbine manufacturer's designs currently being considered for the project are presented in Table 2-1. This information provides conservative emission estimates of criteria pollutants (Table 2-2), other regulated pollutants (Table 2-3), and non-regulated pollutants (Table 2-4). Specific manufacturer designs would provide emissions no greater than those shown in these tables. The fuel specifications for natural gas and distillate oil are presented in Tables 2-5 and 2-6, respectively.

The maximum potential air quality impacts will occur during combined cycle operation when the exhaust temperature is 240°F. In addition, lower exhaust flow rates will occur for smaller combustion turbines which could also influence predicted impacts. As a result, the range in stack parameters used in modeling as well as corresponding sulfur dioxides (SO_2) emissions are presented in Table 2-7.

Table 2-1. Maximum Design and Stack Parameters for Each Combustion Turbine Associated with the Hardee Power Station Combined Cycle Plant

Data	Gas Turbine Natural Gas @ 32°F	Gas Turbine No.2 Oil @ 32°F	Gas Turbine Natural Gas @ 95°F	Gas Turbine No.2 Oil @ 95°F
General:				
Heat Input (mmBtu/hr)	1,268.4	1,312.3	1,074.1	1,107.2
Natural Gas (mcf/hr)	1,251.4	NA	1,059.8	NA
Fuel Oil (lb/hr)	NA	73,437.1	NA	61,956.3
Fuel:				
Heat Content - Gas (LHV)	1014 Btu/cf	NA	1014 Btu/cf	NA
Heat Content - Oil (LHV)	NA	17,870 Btu/lb	NA	17,870 Btu/lb
% Sulfur	NA	0.5	NA	0.5
Stack:				
Volume Flow (acfm)	1,924,021	1,929,288	1,707,645	1,782,889
Volume Flow (scfm)	713,401	714,351	615,452	628,415
Mass Flow (lb/hr)	3,110,000	3,114,140	2,683,000	2,739,512
Temperature (°F)*	964	966	1,005	1,038
Diameter (ft)	16.0	16.0	16.0	16.0
Velocity (ft/sec)	159.5	159.9	141.6	147.8
Height (ft)	75.0	75.0	75.0	75.0
Moisture (%)	10.3	9.3	13.5	12.4
Oxygen (%)	12.8	12.1	12.5	12.0
Water Injected (lb/hr)	76,010	96,698	63,350	82,047

* Exhaust from HRSG Stack will be 240°F.

NA - Not Applicable

Note: Data Presented in this table represent the design information used to produce maximum emissions from a single combustion turbine. Tables 2-2 through 2-3 present the maximum estimated emissions.

Table 2-2. Maximum Estimated Emissions for Each Combustion Turbine Associated with the Hardee Power Station Combined Cycle Plant Criteria Pollutants

Pollutant	Gas Turbine Natural Gas @ 32°F	Gas Turbine No. 2 Oil @ 32°F	Gas Turbine Natural Gas @ 95°F	Gas Turbine No. 2 Oil @ 95°F
Particulate:				
Basis*	0.8 g/s	7.2 g/s	0.63 g/s	6 g/s
lb/hr	6.3	57.1	5.6	55.5
TPY	27.8	250.1	24.3	243.1
Sulfur Dioxide:				
Basis*	20 gr/100 scf	0.5 % Sulfur	20 gr/100 scf	0.5 % Sulfur
lb/hr	35.75	734.37	30.28	619.56
TPY	156.6	3,216.5	132.6	2,713.7
Nitrogen Oxides:				
Basis*	42 ppm**	65 ppm**	42 ppm**	65 ppm**
lb/hr	215.9	383.8	174.9	311.5
TPY	945.7	1,680.9	766.0	1,364.3
ppm	42.0	65.0	42.0	65.0
Carbon Monoxide:				
Basis*	41 ppm**	13 ppm**	41 ppm**	13 ppm**
lb/hr	128.3	46.7	103.9	37.9
TPY	562.0	204.6	455.2	166.1
ppm	41.0	13.0	41.0	13.0
VOC's:				
Basis*	10 ppm**	10 ppm**	10 ppm**	10 ppm**
lb/hr	17.9	20.5	14.5	16.7
TPY	78.2	89.9	63.4	73.0
ppm	10.0	10.0	10.0	10.0
Lead:				
Basis		USEPA(1988)		USEPA(1988)
lb/hr	neg.	0.01	neg.	0.01
TPY	neg.	0.05	neg.	0.04

* From manufacturers estimates.
** Corrected to 15% O2 dry conditions.
Neg. = negligible

Emission factors used: No. 2 Fuel Oil; Lead - 8.9 lb/10^{12} Btu from USEPA (1988).

Table 2-3. Maximum Estimated Emissions for Each Combustion Turbine Associated with the Hardee Power Station Combined Cycle Plant Other Regulated Pollutants

Pollutant	Gas Turbine Natural Gas @ 32°F	Gas Turbine No. 2 Oil @ 32°F	Gas Turbine Natural Gas @ 95°F	Gas Turbine No. 2 Oil @ 95°F
Arsenic (As) (lb/hr)	neg.	0.0055	neg.	0.0047
(TPY)	neg.	0.0241	neg.	0.0204
Beryllium (Be) (lb/hr)	neg.	0.0033	neg.	0.0028
(TPY)	neg.	0.0144	neg.	0.0121
Mercury (Hg) (lb/hr)	0.0144	0.0039	0.0122	0.0033
(TPY)	0.0633	0.0172	0.0536	0.0145
Fluorides (F) (lb/hr)	neg.	0.0427	neg.	0.0360
(TPY)	neg.	0.1868	neg.	0.1576
H2SO4 Mist (lb/hr)	1.6	33.7	1.4	28.4
(TPY)	7.2	147.6	6.1	124.6

Neg. = Negligible
Emission factors used:
Natural gas:
Hg - 11.34 lb/10^{12} Btu,
H_2SO_4 mist - 3% of Sulfur Emissions;

No. 2 Fuel Oil:
As - 4.2 lb/10^{12} Btu, Be - 2.5 lb/10^{12} Btu,
Hg - 3.0 lb/10^{12} Btu, F^- - 32.5 lb/10^{12} Btu,
H_2SO_4 mist - 3% of Sulfur Emissions.

Sources: USEPA, 1980 for Hg from natural gas firing; USEPA 1981 for F^- from oil USEPA, 1988 for all others.

Table 2-4. Maximum Estimated Emissions for Each Combustion Turbine Associated with the Hardee Power Station Combined Cycle Plant Non-Regulated Pollutants

Pollutant	Gas Turbine Natural Gas @ 32°F	Gas Turbine No. 2 Oil @ 32°F	Gas Turbine Natural Gas @ 95°F	Gas Turbine No. 2 Oil @ 95°F
Manganese (lb/hr)	neg.	0.0085	neg.	0.0071
(TPY)	neg.	0.0370	neg.	0.0312
Nickel (lb/hr)	neg.	0.2231	neg.	0.1882
(TPY)	neg.	0.9772	neg.	0.8244
Cadmium (lb/hr)	neg.	0.0138	neg.	0.0116
(TPY)	neg.	0.0604	neg.	0.0509
Chromium (lb/hr)	neg.	0.0623	neg.	0.0526
(TPY)	neg.	0.2730	neg.	0.2303
Copper (lb/hr)	neg.	0.3674	neg.	0.3100
(TPY)	neg.	1.6094	neg.	1.3578
Vanadium (lb/hr)	neg.	0.0915	neg.	0.0772
(TPY)	neg.	0.4007	neg.	0.3381
Selenium (lb/hr)	neg.	0.0308	neg.	0.0260
(TPY)	neg.	0.1349	neg.	0.1138
POM (lb/hr)	0.0008	0.0004	0.0007	0.0003
(TPY)	0.0036	0.0016	0.0031	0.0014
Formaldehyde (lb/hr)	0.1120	0.5315	0.0949	0.4484
(TPY)	0.4906	2.3279	0.4155	1.9640

Neg. = Negligible

Emission Factors Used:

Natural Gas: Polycyclic Organic Matter (POM) - 0.65 lb/10^{12} Btu, Formaldehyde - 0.088 lb/10^{9} Btu;

No. 2 Fuel Oil: Manganese - 6.44 lb/10^{12} Btu, Nickel - 170 lb/10^{12} Btu, Cadmium - 10.5 lb/10^{12} Btu, Chromium - 47.5 lb/10^{12} Btu, Copper - 280 lb/10^{12} Btu, Vanadium - 69.7 lb/10^{12} Btu, Selenium - 23.5 lb/10^{12} Btu, POM - 0.279 lb/10^{12} Btu (emission factor indicated as a less than in reference), Formaldehyde - 405 lb/10^{12} Btu.

Source: USEPA, 1988.

Table 2-5. Typical Natural Gas Specification*

Constituents, Percent by Volume	
Hydrogen (H_2)	--
Methane (CH_4)	83.40
Ethylene (C_2H_4)	--
Ethane (C_2H_6)	15.80
Carbon Monoxide (CO)	--
Carbon Dioxide (CO_2), max.	2.0
Nitrogen (N_2)	0.80
Oxygen (O_2), max.	0.40
Hydrogen Sulfide (H_2S), max.	1 grain/100 SCF
Water (H_2O) Vapor, max.	4 lb/10^6 SCF
Synthetic Lubricants (Phosphate-Ester Based)	Trace
Specific Gravity (relative to air)	0.636
Ultimate, Percent by Weight	
Sulfur (S), max.	20 grains/100 SCF
Hydrogen (H_2)	23.53
Carbon (C)	75.25
Nitrogen (N_2)	1.22
Oxygen (O_2)	--
Btu/ft^3 @ 60 F and 30 inches HgA (HHV)	950 (min) - 1129
Btu/lb of Fuel (HHV)	23,170
(LHV)	20,870

* Pipeline Grade.

Table 2-6. Typical Fuel Oil Specification*

Specific gravity, 60°F	0.82 - 0.86
Viscosity, cSt, 100°F, min.	0.5
Pour point, max, °F	0
Gross heating value, kcal/kg	10,500 - 10,950
Gross heating value, Btu/lb	19,000 - 19,600
Filterable dirt, mg/100 ml	4
Carbon residue (10% Bottoms), %, max.	0.25
Carbon residue (100% Sample), %, max.	1.0
Sulfur, %, maximum	0.5
Nitrogen, %	0.005 - 0.015
Hydrogen, %	12.2 - 13.2
Ash (fuel as delivered), ppm, max.	50
Trace metal contaminants (untreated)	
Sodium plus potassium, ppm, max.	1
Vanadium, ppm, max.	0.5
Lead, ppm, max.	1
Calcium, ppm, max.	2

* Specification is typical of American Society of Testing and Materials (ASTM) Grade of No. 2 (ASTM D-398).

Table 2-7. Stack Parameters and SO_2 Emissions Used in Modeling for the Hardee Power Station

	Highest Emission		Lowest Flow Rate	
	32°F	95°F	32°F	95°F
Stack Gas Flow (ACFM)	947,056	833,126	770,627	654,455
Stack Gas Temperature (°F)	240	240	240	240
Stack Velocity (ft/sec)	78.5	69.1	63.9	54.2
Stack Diameter (ft)	16	16	16	16
Stack Height (ft)*	75	75	75	75
SO_2 Emissions (lb/hr)	734.37	619.56	558.04	456.34

* This stack height was used for the HRSG exhaust along with worst case structure dimensions (see Table 6-13) to conservatively estimate air quality impacts.

3.0 AIR QUALITY REVIEW REQUIREMENTS AND APPLICABILITY

The following discussion pertains to the federal and state air regulatory requirements and their applicability to the project. These regulations must be satisfied before the proposed facility can operate.

3.1 NATIONAL AND STATE AAQS

The existing applicable National and Florida ambient air quality standards (AAQS) are presented in Table 3-1. Primary National AAQS were promulgated to protect the public health, and secondary National AAQS were promulgated to protect the public welfare from any known or anticipated adverse affects associated with the presence of pollutants in the ambient air. Areas of the country in violation of AAQS are designated as nonattainment areas, and new sources to be located in or near these areas may be subject to more stringent air permitting requirements.

3.2 PSD REQUIREMENTS

3.2.1 General Requirements

Under federal PSD review requirements, all major new or modified sources of air pollutants regulated under the Clean Air Act (CAA) must be reviewed and approved by the U.S. Environmental Protection Agency (USEPA). (For sources in Florida, PSD review and approval has been delegated to FDER.) A "major stationary source" is defined as any one of 28 named source categories which has the potential to emit 100 tons per year (TPY) or more, or any other stationary source which has the potential to emit 250 TPY or more, of any pollutant regulated under CAA. "Potential to emit" means the capability, at maximum design capacity, to emit a pollutant after the application of control equipment.

A "major modification" is defined under PSD regulations as a change at an existing major stationary source which increases emissions by greater than "significant amounts." PSD significant emission rates are shown in Table 3-2.

Table 3-1. National and State AAQS, Allowable PSD Increments, and Significance Levels (ug/m^3)

Pollutant	Averaging Time	AAQS National Primary Standard	AAQS National Secondary Standard	AAQS State of Florida	PSD Increments Class I	PSD Increments Class II	Significant Impact Levels
Particulate Matter (TSP)	Annual Geometric Mean	NA	NA	NA	5	19	1
	24-Hour Maximum+	NA	NA	NA	10	37	5
Particulate Matter (PM10)	Annual Arithmetic Mean	50	50	50	NA	NA	1
	24-Hour Maximum*	150	150	150	NA	NA	5
Sulfur Dioxide	Annual Arithmetic Mean	80	NA	60	2	20	1
	24-Hour Maximum+	365	NA	260	5	91	5
	3-Hour Maximum+	NA	1,300	1300	25	512	25
Carbon Monoxide	8-Hour Maximum+	10,000	10,000	10,000	NA	NA	500
	1-Hour Maximum+	40,000	40,000	40,000	NA	NA	2000
Nitrogen Dioxide	Annual Arithmetic Mean	100	100	100	2.5**	25**	1
Ozone	1-Hour Maximum++	235	235	235	NA	NA	NA
Lead	Calendar Quarter Arithmetic Mean	1.5	1.5	1.5	NA	NA	NA

+ Maximum concentration not to be exceeded more than once per year.

* Achieved when the expected number of exceedances per year is less than 1.0.

** The State of Florida has not yet adopted the PSD Increments for NO_2 concentrations.

++ Achieved when the expected number of days per year with concentrations above the standard is less than 1.0.

NA = Not applicable, i.e., no standard exists.

Sources: Federal Register, Vol. 43, No. 118, June 19, 1978.
40 CFR 50
40 CFR 52.21

Table 3-2. PSD Significant Emission Rates and _De_ _Minimis_ Air Quality Impact Concentrations

Pollutant	Regulated Under	Significant Emission Rate (TPY)	_De_ _Minimis_ Air Quality Impact (ug/m^3)
Sulfur Dioxide	NAAQS, NSPS	40	13, 24-hour
Particulate Matter (TSP)	NAAQS, NSPS	25	10, 24-hour
Particulate Matter (PM10)	NAAQS	15	10, 24-hour
Nitrogen Oxides	NAAQS, NSPS	40	14, Annual
Carbon Monoxide	NAAQS, NSPS	100	575, 8-hour
Volatile Organic Compounds (Ozone)	NAAQS, NSPS	40	100 TPY+
Lead	NAAQS	0.6	0.1, 3-month
Sulfuric Acid Mist	NSPS	7	*
Total Fluorides	NSPS	3	0.25, 24-hour
Total Reduced Sulfur	NSPS	10	10, 1-hour
Reduced Sulfur Compounds	NSPS	10	10, 1-hour
Hydrogen Sulfide	NSPS	10	0.2, 1-hour
Asbestos	NESHAP	0.007	*
Beryllium	NESHAP	0.0004	0.001, 24-hour
Mercury	NESHAP	0.1	0.25, 24-hour
Vinyl Chloride	NESHAP	1	15, 24-hour
Benzene	NESHAP	0	*
Radionuclides	NESHAP	0	*
Inorganic Arsenic	NESHAP	0	*

*No ambient measurement method.
+Increases in VOC emissions.

Notes: Ambient monitoring requirements for subject pollutants may be exempted if the impact of the increase in emissions is below air quality impact _de_ _minimis_ levels.
NAAQS = National Ambient Air Quality Standards.
NSPS = New Source Performance Standards.
NESHAP = National Emission Standards for Hazardous Air Pollutants.

Sources: 40 CFR 52.21.
Chapter 17-2, Florida Administrative Code

PSD review is used to determine whether significant air quality deterioration will result from the new or modified source. PSD requirements are contained in 40 CFR 52.21, Prevention of Significant Deterioration of Air Quality. Major sources and modifications are required to undergo the following analysis related to PSD for each pollutant emitted in "significant" amounts:

1. Control technology review,
2. Source impact analysis,
3. Air quality analysis (monitoring),
4. Source information, and
5. Additional impact analyses.

In addition to these analyses, a new source must also be reviewed with respect to Good Engineering Practice (GEP) stack height regulations. Discussions concerning each of these requirements are presented in the following sections.

3.2.2 Increments/Classifications

In promulgating the 1977 CAA Amendments, Congress specified that certain increases above an air quality "baseline concentration" level of SO_2 and PM concentrations would constitute "significant deterioration." The magnitude of the allowable increment depends on the classification of the area in which a new source (or modification) will be located or have an impact. Three classifications were designated based on criteria established in the CAA Amendments. Initially, Congress promulgated areas as Class I (international parks, national wilderness areas, and memorial parks larger than 5,000 acres, and national parks larger than 6,000 acres) or as Class II (all areas not designated as Class I). Class III areas, which would be allowed greater deterioration than Class II areas, have not been designated. USEPA then promulgated as regulations the requirements for classifications and area designations.

On October 17, 1988, the USEPA promulgated regulations to prevent significant deterioration due to NO_x emissions and established PSD increments for NO_2 concentrations. The USEPA class designations and allowable PSD increments are presented in Table 3-1. The Florida DER has adopted the USEPA class designations and allowable PSD increments for SO_2 and PM but has not yet adopted the NO_2 increments.

The term "baseline concentration" evolves from federal and state PSD regulations and denotes a fictitious concentration level corresponding to a specified baseline date and certain additional baseline sources. By definition in the PSD regulations, as amended August 7, 1980, baseline concentration means the ambient concentration level which exists in the baseline area at the time of the applicable baseline date. A baseline concentration is determined for each pollutant for which a baseline date is established and includes:

1. The actual emissions representative of sources in existence on the applicable baseline date; and
2. The allowable emissions of major stationary sources which commenced construction before January 6, 1975, but were not in operation by the applicable baseline date.

The following emissions are not included in the baseline concentration and therefore affect PSD increment consumption:

1. Actual emissions from any major stationary source on which construction commenced after January 6, 1975 for SO_2 and TSP concentrations and February 8, 1988, for NO_2 concentrations; and
2. Actual emission increases and decreases at any stationary source occurring after the baseline date.

"Baseline date" means the earliest date after August 7, 1977 for SO_2 and TSP concentrations and February 8, 1988, for NO_2 concentrations, on which the first complete application under 40 CFR 52.21 is submitted by a major stationary source or major modification subject to the requirements of 40 CFR 52.21.

3.2.3 Control Technology Review

The control technology review requirements of the federal PSD regulations require that all applicable federal and state emission limiting standards be met and that Best Available Control Technology (BACT) be applied to control emissions from the source (40 CFR 52.21). The BACT requirements are applicable to all regulated pollutants for which the increase in emissions from the source or modification exceeds the significant emission rate (see Table 3-2).

BACT is defined in 40 CFR 52.21 as:

> An emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under the Act...which the Administrator, 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 or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant.... If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology.

The requirements for BACT were promulgated within the framework of PSD in the 1977 amendments of the CAA [Public Law 95-95; Part C, Section 165(a)(4)]. The primary purpose of BACT is to optimize consumption of PSD air quality increments and thereby enlarge the potential for future economic growth without significantly degrading air quality (USEPA, 1978; 1980). Guidelines for the evaluation of BACT can be found in USEPA's "Guidelines for Determining Best Available Control Technology (BACT)," (USEPA, 1978) and in the "PSD Workshop Manual" (USEPA, 1980). These guidelines were promulgated by USEPA to provide a consistent approach to BACT and to ensure that the impacts of alternative emission control systems are measured by the same set of parameters. In addition, through implementation of these guidelines, BACT in one area may not be identical to BACT in another area.

According to USEPA (1980), "BACT analyses for the same types of emissions unit and the same pollutants in different locations or situations may determine that different control strategies should be applied to the different sites, depending on site-specific factors. Therefore, BACT analyses must be conducted on a case-by-case basis."

The BACT requirements are intended to ensure that the control systems incorporated in the design of a proposed facility reflect the latest in control technologies used in a particular industry and take into consideration existing and future air quality in the vicinity of the proposed facility. BACT must, as a minimum, demonstrate compliance with NSPS for a source (if applicable). An evaluation of the air pollution control techniques and systems, including a cost-benefit analysis of alternative control technologies capable of achieving a higher degree of emission reduction than the proposed control technology, is required. The cost-benefit analysis requires the documentation of the materials, energy, and economic penalties associated with the proposed and alternative control systems, as well as the environmental benefits derived from these systems. A decision on BACT is to be based on sound judgement, balancing environmental benefits with energy, economic, and other impacts (USEPA, 1978).

3.2.4 Air Quality Analysis

In accordance with requirements of 40 CFR 52.21(m), any application for a PSD permit must contain an analysis of continuous ambient air quality data in the area affected by the proposed major stationary source or major modification. For a new major source, the affected pollutants are those that the source would potentially emit in significant amounts. For a major modification, the pollutants are those for which the net emissions increase exceeds the significant emission rate (see Table 3-2).

According to CAA, ambient air monitoring for a period of up to 1 year is generally appropriate to satisfy the PSD monitoring requirements. A minimum of four (4) months of data is required. Existing data from the vicinity of the proposed source may be utilized if the data meet certain quality assurance requirements; otherwise, additional data may need to be gathered. Guidance in designing a PSD monitoring network is provided in USEPA's "Ambient Monitoring Guidelines for Prevention of Significant Deterioration" (USEPA, 1987a).

The regulations include an exemption which excludes or limits the pollutants for which an air quality analysis must be conducted. This exemption states that the Administrator may exempt a proposed major stationary source or major modification from the monitoring requirements of 40 CFR 52.21(m) with respect to a particular pollutant if the emissions increase of the pollutant from the source or modification would cause, in any area, air quality impacts less than the de minimis levels presented in Table 3-2.

3.2.5 Source Impact Analysis

A source impact analysis must be performed by a proposed major source subject to PSD for each pollutant for which the increase in emissions exceeds the significant emission rate (Table 3-2). The PSD regulations specifically require the use of atmospheric dispersion models in performing impact analysis, estimating baseline and future air quality levels, and determining compliance with AAQS and allowable PSD increments. Designated USEPA models must normally be used in performing the impact analysis. Specific applications for other than USEPA-approved models require USEPA's consultation and prior approval. Guidance for the use and application of dispersion models is presented in the USEPA publication, "Guideline on Air Quality Models (Revised)" (USEPA, 1987b). The source impact analysis for criteria pollutants may be limited to only the new or modified source if the net increase in impacts due to the new or modified source is below significance levels, as presented in Table 3-1.

Various lengths of record for meteorological data can be utilized for impact analysis. A 5-year period can be used with corresponding evaluation of highest, second-highest short-term concentrations for comparison to AAQS or PSD increments. The term "highest, second-highest" refers to the highest of the second-highest concentrations at all receptors (i.e., the highest concentration at each receptor is discarded). The second-highest concentration is significant because short-term AAQS specify that the standard should not be exceeded at any location more than once a year. If less than 5 years of meteorological data are used in the modeling analysis, the highest concentration at each receptor must normally be used for comparison to air quality standards.

3.2.6 Additional Impact Analysis

In addition to air quality impact analyses, federal PSD regulations require analyses of the impairment to visibility and the impacts on soils and vegetation that would occur as a result of the proposed source. These analyses are to be conducted primarily for PSD Class I areas. Impacts due to general commercial, residential, industrial, and other growth associated with the source must also be addressed. These analyses are required for each pollutant emitted in significant amounts (Table 3-2).

3.2.7 Good Engineering Practice Stack Height

The 1977 CAA Amendments require that the degree of emission limitation required for control of any pollutant not be affected by a stack height that exceeds GEP, or any other dispersion technique. On July 8, 1985, USEPA promulgated final stack height regulations (USEPA, 1985). GEP stack height is defined as the highest of:

1. 65 meters (m), or
2. A height established by applying the formula:

   $Hg = H + 1.5L$

   where: H_g = GEP stack height,

   H = Height of the structure or nearby structure, and

   L = Lesser dimension (height or projected width) of nearby structure(s).
3. A height demonstrated by a fluid model or field study.

"Nearby" is defined as a distance up to five times the lesser of the height or width dimensions of a structure or terrain feature, but not greater than

0.8 km. Although GEP stack height regulations require that the stack height used in modeling for determining compliance with AAQS and PSD increments not exceed the GEP stack height, the actual stack height may be greater.

The stack height regulations also allow increased GEP stack height beyond that resulting from the above formula in cases where "plume impaction" occurs. Plume impaction is defined as concentrations measured or predicted to occur when the plume interacts with "elevated terrain." "Elevated terrain" is defined as terrain which exceeds the height calculated by the GEP stack height formula. Because the terrain in the vicinity of the proposed facility is flat, plume impaction was not considered in determining the GEP stack height.

3.3 NONATTAINMENT RULES

On August 7, 1980, USEPA promulgated rules for review of major new sources and major modifications in areas where air quality does not meet federal standards [Emission Offset Interpretative Ruling (40 CFR 51, Appendix S), which applies to new and modified major sources affecting nonattainment areas.] Under Section IV.A of the Ruling, such sources are required to: (1) meet an emission limitation which specifies the lowest achievable emission rate for such sources, (2) certify that all existing major sources owned or operated by the applicant in the same state are in compliance with all applicable emission limitations and standards under the Act, (3) obtain emission offsets such that there will be reasonable progress toward attainment of the applicable national AAQS, and (4) demonstrate that the emission offsets would provide a positive net air quality benefit in the affected area [not applicable for volatile organic compounds (VOC) or NO_x]. FDER has promulgated rules that are consistent with the USEPA requirements [17-2.510 Florida Administrative Code]. Based on these current nonattainment provisions, all major new sources and modifications to existing major sources located in the nonattainment area must undergo the nonattainment review procedures if the proposed facility or source has the potential to emit 100 TPY or more of the nonattainment pollutant, or the major modification results in a significant net emission increase at the facility of the nonattainment pollutant.

For major sources or major modifications which locate in an attainment or unclassifiable area, the nonattainment review procedures apply if the source or modification is located within the area of influence of a nonattainment area (F.A.C, Section 17-2.510). The area of influence is defined as an area which is outside the boundary of a nonattainment area but within the locus of all points that are 50 km outside the boundary of the nonattainment area. Based on F.A.C, Section 17-2.510(2)(a) 2.a, all VOC sources which are located within an area of influence are exempt from the provisions of new source review for nonattainment areas. Sources which emit other pollutants and are located within the area of influence are subject to nonattainment review unless the maximum allowable emissions from the proposed source do not have a significant impact within the nonattainment area.

3.4 SOURCE APPLICABILITY

3.4.1 PSD Review

3.4.1.1 Potential Emissions

The proposed facility would be considered a "major source" if the emission rate for one of the regulated pollutants exceeds 100 TPY. Once the source is considered to be a major source, PSD review is required for any pollutant that exceeds the PSD significant emission rates presented in Table 3-2. As presented in Table 3-3, the proposed source will have potential emissions of SO_2, NO_2, PM, CO, VOC, and sulfuric acid mist that are major and will exceed the PSD significant emission rates for Be, Hg and As. Therefore, the proposed facility is a major source and is subject to PSD review for those pollutants.

3.4.1.2 Area Classification

The proposed facility unit will be located in Hardee County which is designated by FDER as an attainment area for all criteria pollutants, and a PSD Class II area for SO_2, TSP and NO_2. The nearest nonattainment area is Hillsborough County which is nonattainment for ozone. Also, portion

Table 3-3. Potential Emissions and Predicted Impacts of the Project Compared to PSD Significant Emission Rates and De Minimis Air Quality Impacts Levels (Page 1 of 2)

Pollutant	Emissions (TPY) Potential From Proposed Source++	Significant Emission Rate	Impacts (ug/m^3) Predicted Impacts	De Minimus Air Quality Impact Level
Sulfur Dioxide	16,083	40	62.5	13, 24-hour
Particulate Matter (TSP)	1,250	25	7.5	10, 24-hour
Particulate Matter (PM10)	1,250	15	7.5	10, 24-hour
Nitrogen Dioxide	8,405	40	4.6	14, Annual
Carbon Monoxide	2,810	100	38.0	575, 8-hour
Votatile Organic Compounds	450	40	--	Emissions Increase of 100 TPY
Lead	0.25	0.6	**	0.1, Calendar quarter
Sulfuric Acid Mist	738	7	*	*
Total Fluorides	0.93	3	**	0.25, 24-hour
Total Reduced Sulfur	NEG	10	**	10, 1-hour
Reduced Sulfur Compounds	NEG	10	**	10, 1-hour
Hydrogen Sulfide	NEG	10	**	0.2, 1-hour
Asbestos	NEG	0.007	*	*
Beryllium	0.072	0.0004	0.0004	0.001, 24-hour
Mercury	0.32	0.1	0.0016	0.25, 24-hour
Vinyl Chloride	NEG	1	**	15, 24-hour
Benzene	NEG	0	*	*
Radionuclides	NEG	0	*	*
Inorganic Arsenic	0.12	0	+	*

Table 3-3. Potential Emissions and Predicted Impacts of the Project Compared to PSD Significant Emission Rates and De Minimis Air Quality Impacts Levels (Page 2 of 2)

Note : NA = Not applicable.
NEG = Negligible.

* No acceptable ambient measurement method has been developed and, therefore, de minimis levels have not been established by USEPA.
\+ Predicted impacts are presented in Section 8 to assess effects on soils and vegetation.
** Predicted impacts are not required because emissions are less than significant emission rates.
++ Based on 100 percent capacity factor at 100 percent load when firing oil at 32°F conditions; all pollutant emissions based on 5 combustion turbines which produce the maximum emisssions for an ultimate capacity of 660 MW.

of Hillsborough County has been reclassified by FDER from a TSP nonattainment area to unclassifiable for PM10. This change will go into effect upon USEPA approval. The proposed facility will also be located more than 100 km from the PSD Class I areas of the Chassahowitzka National Wilderness Area and the Everglades National Park. Because impacts from the proposed source's emissions are not expected to be significant at such distances, potential impacts on the Class I area were not addressed in the analysis.

3.4.1.3 Ambient Monitoring

Based upon the pollutant impacts presented in Table 3-3, a PSD preconstruction ambient monitoring analysis is required for SO_2, NO_2, PM, CO, VOC, sulfuric acid mist, Be, Hg and As. However, if the impact of these pollutant emissions is less than the de minimis levels, then an exemption from the preconstruction ambient monitoring requirement may be granted. Predicted impacts are less than de minimis levels for all pollutants, except SO_2 (refer to Table 3-3). For SO_2 concentrations, the Applicant has requested and received from the Florida DER an exemption from PSD preconstruction monitoring. For ozone concentrations, the de minimis air quality impact level is specified as an increase of 100 TPY or more of VOC emissions. Because the maximum potential VOC emissions from the proposed plant are greater than 100 TPY, preconstruction monitoring review is required for O_3 concentrations. However, because of the rural nature of the proposed site and locations of existing monitoring stations, data from existing monitoring stations will be used to fulfill the ambient monitoring requirements for this application. A more detailed discussion about the preconstruction monitoring exemption and use of existing ambient data is presented in Section 5.0.

3.4.1.4 GEP Stack Height Impact Analysis

The GEP stack height regulations allow any stack to be at least 65 meters high. The proposed stack heights are 75 and 90 ft (23 and 27 meters), respectively, for the by-pass and HRSG stacks; therefore, they do not exceed the GEP stack height. Impact analyses were performed with both stacks at

75 ft (23 m) to produce worst case ambient impacts. The potential for downwash of the units' emissions due to nearby structures is discussed in Section 6.0, Air Quality Modeling Approach.

3.4.2 Nonattainment Review

Although the proposed facility is located in an attainment area for all regulated pollutants, it may be subject to nonattainment review if it is located within the area of influence of a nonattainment area (F.A.C., Section 17-2.510).

The proposed facility is located approximately 9 km from Hillsborough County, which is designated as nonattainment for O_3 concentrations, and 40 km from that portion of Hillsborough County designated as nonattainment for TSP concentrations. Therefore, the proposed facility is located within the area of influence of both nonattainment areas. However, based on FDER regulations, the proposed facility is exempt from nonattainment review for VOC emissions but must comply with PSD review requirements. Based on the maximum concentrations predicted for the proposed facility presented in Section 7.0, the maximum allowable TSP emissions will produce impacts that are not significant within the reclassified nonattainment area. In fact, the proposed facility has a significant TSP impact that extends out to only about 10 km from the project site. Based on these results, the proposed facility is not subject to nonattainment review for either VOC or PM emissions.

4.0 CONTROL TECHNOLOGY REVIEW

4.1 APPLICABILITY

The Control Technology review requirements of the PSD regulations are applicable to emissions of NO_x, CO, SO_2, TSP/PM10, VOC, mercury, inorganic arsenic and sulfuric acid mist and beryllium (see Section 3.0). This section presents the applicable New Source Performance Standards (NSPS) and the proposed BACT for these pollutants. The approach to BACT analyses are based on the regulatory definitions of BACT.

4.2 NEW SOURCE PERFORMANCE STANDARDS

The applicable NSPS for gas turbines are codified in 40 CFR part GG. These regulations apply to:

1. "Electric utility stationary gas turbine" with a heat input at peak load of greater than 100 million Btu/hr [40 CFR 60.332 (b)];
2. "Stationary gas turbines" with a heat input at peak load between 10 and 100 million Btu/hr [40 CFR 60.332 (c)]; or
3. "Stationary gas turbines" with a manufacture's rate based load at ISO conditions of 30 MW or less [40 CFR 60.332 (d)].

The "electric utility stationary gas turbine" provisions apply to stationary gas turbines constructed for the purpose of supplying more than one-third of its potential electric output capacity to any utility power distribution system for sale [40 CFR 60.331 (q)]. The requirements for "electric utility stationary gas turbines" are applicable to the project and are the most stringent provision of the NSPS and are a technically feasible control alternative for the project. These requirements are summarized in Table 4-1 and were considered in the BACT analysis.

As noted from Table 4-1, the NSPS can be adjusted upward to allow for fuel bound nitrogen. For a fuel bound nitrogen concentration of 0.015% or less no increase in the NSPS is provided; for a fuel bound nitrogen concentration of 0.06% the NSPS is increased by 0.0024% or 24 ppm.

Table 4-1. Federal NSPS for Stationary Gas Turbines

Pollutant	Emission Limitation*
Sulfur Dioxide	Maximum of 0.015 percent by volume at 15 percent oxygen on a dry basis <u>or</u> sulfur in fuel no greater than 0.8 percent by weight
Nitrogen Oxides+	0.0075 percent by volume (75 ppm) at 15 percent O_2 on a dry basis adjusted for heat rate and fuel nitrogen

* Applicable to electric utility gas turbines with a heat input at peak load of greater than 100 x 10^6 Btu/hr.

\+ Standard is multiplied by 14.4/Y; where Y is the manufacturer's rated heat rate in kilojoules per watt at rated load or actual measured heat rate based on the lower heating value of fuel measured at actual peak load Y cannot be greater than 14.4.

** Standard is adjusted upward (additive) by the percent of nitrogen in the fuel:

Fuel-bound nitrogen (percent by weight)	Allowed Increase NO_x percent by volume
N<0.015............................	0
0.015<N<0.1........................	0.04(N)
0.1<N<0.25..........................	0.004+0.0067(N-0.1)
N>0.25..............................	0.005

where:
N = the nitrogen content of the fuel (percent by weight).

Source: 40 CFR 60 Subpart GG.

4.3 BEST AVAILABLE CONTROL TECHNOLOGY

4.3.1 Nitrogen Oxides

4.3.1.1 Emission Control Hierarchy

NO_x emissions from combustion of fossil fuels consist of thermal NO_x and fuel bound NO_x. Thermal NO_x is formed from the reaction of oxygen and nitrogen in the combustion air at combustion temperatures. Formation of thermal NO_x depends on the flame temperature, residence time, combustion pressure, and air to fuel ratios in the primary combustion zone. The design and operation of the combustion chamber dictates these conditions. Fuel bound NO_x is created by the oxidation of volatilized nitrogen in the fuel. Nitrogen content in the fuel is the primary factor in its formation.

Table 4-2 presents a listing of the LAER/BACT decisions for gas turbines made by state environmental agencies and EPA regional offices. This table was developed from the information contained in the LAER/BACT clearinghouse documents (USEPA, 1985, 1986b, 1987c 1988c) and by contacting state agencies such as the California Air Control Board and the South Coast Air Quality Management District.

Presently, there are about 35 operating and permitted facilities with Selective Catalytic (SCR) in the United States. Almost all of these facilities were required to have SCR due to nonattainment status of the area where the facility was located. The requirement for SCR in these cases was to meet the Lowest Achievable Emission Rate (LAER). LAER is defined as follows:

> Lowest achievable emission rate means, for any source, the more stringent rate of emissions based on the following: (i) The most stringent emissions limitation which is contained in the implementation of any State of such class or category of stationary source, unless the owner or operator of the proposed stationary source demonstrates that such limitations are not achievable; or (ii) The most stringent emissions limitation which is achieved in practice by such class or

Table 4-2. LAER/BACT Decisions

Company Name	State	Unit Description	Capacity (Size)	Date of Permit	Emission Limit	Emission Control
Virginia Power	VA	GE Turbine	1,875 MMBTU/hr	Apr-88	NOx 42ppm 490 lb/hr	Steam Injection W/Maximazation NSPS subpart GG
Trunkline LNG	LA	Gas Turbine	147,102 SCF/hr	May-87	NOx 59 lb/hr	
Wichita Falls E. I., I.	TX	Gas Turbine	20 MW	Jun-86	NOx 684 TPY CO 420 TPY	Steam Injection
Merck Sharp & Pohme	PA	Turbine	310 MMBTU/hr	May-88	NOx 42 ppm @ 15% O2	Steam Injection
California Dept. of Corr.	CA	*Gas Turbine*	5.1 MW	Dec-86	NOx 38 ppmv @ 15% O2	1 to 1 H2O injection
City of Santa Clara	CA	Gas Turbine		Jan-87	NOx 42 ppmvd @ 15% O2	Water Injection
Combined Energy Resources	CA	Cogeneration Fac.	27 MW	Mar-87	NOx 199 lb/D	SCR Unit, Duct Burner H2O Injection, Low NOx Design
Double 'C' Limited	CA	Gas Turbine	25 MW	Nov-86	NOx 194 lb/D	H2O Inj. & Selected Catalytic Red. 95.80 Efficiency
Kern Front Limited	CA	Gas Turbine	25 MW	Nov-86	NOx 194 lb/D 4.5 ppmvd @ 15% O2	H2O Inj. & Selected Catalytic Red. 95.80 Efficiency
Midway - Sunset Project	CA	Gas Turbine	973 MMBTU/hr	Jan-87	NOx 113.4 lb/hr 16.31 ppmv	H2O Injection, 73% Efficiency
O'Brien Energy Systems	CA	Gas Turbine	359.5 MMBTU/hr	Dec-86	NOx 30.3 lb/hr 15 ppmvd @ 15% O2	Duct Burner, H2O Injection and Scrubber
PG & E, Station T	CA	GE Gas Turbine	396 MMBTU/hr	Aug-86	NOx 25 ppm @ 15% O2 63 lb/hr	Steam Injection @ Steam/Fuel Ratio of 1.7/1, 75% Efficiency
Sierra LTD.	CA	GE Gas Turbine	11.34 MMCF/D		NOx 4.04 lb/hr 0.016 lb/MMBTU	Scrubber & CO Catalytic Converter Steam Injection 95.86 Efficiency

Table 4-2. LAER/BACT Decisions (Page 2 of 5)

Company Name	State	Unit Description	Capacity (Size)	Date of Permit	Emission Limit	Emission Control
Sycamore Cogeneration Co.	CA	Gas Turbine	75 MW	Mar-87	CO 10 ppmv @ 15% O2 3 hr Avg	CO Oxidizing Catalyst Combustion Control
U.S. Borax & Chemical Corp.	CA	Gas Turbine	45 MW	Feb-87	NOx 40 lb/hr 25 ppm @ 15% O2 Dry CO 23 lb/hr	Scrubber Proper Combust. Techniques
Western Power System, Inc	CA	GE Gas Turbine	26.5 MW	Mar-86	NOx 9 ppmvd @ 15% O2	H2O Injection, Selective Cat. Red. 80% Efficiency
Calcogen, Cal Polytechic	CA	Gas Turbine	21.4 MW	Apr-84	NOx 42 ppm @ 15% O2	H2O Injection, 70% Efficiency
Greenleaf Power Co.	CA	GE Gas Turbine	35.62 MW	Apr-85	NOx 42 ppm @ 15% O2 91 lb/hr CO 20.4 lb/hr	H2O Injection Good Eng. Practices
		Duct Burner	63.7 MMBTU/hr	Apr-85	NOx 0.1 lb/MMBTU 6.4 lb/hr CO 0.12 lb/MMBTU 7.6 lb/hr	Low NOx Design
OLS Energy	CA	GE Gas Turbine	256 MMBTU/hr	Jan-86	NOX 9 PPMVD @ 15% O2	H2O Injection & Scrubber 80% Eff. for Scrubber
Ciba Giegy Corp.	NJ	Gas Turbine	3 MW	Jan-85	NOx 11.06 lb/hr CO 9.4 lb/hr	SIP, H2O Injection, 55% Eff.
Energy Reserve, Inc.	CA	Gas Turbine	322.5 MMBTU/hr	Oct-85	NOx 185.4 lb/D	H2O Injection, Select. Cat. Red. 92.5% Efficiency
Gilroy Energy Co.	CA	Gas Turbine	60 MW	Aug-85	NOx 25 PPMDV @ 15% O2	Steam Inj., Quiet Combustor
		Auxiliary Boiler	90 MMBTU/hr		NOx 40 PPMDV @ 3% O2	Low NOx Burners

Table 4-2. LAER/BACT Decisions (Page 3 of 5)

Company Name	State	Unit Description	Capacity (Size)	Date of Permit	Emission Limit	Emission Control
Kern Energy Corp.	CA	Gas Turbine	8.8 MMCF/D	Apr-86	NOx 8.29 lb/hr 0.023 lb/MMBTU	Scrubber w/ NH3 Red. Agent Steam Inj. & Low NOx Config. Exh. Duct Burner 87% Efficiency
Moran Power, Inc.	CA	Gas Turbine	8.0 MMCF/D	Apr-86	NOx 8.29 lb/hr 0.023 lb/MMBTU	Scrubber w/ NH3 Red. Agent Steam Inj. & Low NOx Config. Exh. Duct Burner 87% Efficiency
Northern California Power	CA	GE Gas Turbine	25.8 MW	Apr-85	NOx 75 ppm	H2O Injection
Shell California Production	CA	Gas Turbine	22 MW	Apr-85	NOx 42 ppm @ 15% O2 35 lb/hr CO 10 PPMV @ 15% O2 22 lb/hr	H2O Inj. Proper Combustion
Southeast Energy, Inc.	CA	Gas Turbine	8.0 MMCF/D	Apr-86	NOx 8.29 lb/hr 0.023 lb/MMBTU	Scrubber w/ NH3 Red. Agent Steam Inj. & Low NOx Config. Exh. Duct Burner 87% Efficiency
Sunlaw/Industrial Park	CA	Gas Turbine	412.3 MMBTU/hr	Jun-85	NOx 9 PPMVD @ 15% O2 CO 10 PPMVD @ 15% O2	Scr. & Steam Inj., 80% Eff. Mfg Guarantee on CO Emissions
Union Cogeneration	CA	Gas Turbine w/ Duct Burner	16 MW	Jan-86	NOx 25 PPMV @ 15% O2 CO 8 lb/hr 29.2 TPY	H2O Injection & Scrubber Oxidizing Catalyst, 80% Efficiency
Willamette Industries	CA	GE Gas Turbine	230 MMBTU/hr	Apr-85	NOx 15 PPMVD @ 15% O2	H2O Inj. w/ Selective Cat. Red. 92% Efficiency

Table 4-2. LAER/BACT Decisions (Page 4 of 5)

Company Name	State	Unit Description	Capacity (Size)	Date of Permit	Emission Limit	Emission Control
Witco Chemical Corp.	CA	Gas Turbine	350 MMBTU/hr	Dec-84	NO_x 0.18 lb/MMBTU Oil 0.20 lb/MMBTU Gas	
		Duct Burner	111.6 MMBTU/hr		NO_x 0.12 lb/MMBTU	Gas Firing Only
AES Placerita, Inc.	CA	Turbine & Recovery Boiler	519 MMBTU/hr	Mar-86	NO_x 629 lb/d 7 PPMVD @ 15% O_2 CO 103 lb/d 2 PPMVD @ 15% O_2	H_2O Inj, Select. Cat. Red. 80% Efficiency
AES Placerita, Inc.	CA	Turbine & Recovery Boiler	530 MMBTU/hr	Jul-87	NO_x 340 lb/D 9 PPMVD @ 15% O_2	Steam Inj, Select. Cat. Red.
AES Placerita, Inc.	CA	Gas Turbine	530 MMBTU/hr	Jul-87	NO_x 289 lb/D 9 PPMVD @ 15% O_2	Steam Inj, Select. Cat. Red.
Alaska Electrical Generation	AK	Gas Turbine	80 MW	Mar-87	NO_x 75 PPMVD @ 15% O_2 CO 109 lb/SCF Fuel	H_2O Injection
Alaska Electrical Generation	AK	Gas Turbine	38 MW	Mar-85	NO_x 75 PPM @ 15% O_2	H_2O Injection
BAF Energy	CA	Turbine, Generator	887.2 MMBTU/hr	Jul-87	NO_x 9 PPM @ 15% O_2 30.1 lb/hr	Steam Injection, Scrubber 80% Efficiency
BAF Energy	CA	Auxiliary Boiler	150 MMBTU/hr	Oct-87	NO_x 17.4 lb/D 40 PPMVD @ 3% O_2 CO 63.6 lb/D 0.018 lb/MMBTU	Flue Gas Recirculation Low NO_x Burners Oxidation Catalyst
Champion International Corp.	TX	Gas Turbine	30.6 MW (1342 MMBTU/hr)	Mar-85	NO_x 720.34 TPY CO 70.08 TPY	Low NO_x Burners
Cogen Technologies	NJ	GE Gas Turbines	40 MW	Jun-87	NO_x 9.6 PPMVD @ 15% O_2 CO 50 PPMVD @ 15% O_2	H_2O Inject. & SCR, 95% Efficiency

Table 4-2. LAER/BACT Decisions (Page 5 of 5)

Company Name	State	Unit Description	Capacity (Size)	Date of Permit	Emission Limit	Emission Control
Combined Energy Resources	CA	Gas Turbine	2 MW	Feb-88	NOx 199 lb/hr	H2O Inj. & Scrubber, 81% Efficiency
Formosa Plastic Corp.	TX	GE Gas Turbine	38.4 MW	May-86	NOx 640 TPY CO 32.4 TPY	Steam Injection
Midland Cogeneration Venture	MI	Turbine	984.2 MMBTU/hr	Feb-88	NOx 42 PPMV @ 15% O2 CO 26 lb/hr	Steam Injection Turbine Design
		Duct Burner	249 MMBTU/hr		NOx 0.1 lb/MMBTU	Burner Design
Pacific Gas Transmission	OR	Gas Turbine	14000 HP	May-87	NOx 154 PPM 50 lb/hr CO 6 lb/hr 25 TPY	Combustion Control
Power Development Co.	CA	Gas Turbine	49 MMBTU/H	Jun-87	NOX 36 lb/D 9 PPMVD @ 15% O2	Scrubber & H2O Injection
San Joaquin Cogen Limited	CA	Gas Turbine	48.6 MW	Jun-87	NOx 250 lb/D 6 PPMVD @ 15% O2 CO 1326 lb/d 55 PPMVD @ 15% O2	Scrubber & H2O Injection 76% Efficiency Combustion Controls
TBG/Grumman	NY	Gas Turbine	16 MW	Mar-88	NOx 75 PPM + NSPS Corr. 0.2 lb/MMBTU CO 0.181 lb/MMBTU	H2O Inj. & Combustion Controls CO Catalyst
Texas Gas Transmission Corp.	KY	Gas Turbine	14300 HP	Feb-88	NOx 0.015 % by Volume	
Orlando Utilities Commission	FL	Gas Turbine	4 x 445 MMBTU/H	Sept-88	NOx 42 PPMDV Gas 65 PPMDV Oil CO 10 PPMMDV	Steam Injection Good Combustion
Anheuser-Busch	FL	Gas Turbine	95.7 MMBTU/hr	Apr-87	NOx 0.1 lb/MMBTU	

category of stationary source. This limitation, when applied to a modification, means the lowest achievable emissions rate for the new or modified emissions units within the stationary source. In no event shall the application of this term permit a proposed new modified stationary source to emit any pollutant in excess of the amount allowable under applicable new source standards of performance (40 CFR 51 Appendix S. II, A.18).

As noted from the discussion contained in Subsection 3.2.3, there is a regulatory distinction between LAER and BACT.

In Florida, the most recent permits have required wet injection for NO_x control. The emission limits were 42 ppm and 65 ppm (corrected to 15% O_2, dry conditions) respectively, for natural gas and fuel oil firing.

The hierarchy for NO_x control suggested by the existing and permitted facilities is as follows:

1. Selective Catalytic Reduction (SCR).
2. Wet Injection using standard or advanced combustor design.

The selected control level of SCR used for the BACT analysis was 9 ppm NO_x corrected to 15% dry conditions using natural gas. This level of control assumes 80% removal of NO_x by the SCR equipment with an input concentration of 42 ppm. For fuel oil firing, a control level of 14 ppm was used to account for fuel bound nitrogen. These levels of control are the most stringent being established as BACT. For wet injection, the advanced combustor design can limit NO_x to 25 ppm when firing natural gas and 42 ppm when firing fuel oil while the standard combustor design can limit No_x to 42 ppm when firing natural gas and 65 ppm when firing fuel oil.

4.3.1.2 Technology Description and Feasibility

SELECTIVE CATALYTIC REDUCTION (SCR)

SCR uses ammonia (NH_3) to react with NO_x in the gas stream under the presence of a catalyst. NH_3, which is diluted with air to about 5% by volume, is introduced into the gas stream at reaction temperatures between 600°F and 700°F. The reactions are as follows:

$$4NH_3 + 4NO = 4N_2 + 6H_2O$$

$$4NH_3 + 2NO_2 = 3N_2 + 6H_2O$$

SCR has mainly been installed at facilities located in nonattainment areas for NO_2 and mainly in California. While the operating experience has not been extensive, certain cost, technical and environmental considerations have surfaced. These considerations are summarized in Table 4-3.

The operating experience consists primarily of baseload natural gas fired installations either of cogeneration or combined cycle configuration; no simple cycle facilities have SCR. Exhaust gas temperatures of simple cycle combustion turbines are generally in the range of 1000°F, which exceeds the optimum range for SCR. While cooling could be accomplished through the introduction of ambient air, the increased volume of air would increase the catalyst size, and thus the cost, considerably. Water quenching is not feasible since the catalyst can be damaged and ammonium hydroxide, a corrosive, would be formed.

The use of fuel oil in SCR facilities has been limited since SCR catalysts are contaminated by sulfur containing fuels. For most fuel oil burning facilities, catalyst operation is discontinued, or the exhaust bypasses the SCR system. As presented in Table 4-3, ammonium bisulfate is formed by the reaction of NH_3 and SO_3. Experience at the United Airlines cogeneration facility using 0.05% fuel oil found catalyst contamination after 2,500 hours of operation. For this facility, the catalyst has been replaced three times and the recommended hours of operation by the manufacturer is now 500 hours.

Reported and permitted NO_x removal efficiencies of SCR range from 40 to 80%. Emission limiting standards with SCR are in the 9 ppm range for natural gas firing. However, two facilities have reported emission limits

Table 4-3. SCR Cost, Technical and Environmental Considerations for Combustion Turbines (Page 2 of 2)

Consideration	Description
Flow Control	The velocity through the catalyst must be within a range to assure satisfactory residence time.
ENVIRONMENTAL:	
Ammonia Slip	NH_3 slip, or NH_3 that passes unreacted through the catalyst and into the atmosphere can occur if: 1) too much ammonia is added, 2) the flow distribution is not uniform, 3) the velocity is not within the optimum range, or the proper temperature is not maintained.
Ammonia Bisulfate and Chloride Salts	Ammonium bisulfate and chloride salts can lead to increased corrosion. These usually occur when firing fuel oil. These compounds are emitted as particulates.
N_2O and Nitro-soamines formation	The mechanism under which these compounds form is not totally understood. Secondary impacts can occur.

of about 4.5 ppm. These emission limits were clearly determined to be LAER on machines using water injection below 42 ppm. For fuel oil firing, permitted NO_x emissions with SCR has ranged from 14 ppm to 42 ppm.

The available information suggests that SCR is a technically feasible alternative for the project. However, the following technical limitations exist:

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 demonstrated; technical, economic and environmental uncertainties would result.

WET INJECTION

The injection of water or steam in the combustion zone of turbines reduces the flame temperature with a decrease of NO_x emissions. The amount of NO_x reduction possible depends on the combustor design and the water to fuel ratio used. An increase in the water to fuel ratio will cause a concomitant decrease in NO_x emissions until flame instability occurs. At this point, operation of the turbine becomes inefficient and unreliable, and significant increases in products of incomplete combustion will be emitted, i.e., CO and VOC.

With standard combustion chamber design, there is a point where the amount of water or steam injected into the turbine seriously degrades its reliability and operational life. This generally occurs at NO_x emissions levels of about 65 ppmvd (with no heat rate adjustment) on oil and 42 ppmvd on natural gas. These NO_x emission levels can be achieved with little additional cost and with limited impact on reliability or power output over those costs required to comply with the NSPS.

Since the combustion turbine NSPS was last revised in 1982, combustion turbines have improved their tolerance to the water or steam necessary to control NO_x emissions below the NSPS requirement. Some manufactures have begun to market an improved low NO_x burner design. [These burners provide improved air/fuel mixing with water or steam injection result in reduced flame temperatures and concomitantly lower concentrations of NO_x as compared to a standard combustion chamber design (with water or steam injection).] These design improvements result in a NO_x emission rate of 25 ppmvd compared to 42 ppmvd with a standard combustor design. However there is the lack of operating experience with such designs and there is a significant increase in capital cost of the turbines. Also, approximately 25 gpm of additional demineralized water per turbine would be required for injection into the combustion chamber. The improved combustors would, however, increase CO concentrations relative to the standard combustor. Low NO_x burner designs are however, not available for several of the manufacturers being considered. Because of this and the lack of operating experience of those manufacturers with burners, low NO_x burner design are considered marginally feasible for the project.

Wet injection is a technically feasible alternative for the project. The application of this technology has the following limitations:

1. Wet injection can be accomplished until a condition of maximum moisturization occurs; this design condition depends on the combustor design but usually occurs at 42 ppm on natural gas and 65 ppm on fuel oil,

2. Wet injection will not substantially reduce NO_x formation due to fuel bound nitrogen, any emission limiting requirements must account for this effect, and

3. Wet injection will increase the emissions of CO and VOC depending on the water to fuel ratio.

For the BACT analysis, emissions with wet injection were considered to be 25 ppm and 42 ppm when firing natural gas and 42 ppm and 65 ppm when firing fuel oil (both corrected to 15% O_2 dry conditions). These emission levels are the most stringent being established as BACT.

4.3.1.3 Impact Analysis

A BACT determination requires an analysis of the economic, environmental, and energy impacts of the proposed and alternative control technologies (see 40 CFR 52.21(b)(12) and 17-2.100(25) and 17-2.500(5)(c) FAC). The analysis must be specific to the project, i.e., case-by-case. The economic and environmental impacts of the control technologies evaluated for NO_x are summarized in Table 4-4. The specific analyses are discussed below.

ECONOMIC

The total annualized cost for alternative NO_x control technologies range from $22,014,000 for SCR to $2,490,000 for wet injection to meet NSPS (Table 4-5). Incremental cost effectiveness for SCR was estimated to range from $8,250/ton NO_x removed for natural gas firing to $4,641/ton NO_x removed for fuel oil firing. This incremental cost is about a factor of four higher than the improved combustor design. Indeed, the incremental cost effectiveness was estimated to be over 25 times that of the standard combustor. For the improved combustor design the incremental cost effectiveness ranged from $1,626 to $915/ton of NO_x removed, which was about seven times or more higher than the standard combustor design. These costs reflect increased CO emissions. Assuming CO controls the incremental cost effectiveness would be $5,007/ton of NO_x removed when firing natural gas and $2,817/ton of NO_x removed when firing fuel oil. The incremental cost effectiveness for the standard combustor ranged from $176 to $504/ton of NO_x removed.

ENVIRONMENTAL

The maximum predicted impacts of the alternative technologies are all considerably below the PSD increment (i.e., 25 ug/m^3) and AAQS (i.e., 100 ug/m^3). Additional controls beyond NSPS improve air quality to less than about 20% of the PSD increment and about 5% of the AAQS.

Table 4-4. Summary of BACT Analysis

Pollutant	Control Option			Economic Impact		Environmental Impacts	
	Description	Fuel	Emissions (TPY)	Annualized Cost ($)	Incremental Cost Effectiveness ($/ton)	Impacts for Controlled Pollutant	Other Impacts
NOx	Water Injection with SCR to 9 ppm	Natural Gas	1,018	22,014,000	8,250	0.6 (Max. Annual)	Ammonia @ 10ppm
	Water Injection with SCR to 14 ppm	Fuel Oil	1,810	22,014,000	4,641	1.0 (Max. Annual)	Ammonia @ 10ppm Ammonium Bisulfate
	Improved Combustor Design to 25 ppm	Natural Gas	3,058	5,210,000 (10,868,000)	1,626 (5,007)	1.7 (Max. Annual)	Increase in CO & VOC; water use
	Improved Combustor Design to 42 ppm	Fuel Oil	5,431	5,210,000 (10,868,000)	915 (2,817)	3.0 (Max. Annual)	Increase in CO & VOC; water use
	Standard Combustor Design to 42 ppm	Natural Gas	4,729	2,490,000	176*	2.6 (Max. Annual)	Water use
	Standard Combustor Design to 65 ppm	Fuel Oil	8,405	2,490,000	504*	4.6 (Max. Annual)	Water use
CO	Catalytic Oxidation to 10 ppm	Natural Gas	685	5,658,000	2,663	10 (Max. 8 hr)	
	Combustion Techniques to 41 ppm	Natural Gas	2,810	--	--	39 (Max. 8 hr)	
SO2	0.20 % Sulfur Fuel	Fuel Oil	6,433	21,009,000	NA	25 (Max. 24 hr)	
	0.50 % Sulfur Fuel	Fuel Oil	16,083	--	--	63 (Max. 24 hr)	

* Based on an NSPS Emission Level of 98 ppm and an estimated annualized cost of $1,813,000.

Table 4-5. Annualized Cost Estimate for Alternative NOx Control Technology

Item	Basis	Standard Combustor & SCR	Improved Combustor	Standard Combustor
DIRECT COSTS (DC):				
Differential Turbine Costs		$ 1,800,000	$8,750,000	$1,800,000
SCR Reactor		$22,140,000	$0	$0
Ammonia Storage & Injection Equipment		$5,530,000	$0	$0
Water Treatment, Storage & Injection		$2,810,000	$4,240,000	$2,810,000
Balance of Plant		$1,160,000	$1,380,000	$1,060,000
Subtotal:		$33,440,000	$14,370,000	$5,670,000
CONTINGENCY:	10% of DC	$3,344,000	$1,437,000	$567,000
TOTAL CAPITAL COSTS (TCC):		$36,784,000	$15,807,000	$6,237,000
ESCALATION:		$5,429,318	$2,333,113	$920,581
TOTAL ESCALATED COST (TEC):		$42,213,318	$18,140,113	$7,157,581
SALES AND USE TAX:	6% of TEC	$2,532,799	$1,088,407	$429,455
SUBTOTAL:		$44,746,118	$19,228,520	$7,587,036
INDIRECT COSTS:	14.5% of Subtotal	$6,488,187	$2,788,135	$1,100,120
INTEREST DURING CONSTRUCTION:	10.45%	$5,353,985	$2,300,740	$907,808
INSTALLED COST:		$56,588,289	$24,317,396	$9,594,964
OPERATING COSTS:				
Operating & Maintenance*		$10,208,333	$986,111	$652,778
Ammonia		$ 1,305,556	$0	$0
Energy		$ 2,125,000	$625,000	$416,667
ANNUAL OPERATING COST:		$13,638,889	$1,611,111	$1,069,444
FIXED CHARGES ON CAPITAL:	14.8% of Installed Cost	$ 8,375,067	$3,598,975	$1,420,055
TOTAL LEVELIZED ANNUAL COST:		$22,013,956	$5,210,086	$2,489,499

* Includes Catalyst Replacement

Additional air quality impacts would occur with the installation of SCR. Emissions of ammonia, ammonium sulfates, such as ammonium bisulfate, and chloride salts would occur. Ammonia would be emitted at a concentration of at least about 10 ppm based on previous experience; previous permit conditions have selected this level. For a 660 MW plant, ammonia emissions would be about 400 ton/year. However, ammonia emissions could be five times this level since actual operating experience has found ammonia slippage rates as high as 50 ppm.

The replacement of SCR catalyst will create additional economic and environmental impacts since such catalyst, e.g. vanadium pentoxide, are listed as hazardous chemical wastes under RCRA regulations (40 CFR 261).

ENERGY

Energy penalties will occur with all control alternatives evaluated. The most significant is with SCR would reduce the output of the combustion turbine by about 0.1% over wet injection. This would amount to about a 5,800,000 kw/hr loss in potential generation/year.

4.3.1.4 Proposed BACT and Rationale

The proposed BACT for the Hardee Power Station is wet injection using standard combustor design. The NO_x emissions levels using standard combustor with wet injection would be 42 ppm when firing natural gas and 65 ppm when firing fuel oil. This alternative control is proposed for the following reasons:

1. SCR was rejected based on technical economic and environmental grounds. Operation of SCR during simple cycle CT operation has not been demonstrated since the temperature range of the exhaust exceeds operational requirements for optimum catalytic reaction. Fuel oil firing when operating SCR would cause operating problems and result in catalyst poisoning. The estimated total and incremental costs exceed $2,000 and $5,000/tons of NO_x removed, respectively. These costs are over an order of magnitude more costly than the proposed BACT levels. Additional environmental

impacts would result from SCR operation including emissions of ammonia and ammonium bisulfates, and the generation of hazardous waste, i.e., spent catalyst replacement.

2. The improved combustor design is rejected based on technical economic and environmental reasons. Not all manufacturers offer improved combustor designs. For those who do, an economic penalty would result: the annualized cost of such systems is over twice that of the standard combustor design. In addition, these improved combustor designs have not been demonstrated to achieve the reliability and maintenance requirements as standard designs. Environmental impacts would also result including increases in CO and VOC emissions and water consumption. Control of CO and VOC emissions greatly increase the cost of the advanced combustor. The cost effectiveness would exceed $2,500/ton of NO_x removed. Water use has been estimated to increase 25 gpm per turbine or about 130,000 gpd more than a standard combustor design.

3. The proposed BACT provides the least costly alternative and results in the maximum environmental impacts of less than 20% of the PSD increments and 5% of the AAQS. Wet injection at the proposed emissions levels has been adopted as BACT previously and manufacturers have guaranteed this level.

4.3.2 Carbon Monoxide (CO)

4.3.2.1 Emission Control Hierarchy

CO emissions are a result of incomplete or partial combustion of fossil fuel. Combustion design and catalytic oxidation are the control alternatives that are viable for the project.

Combustion design is the more prevalent control technique used in combustion turbines. Sufficient time, temperature and turbulence is required within the combustion zone to minimize the emissions of CO. As such, combustion efficiency is dependent upon combustor design and, in NO_x control systems, the amount of water or steam injected in the combustion zone. For the combustion turbines being evaluated, CO emissions range from 10 ppm to 41 ppm, corrected to 15% O_2 dry conditions.

Catalytic oxidation is a post combustion control that has been installed where CO nonattainment regulations have required CO reduction due to increases caused by wet injection. These LAER installations typically have CO limits in the 10 ppm range (corrected to 15% O_2 and dry conditions).

4.3.2.2 Technology Description

Oxidation catalyst control CO emissions by allowing unburned CO to react with oxygen at the surface of a precious metal catalyst such as a platinum coated surface. Combustion of CO starts at about 300°F with efficiencies above 90% occurring at temperatures above 600°F. Catalytic oxidation occurs at temperatures 50% lower than that of thermal oxidation which reduces the amount of thermal energy required. For combustion turbine and HRSG combinations, the oxidation catalyst can be located directly after the turbine or in the HRSG. Catalyst size depends upon the exhaust flow, temperature and desired efficiency. The existing gas turbine applications have been limited to smaller cogeneration facilities burning natural gas. Controlled CO levels of 10 ppm have generally been established as BACT.

Oxidation catalysts have not been used on fuel oil fired combustion turbines or combined cycle facilities. The use of sulfur containing fuels in a system with oxidation catalyst would result in an increase of SO_3 emissions and concomitant corrosive effects to the back end of the HRSG and stack. In addition, trace metals in the fuel would result in catalyst poisoning during prolonged periods of operation.

Since the facility would likely require numerous start-ups, variations in exhaust conditions would influence catalyst life and performance. Very little technical data exist to demonstrate the effect of such cycling. The size and fuel requirements for the project would suggest rejection of catalytic oxidation as a technically feasible alternative. However, continuous operation using natural gas is technically feasible and therefore evaluated or an alternative BACT technology.

Combustion design is dependent upon the manufacturer's operating specifications which include air to fuel ratio and the amount of water injected. All combustion turbines presently being considered have designs to optimize combustion efficiency and minimize CO emissions.

4.3.2.3 Impact Analysis

ECONOMIC

The estimated annualized cost of a CO oxidation catalyst is $5,658,000 (Table 4-6) with a total cost effectiveness of $2,663/ton of CO removed. The latter assumes that the "worst-case" emissions will be in the range of 41 ppm corrected to 15% O_2 dry conditions. At a CO emission of 25 ppm, the cost effectiveness would exceed $5,000/ton of pollutant removed. No costs are associated with combustion techniques since they are inherent to the process.

ENVIRONMENTAL

The air quality impacts of both techniques are below the significant impact levels for CO. Therefore, no environmental benefit would be realized by the installation of a CO catalyst.

ENERGY

An energy penalty would result from the pressure drop across the catalyst bed. A pressure drop of about 1 1/2 to 2 1/2 water gauge would be expected. At a catalyst back pressure of about 2 in, an energy penalty of about 4,000,000 kw-hr/year would result.

4.3.2.4 Proposed BACT and Rationale

Combustion design is proposed as BACT due to the technical and economic consequences of installing catalytic oxidation. Catalytic oxidation is not

Table 4-6. Annualized Cost Estimate for CO Catalyst

Item	Basis	Cost
DIRECT COSTS (DC):		
Catalyst	Manufacturer	$7,644,000
Installation	45% of Catalyst	$3,439,800
Subtotal:		$11,083,800
CONTINGENCY:	10% of DC	$1,108,380
TOTAL CAPITAL COSTS (TCC):		$2,032,030
ESCALATION:		$1,799,568
TOTAL ESCALATED COST (TEC):		$13,831,651
SALES AND USE TAX:	6% of TEC	$839,504
SUBTOTAL:		$14,831,253
INDIRECT COSTS:	14.5% of Subtotal	$2,150,532
INTEREST DURING CONSTRUCTION:	10.45% of Subtotal	$1,549,866
INSTALLED COST:		$18,531,651
OPERATING COSTS:		
Labor	1 man-year	$270,000
Catalyst Replacement*	Manufacturer	$2,400,000
Miscellaneous Parts	1% of Installed Cost	$185,316
Energy Penalty	Estimated	$60,000
ANNUAL OPERATING COST:		$2,915,316
FIXED CHARGES ON CAPITAL:	14.8% of Installed Cost	$2,742,684
TOTAL LEVELIZED ANNUAL COST:		$5,658,000

* 2-year replacement interval on fuel oil

considered feasible, not withstanding the lack of environmental benefit, for the following reasons:

1. Catalytic oxidation has not been demonstrated on cycling combustion turbines or those using fuel oil; and
2. The economic impacts are significant, i.e. annualized cost of \$5,658,000 with a likely cost effectiveness of over \$5,000/tons of pollutant removed.

4.3.3 Sulfur Dioxide (SO_2)

4.3.2.1 Emission control Hierarchy

Sulfur dioxide (SO_2) emissions are a result of the oxidation of sulfur in fossil fuel and can be minimized by reducing the sulfur content in fuel or through applying post combustion removed techniques. For combustion turbines, the use of low sulfur fuels is the only demonstrated control technology determined to be technically feasible. Post combustion techniques, such as flue gas desulfurization (FGD) have not been applied to combustion turbines.

FGD systems have been applied to oil and coal-fired steam electric power plants. However, the relative gas volume for such facilities is significantly less than that for combustion turbines (i.e., about 2 to 3 times) and the resultant SO_2 concentration is considerably more. While the former factor will influence the cost of FGD, the later poses significant technological constraints to removing SO_2.

The BACT/LAER clearinghouse documents (1985, 1986b, 1987c, 1988c) show fuel sulfur contents from 0.8% to less than 0.2%. The lowest sulfur containing fuels were required in California where LAER decisions dictate more stringent standards. Furthermore, such requirements generally limited fuel oil use for backup or emergency purposes only. For the Hardee Power Station the only technically feasible control technology for SO_2 is therefore low sulfur fuel use. The use of natural gas will clearly minimize SO_2 emission. SO_2 emissions from distillate fuel can be minimized by specification of a lower sulfur content fuel, or blending of a lower sulfur content fuel, such as No. 1 fuel oil or kerosene, with No. 2 fuel oil. To reduce the uncertainties of supplier reliability, the blending of kerosene was selected as an alternative control technology of the project. A sulfur content of 0.2% was selected as the BACT level since it is near the lowest of sulfur contents contained in the BACT clearinghouse documents.

4.3.3.2 Technology Description

The sulfur content of No. 2 fuel oil will have a maximum sulfur content of 0.5% with a nominal average of 0.3%. For the purposes of the analysis the maximum sulfur content was assumed. Kerosene has a sulfur content of 0.05%.

To obtain an average sulfur content of 0.2%, No. 2 fuel oil and Kerosene would have to be blended in a ration of about 1 to 2. Blending would require a separate storage tank, transfer pumps, mixing tank and mixing equipment.

4.3.3.3 Impact Analysis

ECONOMIC

The total annualized cost for achieving a maximum 0.2% sulfur fuel was estimated at $21,009,000 (Table 4-7). The incremental cost of $2,177/ton of pollutant removed reflects the assumption that the No.2 fuel oil received would be 0.5%. At the more nominal sulfur content of 0.3% for No. 2 fuel oil the cost effectiveness would be $6,531/ton of pollutant removed. In addition, the cost effectiveness would substantially increase as the percentage of fuel oil decreases. As discussed previously primary fuel for the project is natural gas.

ENVIRONMENTAL

Both alternatives are less than the PSD increment and AAQS. Substantial air quality benefits are not expected given the primary use of natural gas and the fact that the maximum SO_2 concentrations were predicted to occur at the property boundary.

Table 4-7. Annualized Cost Estimate for SO_2 Control

Item	Basis	Cost
DIRECT COSTS (DC):		
Oil Tank & Mixers	Estimate	$5,000,000
Installation	45% of Equipment	$2,250,000
Subtotal:		$7,250,000
CONTINGENCY:	10% of DC	$725,000
TOTAL CAPITAL COSTS (TCC):		$7,975,000
ESCALATION:		$1,177,110
TOTAL ESCALATED COST (TEC):		$9,152,110
SALES AND USE TAX:	6% of TEC	$549,127
SUBTOTAL:		$9,701,237
INDIRECT COSTS:	14.5% of Subtotal	$1,406,679
INTEREST DURING CONSTRUCTION:	10.45% of Subtotal	$1,013,779
INSTALLED COST:		$12,121,695
OPERATING COSTS:		
Labor	1 man-year	$45,000
Fuel Cost	$0.07/gallon differential	$19,049,008
Miscellaneous Parts	1% of Installed Cost	$121,217
ANNUAL OPERATING COST:		$19,215,225
FIXED CHARGES ON CAPITAL:	14.8% of Installed Cost	$1,794,011
TOTAL LEVELIZED ANNUAL COST:		$21,009,236

* 2-year replacement interval on fuel oil

ENERGY

No substantial energy penalties were assumed to occur with the blending of kerosene with No. 2 fuel oil.

4.3.3.4 Proposed BACT and Rationale

The proposed BACT for the Hardee Power Station is the use of natural gas and No. 2 fuel oil with a maximum sulfur content 0.5%. The basis for this control alternative are:

1. The blending of Kerosene is not economically feasible. Indeed, it is uncertain if the quantities of kerosene required to be blended with No. 2 fuel oil could be obtained.
2. The primary fuel for the project is natural gas which would increase the relative cost effectiveness of blending kerosene with No. 2 fuel oil.

4.3.4 <u>Particulate Emissions</u>

The emission of particulates from the combustion turbine facility are a result of some incomplete combustion that may occur and of having some trace solids in the fuel, especially fuel oil. The design of the combustion turbines will insure that particulate emissions will be minimized by combustion controls and the use of clean fuels. A review of the USEPA's BACT/LAER Clearinghouse documents did not reveal any post combustion particulate control technologies being used on gas/oil fueled combustion turbines. The natural gas and distillate fuel oil to be used in the proposed combustion turbines will only contain trace quantities of particulate. Therefore, the fuel and combustion design will ensure maximum possible fuel combustion and are the proposed BACT for total suspended particulate, and particulate matter smaller than 10 microns (PM10). Indeed, the maximum particulate emissions will be of less concentration than that normally specified for fabric filter designs; i.e., the grain loading of the maximum particulate emissions (57 lbs/yr) is less than 0.01 grains/SCF which a typical design specification for a baghouse.

4.3.5 Other Criteria and Non-Regulated Pollutants Emissions

Emission estimates indicate that significance levels are exceeded for VOC, sulfuric acid mist, mercury beryllium and arsenic, requiring PSD review (including BACT) for these pollutants.

There are no technically feasible methods for controlling the emission of these pollutants from combustion turbines, other than complete combustion of the fuel, and the inherent quality of the fuel (see Section 4.3.3 and 4.3.4). Sulfuric acid mist emissions are a direct function of the sulfur content of the fuel. BACT regarding mercury beryllium, and arsenic is the inherent quality of the fuel.

For the non-regulated pollutants, none of the control technologies evaluated would reduce these concentrations. The air quality impacts of the pollutants are expected to be significantly below any levels that would cause health effects.

5.0 AIR QUALITY ANALYSIS

5.1 GENERAL MONITORING REQUIREMENTS

The CAA requires that an air quality analysis be conducted for each pollutant subject to regulation under the act before a major stationary source or major modification is constructed. This analysis may be performed through the use of modeling and/or monitoring the air quality. The use of monitoring data refers to either the use of representative air quality data from existing monitoring stations or establishing a monitoring network to monitor existing air quality. Monitoring must be conducted for a period up to 1 year prior to submission of a construction permit application. In addition to establishing existing air quality, the air quality data are useful for determining background concentrations (i.e., concentrations from sources not considered in the modeling). The background concentrations can be added to the concentrations predicted for the sources considered in the modeling to estimate total air quality impacts. These total concentrations are then evaluated to determine compliance with the AAQS.

For the criteria pollutants, continuous air quality monitoring data must be used to establish existing air quality concentrations in the vicinity of the proposed source or modification. However, preconstruction monitoring data will generally not be required if the ambient air quality concentration before construction is less than the de minimis impact monitoring concentrations, (refer to Table 3-3 for de minimis impact levels). Also, if the maximum predicted impact of the source or modification is less than the de minimis impact monitoring concentrations, the source generally would be exempt from preconstruction monitoring.

For noncriteria pollutants, USEPA recommends that an analysis based on the air quality modeling should generally be used instead of monitoring data. The permit-granting authority has discretion in requiring preconstruction monitoring data when:

1. The state has an air quality standard for the noncriteria pollutant and emissions from the source or modification pose a threat to the standard;

2. The reliability of emission data used as input to modeling existing sources is highly questionable; or
3. Air quality models have not been validated or may be suspect for certain situations, such as complex terrain or building downwash conditions.

However, before a permit granting authority requires preconstruction monitoring, USEPA recommends that an acceptable measurement method approved by USEPA should be available and the maximum concentrations due to the major source or major modification are predicted to be above the significant monitoring concentrations.

The USEPA "Ambient Monitoring Guidelines for Prevention of Significant Deterioration" (PSD) (USEPA, 1987a) sets forth guidelines for preconstruction monitoring. The guidelines allow the use of existing air quality data in lieu of additional air monitoring, if the existing data are "representative." The criteria used in determining the representativeness of data are: 1) monitor location, 2) quality of data, and 3) currentness of data.

For the first criteria, monitor location, the existing monitoring data should be representative of three types of areas: (1) the location(s) of maximum concentration increase from the proposed source or modification, (2) the location(s) of the maximum air pollutant concentration from existing sources, and (3) the location(s) of the maximum impact area, i.e., where the maximum pollutant concentration hypothetically would occur based on the combined effect of existing sources and the proposed new source or modification. The locations and size of the three types of areas are determined through the application of air quality models. The areas of maximum concentration or maximum combined impact vary in size and are influenced by factors such as the size and relative distribution of ground level and elevated sources, the averaging times of concern, and the distances between impact areas, and contributing sources.

5.2 PROJECT MONITORING APPLICABILITY

As determined by the source applicability analysis described in Section 3.4, an ambient monitoring analysis is required by PSD regulations for SO_2, NO_2, PM, CO, VOC, sulfuric acid mist, Hg, Be and As. However, dispersion modeling analysis demonstrates that impacts due to the emissions from the proposed facility are less than the de minimis impact levels established for NO_2, PM, CO, Hg, and Be, but above the de minimis level for SO_2. The proposed emissions of VOC, sulfuric acid mist and arsenic are above the significant emission rates. However, for sulfuric acid mist and arsenic, no de minimis levels have been established for these pollutants because acceptable monitoring methods have not been developed. Therefore, monitoring is not required for sulfuric acid mist or arsenic.

For SO_2, the Florida DER has approved an exemption from PSD ambient air quality monitoring for this project. The request was made in the Environmental Licensing Plan of Study (KBN, 1988) with FDER's recommendation for monitoring exemption in September 1988 (FDER, 1988). The exemption is appropriate because:

1. The site is not located near (i.e., within 10 km) any major sources of pollutant emissions;
2. Background concentrations are expected to be low and near the PSD monitoring de minimis impact levels; and
3. Data from existing monitors will provide conservative background concentrations because these sites are located in more industrial areas than the project site.

Because of the rural area and minimal amount of air pollution sources in Hardee County, the Florida DER does not operate any monitoring stations in the county. Existing air quality data were obtained from monitoring stations operated by the Florida DER in Polk County, which has monitoring stations closest to the proposed project site. The closest ambient air monitoring stations to the proposed project site that measure SO_2 concentrations are located in Nichols, about 25 km north-northwest of the site, and in Lakeland, about 50 km north of the site. Because these monitors are located in urban areas, and/or in proximity (i.e., within 10 km) of major sources, the observed concentrations are considered to be higher than those expected to occur at the proposed facility. A more detailed discussion about the monitoring data collected at these stations is presented in Section 6.6 on background concentrations.

Preconstruction monitoring review is required for O_3 concentrations because the maximum potential VOC emissions from the proposed plant are greater than 100 TPY. The proposed facility is located in Hardee County which is an attainment area for O_3 concentrations. As discussed earlier, the proposed facility is located in a rural area with minimal industrial development (i.e., lack of major VOC emission sources) within 15 km of the site.

A summary of the nearest monitoring stations to the proposed facility that measure O_3 concentrations is presented in Table 5-1. These stations are operated by the FDER or are part of the Florida Acid Deposition Monitoring Program (FADMP) (ESE, 1988). These sites are located between 50 and 79 km in directions from the east clockwise through west from the site. Except for the FDER station in Hillsborough County, all stations have measured maximum 1-hour average O_3 concentrations that are less than 1-hour AAQS of 0.12 ppm. The Hillsborough County monitoring station has measured 1-hour concentration greater than the AAQS but this station is located in an urban area near and within the vicinity of major VOC emission sources. Data measured at this station are not considered representative of the proposed facility's site.

Therefore, based on the modeling results and the use of existing monitoring data, an exemption from preconstruction monitoring for all pollutants is appropriate.

Table 5-1. Ozone Concentration Measured in 1987 at FDER and FADMP Monitoring Sites Near the Proposed Hardee Power Station

County/Location	Identification Number	UTM Coordinate (km)* East	North	Number of Observations	1-Hour Concentration (ppm) First	Second
FDER Sites						
Manatee/Brandenton	0320-002-G002	340.0	3041.9	7839	0.115	0.105
		(257°, 66.6 km)				
Sarasota/Sarasota	4080-002-G01	350.0	3019.8	4907	0.094	0.090
		(236°, 66.5 km)				
Sarasota/Sarasota	4100-012-G01	371.7	3028.9	8054	0.093	0.092
		(229°, 43.7 km)				
Hillsborough/ Hillsborough Bay	1800-081-G03	355.2	3068.8	8593	0.171	0.151
		(283°, 50.8 km)				
FADMP Site						
Highlands/Archbold	1780-013-9A	465.2	3006.5	7773	0.110	0.091
		(130°, 79.0 km)				

* Relative location from the proposed plant given in parentheses.

Source: FDER, 1988.
ESE, 1988.

6.0 AIR QUALITY MODELING APPROACH

6.1 GENERAL MODELING APPROACH

The general modeling approach followed USEPA and FDER modeling guidelines for determining compliance with AAQS and PSD increments. In general, when model predictions are used to determine compliance with AAQS and PSD increments, current policies stipulate that the highest annual average and highest, second-highest short-term (i.e., 24 hours or less) concentrations can be compared to the applicable standard when 5 years of meteorological data are used. The highest, second-highest concentration is calculated for a receptor field by:

1. Eliminating the highest concentration predicted at each receptor,
2. Identifying the second-highest concentration at each receptor, and
3. Selecting the highest concentration among these second-highest concentrations.

This approach is consistent with the air quality standards, which permit a short-term average concentration to be exceeded once per year at each receptor.

To develop the maximum short-term concentrations for the proposed facility, the general modeling approach was divided into screening and refined phases to reduce the computation time required to perform the modeling analysis. The basic difference between the two phases is the receptor grid used when predicting concentrations, the number of emission points, and the number of meteorological periods evaluated. In general, concentrations for the screening phase were predicted using a coarse receptor grid, limited number of major sources, and a 5-year meteorological record.

After a final list of highest, second-highest short-term concentrations was developed, the refined phase of the analysis was conducted by predicting concentrations for a refined receptor grid centered on the receptor at which the highest, second-highest concentration from the screening phase was produced. The air dispersion model was executed for the meteorological periods during which both the highest and second-highest concentrations were predicted to occur at that receptor, based on the screening phase results. This approach was used to ensure that valid highest, second-highest concentrations were obtained. More detailed descriptions of the emission inventory and receptor grids used in the screening and refined phases of the analysis are presented in the following sections.

6.2 MODEL SELECTION

The selection of a model was based on its applicability to simulate impacts in areas surrounding the proposed facility. Within 3.0 km of the proposed facility, the terrain can be described as simple, i.e., flat to gently rolling. As defined in the USEPA modeling guidelines, simple terrain is considered to be an area where the terrain features are all lower in elevation than the top of the stack(s) under evaluation. Beyond 3.0 km and within 50 km of the proposed facility's site, the terrain has maximum elevations of 50 ft above ground elevation at the facility. These areas are also considered to be simple since the stacks being modeled are greater than the terrain elevation. Therefore, a simple terrain model was used to predict maximum ground-level concentrations.

The ISC dispersion model (USEPA, 1988a) was used to evaluate the pollutant emissions from proposed facility and existing major facilities. This model is contained in USEPA's User's Network for Applied Modeling of Air Pollution (UNAMAP), Version 6 (USEPA, 1988b). The ISC model is applicable to sources located in either flat or rolling terrain where terrain heights do not exceed stack heights.

The ISC model consists of two sets of computer codes which are used to calculate short- and long-term ground level concentrations. The main differences between the two codes are the input format of the meteorological data and the method of estimating the plume's horizontal dispersion.

The first model code, the ISCST model, is an extended version of the single-source (CRSTER) model (USEPA, 1977). The ISCST model is designed to calculate hourly concentrations based on hourly meteorological parameters (i.e., wind direction, wind speed, atmospheric stability, ambient temperature, and mixing heights). The hourly concentrations are processed into non-overlapping, short-term and annual averaging periods. For example, a 24-hour average concentration is based on twenty-four 1-hour averages calculated from midnight to midnight of each day. For each short-term averaging period selected, the highest and second-highest average concentrations are calculated for each receptor. As an option, a table of the 50 highest concentrations over the entire field of receptors can be produced.

The second model code of the ISC model is the ISC long-term (ISCLT) model, which is an extension of the Air Quality Display Model (AQDM) and the Climatological Dispersion Model (CDM). The ISCLT model uses joint frequencies of wind direction, wind speed, and atmospheric stability to calculate seasonal and/or annual average ground-level concentrations. Because the input wind directions are for 16 sectors, with each sector defined as 22.5 degrees, the model calculates concentrations by assuming that the pollutant is uniformly distributed in the horizontal plane within a 22.5-degree sector.

In this analysis, the ISCST model was used to calculate both short-term and annual average concentrations because these concentrations are readily obtainable from the model output.

Major features of the ISCST model are presented in Table 6-1. Concentrations due to stack and volume sources are calculated by the ISCST model using the steady-state Gaussian plume equation for a continuous source. The area source equation in the ISCST model is based on the equation for a continuous and finite crosswind line source. The ISC model has rural and urban options which affect the wind speed profile exponent law, dispersion rates, and mixing-height formulations used in calculating ground level concentrations. The criteria used to determine when the rural or urban mode is appropriate are based on land use near the proposed plant's

Table 6-1. Major Features of the ISCST Model

ISCST Model Features
o Polar or Cartesian coordinate systems for receptor locations
o Rural or one of three urban options which affect wind speed profile exponent, dispersion rates, and mixing height calculations
o Plume rise due to momentum and buoyancy as a function of downwind distance for stack emissions (Briggs, 1969, 1971, 1972, and 1975)
o Procedures suggested by Huber and Snyder (1976); Huber (1977); and Schulmann and Hanna (1986) and Schulmann and Scire (1980) for evaluating building wake effects
o Procedures suggested by Briggs (1974) for evaluating stack-tip downwash
o Separation of multiple point sources
o Consideration of the effects of gravitational settling and dry deposition on ambient particulate concentrations
o Capability of simulating point, line, volume and area sources
o Capability to calculate dry deposition
o Variation with height of wind speed (wind speed-profile exponent law)
o Concentration estimates for 1-hour to annual average
o Terrain-adjustment procedures for elevated terrain including a terrain truncation algorithm
o Receptors located above local terrain, i.e., "flagpole" receptors
o Consideration of time-dependent exponential decay of pollutants
o The method of Pasquill (1976) to account for buoyancy-induced dispersion
o A regulatory default option to set various model options and parameters to EPA recommended values (see text for regulatory options used)
o Procedure for calm-wind processing

Source: USEPA, 1988a

surroundings (Auer, 1978). If the land use is classified as heavy industrial, light-moderate industrial, commercial, or compact residential for more than 50% of the area within a 3 km radius circle centered on the proposed source, the urban option should be selected. Otherwise, the rural option is more appropriate.

For modeling analyses that will undergo regulatory review, such as PSD permit applications, the following model features are recommended by USEPA (1987a) and are referred to as the regulatory options in the ISCST model:

1. Final plume rise at all receptor locations,
2. Stack-tip downwash,
3. Buoyancy-induced dispersion,
4. Default wind speed profile coefficients for rural or urban option,
5. Default vertical potential temperature gradients,
6. Calm wind processing, and
7. Reducing calculated SO_2 concentrations in urban areas by using a decay half-life of 4 hours (i.e., reduce the SO_2 concentration emitted by 50% for every 4 hours of plume travel time).

In this analysis, the USEPA regulatory options were used to address maximum impacts. Based on a review of the land use around the facility and discussions with the FDER, the rural mode was selected because of the lack of residential, industrial and commercial development within 3 km the proposed facility site.

6.3 METEOROLOGICAL DATA

Meteorological data used in the ISCST 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) stations at Tampa International Airport and Ruskin, respectively. The 5-year period of meteorological data was from 1982 through 1986. The NWS station in Tampa, located approximately 67 km to the west-northwest of the proposed site, was selected for use in the study because it is the closest primary weather station to the study area with similar surrounding topographical feature. This station also has the most readily available and complete database which is representative of the plant site. In addition, FDER has requested the use of this meteorological data. The surface observations included wind direction, wind speed, temperature, cloud cover, and cloud ceiling. The wind speed, cloud cover, and cloud ceiling values were used in the ISCST meteorological preprocessor program to determine atmospheric stability using the Turner stability scheme. Based on the temperature measurements at morning and afternoon, mixing heights were calculated with the radiosonde data at Ruskin using the Holzworth approach (1972). Hourly mixing heights were derived from the morning and afternoon mixing heights using the interpolation method developed by USEPA (Holzworth, 1972). The hourly surface data and mixing heights were used to develop a sequential series of hourly meteorological data (i.e., wind direction, wind speed, temperature, stability, and mixing heights). Because the observed hourly wind directions were classified into one of thirty-six 10-degree sectors, the wind directions were randomized within each sector using a USEPA preprocessing program to account for the expected variability in air flow.

6.4 EMISSION INVENTORY

Preliminary modeling indicated that the proposed facility's impacts could be above the significant impact levels for SO_2, NO_2 and PM at distances of approximately 50, 50, and 10 km, respectively, from the facility. Therefore, the emission inventories for those pollutants were developed from available databases, such as FDER's Air Pollution Inventory System (APIS) and previous studies performed by KBN. The initial step involved requesting and receiving from FDER the listing of all facilities within 100 km square centered on the proposed site. From this listing, a total of 305 facilities were identified. Using current data from APIS for each facility within the 100 km square, there were 32 facilities that had maximum allowable SO_2 emissions greater than 100 TPY and were within 50 km of the proposed facility; 19 facilities that had maximum allowable NO_2 emissions greater than 100 TPY and were within 50 km of the proposed facility; there were no facilities that had maximum allowable PM emissions greater than 100 TPY within 10 km of the proposed facility. However, within 50 km of the proposed facility, there were 42 facilities that had maximum allowable PM emissions greater than 100 TPY. Listings of the sources in the inventory with maximum allowable SO_2, NO_2, and PM emissions greater than 100 TPY and within 50 km of the proposed facility are presented in Tables 6-2 through 6-4, respectively.

Each facility was screened to determine the probability of interaction with the proposed facility. The screening technique is the "Screening Threshold" method, developed by the North Carolina Department of Natural Resources and Community Development, and approved for use by the USEPA and FDER. The method is designed to objectively eliminate from the emission inventory those sources which are not likely to have a significant interaction with the source undergoing evaluation. In general, sources that should be considered in the modeling analyses are those with emissions greater than Q (in TPY) which is calculated by the following criteria:

$$Q = 20 \times D$$

where D is the distance (km) from the source to the source undergoing review.

A listing of the emission sources and associated Q are presented in Tables 6-5 through 6-7. The sources with maximum allowable emissions which are below the calculated "screening threshold" emissions were eliminated from further consideration in the modeling analysis. A total of 22, 19, and 42 facilities (excluding the proposed facility) were included in the modeling analysis for SO_2, NO_2, and PM emissions.

In order to reduce the model computation time but effectively model sources that are most likely to interact with the proposed facility, modeling was performed in screening and refined phases. In the screening phase, only those sources with emissions above a certain threshold, based on the source's distance from the proposed facility, were modeled. The following

Table 6-2. SO2 Sources (>100 TPY) Within 50 km of Proposed Hardee Power Station

Facility	UTM Coordinates (km) East	UTM Coordinates (km) North	Relative Location (km) To Proposed Site X	Relative Location (km) To Proposed Site Y	Distance From Proposed Site (km)	Direction From Proposed Site (degree)	Maximum SO2 * Emissions (TPY)
Gardinier	415.3	3063.3	10.5	5.9	12.0	61	1,173
Imperial Phosphate	404.8	3069.5	0.0	12.1	12.1	0	275
Agrico Chemical Co. (S. Pierce)	407.5	3071.5	2.7	14.1	14.4	11	4,557
Mobil Oil Big Four Mine	394.7	3069.6	-10.1	12.2	15.8	320	569
U.S. Agri-Chemicals	416.0	3069.0	11.2	11.6	16.1	44	2,933
Wachula City Power Plant	418.4	3047.0	13.6	-10.4	17.1	127	180
IMC Fort Lonesome	389.5	3067.9	-15.3	10.5	18.6	304	1,714
Agrico Chemical Co. (Pierce)	403.7	3079.0	-1.1	21.6	21.6	357	417
Mobil-Electrophosphate Division+	405.6	3080.0	0.8	22.6	22.6	2	1,428
Farmland Industries	409.5	3080.1	4.7	22.7	23.2	12	3,692
IMC	396.7	3079.4	-8.1	22.0	23.4	340	10,251
IMC/Noralyn Mine Road	414.7	3080.3	9.9	22.9	24.9	23	505
C.F. Industries	408.4	3082.4	3.6	25.0	25.3	8	8,443
Kaplan Industries	418.3	3079.3	13.5	21.9	25.7	32	385
American Orange Corp.	429.8	3047.3	25.0	-10.1	27.0	112	198
Conserv. Chemicals	398.7	3084.2	-6.1	26.8	27.5	347	1,597
Royster Co.	406.8	3085.1	2.0	27.7	27.8	4	1,283
Mobil Chemical Co./Nichols	398.4	3085.3	-6.4	27.9	28.6	347	1,516
IMC/Praire	402.9	3087.0	-1.9	29.6	29.7	356	137
W.R. Grace & Co.	409.8	3086.7	5.0	29.3	29.7	10	8,186
U.S. Agri-Chemicals	413.2	3086.3	8.4	28.9	30.1	16	1,575
FPL Manatee	367.2	3054.1	-37.6	-3.3	37.7	265	85,305
Tricil Recovery Services	422.7	3091.9	17.9	34.5	38.9	27	240
Consolidated Minerals	393.8	3096.3	-11.0	38.9	40.4	344	3,302
Teco Big Bend	361.9	3075.0	-42.9	17.6	46.4	292	371,733
Citrus World	441.0	3087.3	36.2	29.9	47.0	50	597
Columbus Company	361.9	3077.8	-42.9	20.4	47.5	295	167
Gardinier	362.9	3082.2	-41.9	24.8	48.7	301	5,181
Lakeland City Power	409.0	3106.2	4.2	48.8	49.0	5	4,014
Lakeland City Power	409.2	3106.2	4.4	48.8	49.0	5	30,176
Adams Packing	421.7	3104.2	16.9	46.8	49.8	20	172
						Total	551,901

* Maximum facility emissions from APIS, or other available information on facility.

Table 6-3. NO2 Sources (>100 TPY) Within 50 km of Proposed Hardee Power Station

Facility	UTM Coordinates (km)		Relative Location (km) To Proposed Site		Distance From Proposed Site (km)	Direction From Proposed Site (degree)	Maximum NO2 * Emissions (TPY)
	East	North	X	Y			
Gardinier	415.3	3063.3	10.5	5.9	12.0	61	176
Agrico Chemical	407.5	3071.5	2.7	14.1	14.4	11	139
Mobil Oil Big Four Mine	394.7	3069.6	-10.1	12.2	15.8	320	156
U.S. Agri-Chemicals	416.0	3069.0	11.2	11.6	16.1	316	131
IMC Fort Lonesome	389.5	3067.9	-15.3	10.5	18.6	304	610
Farmland Industries	409.5	3080.1	4.7	22.7	23.2	12	226
IMC	396.7	3079.4	-8.1	22.0	23.4	340	322
Kaplan Industries	418.3	3079.3	13.5	21.9	25.7	32	100
Mobil Chemical Co./Nichols	398.4	3085.3	-6.4	27.9	28.6	347	134
W.R. Grace & Co.	409.8	3086.7	5.0	29.3	29.7	10	528
FPL Manatee	367.2	3054.1	-37.6	-3.3	37.7	265	22,734
Consolidated Minerals	393.8	3096.3	-11.0	38.9	40.4	344	534
Sherex Polymers	410.7	3098.9	5.9	41.5	41.9	352	617
Juice Bowl Products	409.4	3099.9	4.6	42.5	42.7	354	109
Owens-Illinois	406.0	3102.3	1.2	44.9	44.9	358	391
Teco Big Bend	361.9	3075.0	-42.9	17.6	46.4	292	82,624
Citrus World	441.0	3087.3	36.2	29.9	47.0	50	1,382
Gardinier	362.9	3082.2	-41.9	24.8	48.7	301	466
Lakeland City Power	409.2	3106.2	4.4	48.8	49.0	5	5,028
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* Maximum facility emissions from APIS, or other available information on facility.

Table 6-4. PM Sources (>100 TPY) Within 50 km of Proposed Hardee Power Station

Facility	UTM Coordinates (km) East	UTM Coordinates (km) North	Relative Location (km) To Proposed Site X	Relative Location (km) To Proposed Site Y	Distance From Proposed Site (km)	Direction From Proposed Site (degree)	Maximum PM * Emissions (TPY)
Gardinier	415.3	3063.3	10.5	5.9	12.0	61	132
Imperial Phosphates	404.8	3069.5	0.0	12.1	12.1	0	162
Agrico Chemical	407.5	3071.5	2.7	14.1	14.4	11	1,705
Mobil Oil Big Four Mine	394.7	3069.6	-10.1	12.2	15.8	320	263
U.S. Agri-Chemicals	416.0	3069.0	11.2	11.6	16.1	316	871
Biochemical Energy, LTD	418.3	3048.0	13.5	-9.4	16.5	125	281
IMC Fort Lonesome	389.5	3067.9	-15.3	10.5	18.6	304	679
IMC	398.2	3075.7	-6.6	18.3	19.5	340	168
Agrico Chemical	403.7	3079.0	-1.1	21.6	21.6	357	631
C&M Products	405.5	3079.1	0.7	21.7	21.7	358	162
Mobil-Electrophos Division	405.6	3080.0	0.8	22.6	22.6	358	555
Farmland Industries	409.5	3080.1	4.7	22.7	23.2	12	977
IMC	396.7	3079.4	-8.1	22.0	23.4	340	162
IMC	414.7	3080.3	9.9	22.9	24.9	337	973
C.F. Industries	408.4	3082.4	3.6	25.0	25.3	352	788
IMC/ Uranium Recovery	408.4	3082.8	3.6	25.4	25.7	8	831
American Orange Corp.	429.8	3047.3	25.0	-10.1	27.0	112	180
Conserv Chemical	398.7	3084.2	-6.1	26.8	27.5	13	1,620
Royster	406.8	3085.1	2.0	27.7	27.8	4	210
Mobil Chemical Co./Nichols	398.4	3085.3	-6.4	27.9	28.6	347	433
W.R. Grace & Co.	409.8	3086.7	5.0	29.3	29.7	10	636
Ridge Pallets	418.6	3084.1	13.8	26.7	30.1	27	180
U.S. Agri-Chemicals	413.2	3086.3	8.4	28.9	30.1	16	182
Allsun Products	413.5	3093.8	8.7	36.4	37.4	13	317
FPL Manatee	367.2	3054.1	-37.6	-3.3	37.7	265	7,578
Consolidated Minerals	393.8	3096.3	-11.0	38.9	40.4	344	740
Pavers, Inc.	414.0	3098.2	9.2	40.8	41.8	347	114
Rinker Cencon Corp.	412.4	3099.0	7.6	41.6	42.3	350	159
Quikrete	412.8	3099.0	8.0	41.6	42.4	349	253
Landia Chemical	403.7	3101.8	-1.1	44.4	44.4	1	2,313
Kraft Citrus	399.0	3101.8	-5.8	44.4	44.8	353	108
Owens-Illinois	406.0	3102.3	1.2	44.9	44.9	358	102
Jahna Concrete, Inc.	450.0	3052.2	45.2	-5.2	45.5	97	139
Teco Big Bend	361.9	3075.0	-42.9	17.6	46.4	292	7,699
Agrico Chemical Co.	362.1	3076.1	-42.7	18.7	46.6	66	184
Macasphalt	451.1	3050.0	46.3	-7.4	46.9	99	165
Citrus World	441.0	3087.3	36.2	29.9	47.0	50	166
FPL Avon Park	451.4	3050.5	46.6	-6.9	47.1	98	212
Gardinier	362.9	3082.2	-41.9	24.8	48.7	301	863
Lakeland City Power	409.2	3106.2	4.4	48.8	49.0	5	14,705
Coca Cola Citrus	421.6	3103.7	16.8	46.3	49.3	20	334
Adams Packing Association	421.7	3104.2	16.9	46.8	49.8	20	129

* Maximum facility emissions from APIS, or other available information on facility.

Table 6-5. Summary of SO2 Emission Sources Considered in the Modeling Analysis for the Hardee Power Station

Facility	Location from Proposed Facility Distance (km)	Location from Proposed Facility Direction (degrees)	Maximum SO2 Emissions (TPY)	Emission Threshold, Q (TPY)	Included in Modeling	Modeled Sources in Analyses: Screen.	Modeled Sources in Analyses: Refined
Gardinier	12.0	61	1,173	241	YES	YES	YES
Imperial Phosphate	12.1	0	275	242	YES	NO	YES
Agrico Chemical Co. (S. Pierce)	14.4	11	4,557	287	YES	YES	YES
Mobil Oil Big Four Mine	15.8	320	569	317	YES	NO	YES
U.S. Agri-Chemicals	16.1	44	2,933	322	YES	YES	YES
Wachula City Power Plant	17.1	127	180	342	NO	--	--
IMC Fort Lonesome	18.6	304	1,714	371	YES	YES	YES
Agrico Chemical Co. (Pierce)	21.6	357	417	433	NO	--	--
Mobil-Electrophosphate Division	22.0	2	1,428	440	YES	NO	YES
Farmland Industries	23.2	12	3,692	464	YES	YES	YES
IMC	23.4	340	10,251	469	YES	YES	YES
IMC/Noralyn Mine Road	24.9	23	505	499	YES	NO	YES
C.F. Industries	25.3	8	8,443	505	YES	YES	YES
Kaplan Industries	25.7	32	385	515	NO	--	--
American Orangr Corp.	27.0	112	198	539	NO	--	--
Conserv. Chemicals	27.5	347	1,597	550	YES	NO	YES
Royster Co.	27.8	4	1,283	555	YES	NO	YES
Mobil Chemical Co./Nichols	28.6	347	1,516	572	YES	NO	YES
IMC/Prairie	29.7	356	137	593	NO	--	--
W.R. Grace & Co.	29.7	10	8,186	594	YES	YES	YES
U.S. Agri-Chemicals	30.1	16	1,575	602	YES	NO	YES
FPL Manatee	37.6	265	85,305	753	YES	YES	YES
Tricil Recovery Services	38.9	27	240	777	NO	--	--
Consolidated Minerals	40.4	344	3,302	809	YES	YES	YES
Teco Big Bend	46.4	292	371,733	927	YES	YES	YES
Citrus World	47.0	50	597	939	NO	--	--
Columbus Company	47.5	295	167	950	NO	--	--
Gardinier	48.4	301	5,181	967	YES	YES	YES
Lakeland City Power	49.0	5	4,014	980	YES	YES	YES
Lakeland City Power	49.0	5	30,176	980	YES	YES	YES
Adams Packing	49.8	20	172	995	NO	--	--

			551,901				

Table 6-6. Summary of NO2 Emission Sources Considered in the Modeling Analysis for the Hardee Power Station

Facility	Location From Proposed Facility Distance (km)	Direction (degrees)	Maximum NO2 Emissions (TPY)	Emission Threshold, Q (TPY)	Included in Modeling	Modeled Sources in Analyses: Screen.	Refined
Gardinier	12.0	61	176	241	NO	--	--
Agrico Chemical	14.4	11	139	287	NO	--	--
Mobil Oil Big Four Mine	15.8	320	156	317	NO	--	--
U.S. Agri-Chemicals	16.1	316	131	322	NO	--	--
IMC Fort Lonesome	18.6	304	610	371	YES	NO	YES
Farmland Industries	23.2	12	226	464	NO	--	--
IMC	23.4	340	322	469	NO	--	--
Kaplan Industries	25.7	32	100	515	NO	--	--
Mobil Chemical Co./Nichols	28.6	347	134	572	NO	--	--
W.R. Grace & Co.	29.7	10	528	594	NO	--	--
FPL Manatee	37.6	265	22,734	753	YES	YES	YES
Consolidated Minerals	40.4	344	534	809	NO	--	--
Sherex Polymers	41.9	352	617	838	NO	--	--
Juice Bowl Products	42.7	354	109	855	NO	--	--
Owens-Illinois	44.9	358	391	898	NO	--	--
Teco Big Bend	46.4	292	82,624	927	YES	YES	YES
Citrus World	47.0	50	1,382	939	YES	NO	YES
Gardinier	48.4	301	466	967	NO	--	--
Lakeland City Power	49.0	5	5,028	980	YES	YES	YES
		Total	116,407				

Table 6-7. Summary of PM Emission Sources Considered in the Modeling Analysis for the Hardee Power Station

Facility	Location from Proposed Facility Distance (km)	Location from Proposed Facility Direction (degrees)	Maximum PM Emissions (TPY)	Emission Threshold, Q (TPY)	Included in Modeling	Modeled Sources in Analyses: Screen.	Modeled Sources in Analyses: Refined
Gardinier	12.0	61	132	241	NO	--	--
Imperial Phosphates	12.1	0	162	242	NO	--	--
Agrico Chemical	14.4	11	1,705	287	YES	YES	YES
Mobil Oil Big Four Mine	15.8	320	263	317	NO	--	--
U.S. Agri-Chemicals	16.1	316	871	322	YES	NO	YES
Biochemical Energy, LTD	16.5	125	281	329	NO	--	--
IMC Fort Lonesome	18.6	304	679	371	YES	NO	YES
IMC	19.5	340	168	389	NO	--	--
Agrico Chemical	21.6	357	631	433	YES	NO	YES
C&M Products	21.7	358	162	434	NO	--	--
Mobil-Electrophos Division	22.0	358	555	440	YES	NO	YES
Farmland Industries	23.2	12	977	464	YES	NO	YES
IMC	23.4	340	162	469	NO	--	--
IMC	24.9	337	973	499	YES	NO	YES
C.F. Industries	25.3	352	788	505	YES	NO	YES
IMC/ Uranium Recovery	25.7	8	831	513	YES	NO	YES
American Orange Corp.	27.0	112	180	539	NO	--	--
Conserv Chemical	27.5	13	1,620	550	YES	NO	YES
Royster	27.8	4	210	555	NO	--	--
Mobil Chemical Co./Nichols	28.6	347	433	572	NO	--	--
W.R. Grace & Co.	29.7	10	636	594	YES	NO	YES
Ridge Pallets	30.1	27	180	601	NO	--	--
U.S. Agri-Chemicals	30.1	16	182	602	NO	--	--
Allsun Products	37.4	13	317	749	NO	--	--
FPL Manatee	37.6	265	7,578	753	YES	YES	YES
Consolidated Minerals	40.4	344	740	809	NO	--	--
Pavers, Inc.	41.8	347	114	836	NO	--	--
Rinker Cencon Corp.	42.3	350	159	846	NO	--	--
Quikrete	42.4	349	253	847	NO	--	--
Landia Chemical	44.4	1	2,313	888	YES	NO	YES
Kraft Citrus	44.8	353	108	896	NO	--	--
Owens-Illinois	44.9	358	102	898	NO	--	--
Jahna Concrete, Inc.	45.5	97	139	910	NO	--	--
Teco Big Bend	46.4	292	7,699	927	YES	YES	YES
Agrico Chemical Co.	46.6	66	184	932	NO	--	--
Macasphalt	46.9	99	165	938	NO	--	--
Citrus World	47.0	50	166	939	NO	--	--
FPL Avon Park	47.1	98	212	942	NO	--	--
Gardinier	48.4	301	863	967	NO	--	--
Lakeland City Power	49.0	5	14,705	980	YES	YES	YES
Coca Cola Citrus	49.3	20	334	985	NO	--	--
Adams Packing Association	49.8	20	129	995	NO	--	--
		Total	49,061				

criteria was used to determine the sources to be modeled in the screening analysis:

Distance (km)	Emission Threshold (TPY)
0 - 15	500
15 - 20	1000
20 - 25	1500
25 - 30	2000
30 - 50	3000

Facilities considered in the screening and refined analyses are presented in Tables 6-5 through 6-7. Summaries of the amount of modeled emissions in the screening phase compared to the refined phase by distance categories from the proposed facility are given in Tables 6-8 through 6-10. For the SO_2 modeling analysis, approximately 98% of the SO_2 emissions in the refined phase were modeled in the screening phase. As indicated, most of the emissions occur beyond 30 km from the proposed facility.

For the NO_2 modeling analysis, approximately 98% of the NO_2 emissions in the refined analysis were modeled in the screening phase. Similar to the SO_2 emission sources, most of the NO_2 emissions occur beyond 30 km from the proposed facility.

For the PM modeling analysis, approximately 75% of the PM emissions were modeled in the screening phase. As indicated in Tables 6-7 and 6-10, there were no emission sources within 10 km of the proposed facility (the significant impact distance) with most emissions occurring beyond 30 km from the proposed facility.

6.5 RECEPTOR LOCATIONS

As discussed in Section 6.1, the general modeling approach considered screening and refined phases to address compliance with maximum allowable PSD Class II increments and AAQS. In the ISCST modeling, concentrations were predicted for the screening phase using several receptor grids. The

Table 6-8. Summary of Modeled SO2 Emissions Used for Screening and Refined Analyses for the Hardee Power Station

Distance From Proposed Site (km)	Threshold Emissions (TPY)	Refined Analysis	Screening Analysis	
		Emissions (TPY)	Emissions (TPY)	Percent Modeled of Refined Analysis
0 - 15	> 500	6,005	5,730	95.4
15 - 20	> 1000	5,216	4,647	89.1
20 - 25	> 1500	15,876	13,943	87.8
25 - 30	> 2000	21,025	16,629	79.1
30 - 50	> 3000	501,286	499,711	99.7
0 - 50		549,408	540,660	98.4

Table 6-9. Summary of Modeled NO2 Emissions Used for Screening and and Refined Analyses for the Hardee Power Station

Distance From Proposed Site (km)	Threshold Emissions (TPY)	Refined Analysis	Screening Analysis	
		Emissions (TPY)	Emissions (TPY)	Percent Modeled of Refined Analysis
0 - 15	> 500	0	0	--
15 - 20	> 1000	610	0	0.0
20 - 25	> 1500	0	0	--
25 - 30	> 2000	0	0	--
30 - 50	> 3000	111,768	110,386	98.8
0 - 50		112,378	110,386	98.2

Table 6-10. Summary of Modeled PM Emissions Used for Screening and Refined Analyses for the Hardee Power Station

Distance From Proposed Site (km)	Threshold Emissions (TPY)	Refined Analysis	Screening Analysis	
		Emissions (TPY)	Emissions (TPY)	Percent Modeled of Refined Analysis
0 - 15	> 500	1,705	1,705	100.0
15 - 20	> 1000	1,550	0	0.0
20 - 25	> 1500	3,136	0	0.0
25 - 30	> 2000	3,875	0	0.0
30 - 50	> 3000	32,295	29,982	92.8
0 - 50		42,561	31,687	74.5

locations of the receptors were based on identifying the areas in which maximum concentrations would be expected due to the proposed unit.

A description of the receptor locations for determining compliance with PSD Class II increments and AAQS is as follows:

1. 344 receptors located in a radial grid centered on the proposed facility. These receptors were classified into two main groups: (1) plant property receptors and (2) near-field receptors.

2. The grid for the plant property receptors consisted of 36 receptors, presented in Table 6-11.

3. The grid for the near-field receptors consisted of 308 receptors located at distances of 600, 900, 1,250, 1,750, 2,250, 2,750, 3,500, 4,500, and 6,000 m along 36 radials with each radial spaced at 10 degree increments. For directions of 10 through 160 degrees, receptors at a downwind distance of 600 m from the proposed facility were not included in the analysis because these receptors are on plant property.

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 m between the distances considered in the screening phase along 9 radials, at 2 degree increments, centered on the radial which the maximum concentration was produced. For example, if the maximum concentration was produced along the 90 degree radial at a distance of 1.75 km, the refined receptor grid would consist of receptors at the following locations:

Table 6-11. Plant Property Receptors Used in the Screening Analysis for the Hardee Power Station

Direction (degrees)	Distance (km)	Direction (degrees)	Distance (km)
10	1.050	190	0.450
20	1.100	200	0.420
30	1.160	210	0.390
40	0.960	220	0.380
50	0.820	230	0.360
60	0.760	240	0.420
70	0.710	250	0.490
80	0.830	260	0.410
90	1.060	270	0.360
100	0.700	280	0.330
110	0.700	290	0.320
120	0.740	300	0.300
130	0.820	310	0.300
140	0.890	320	0.300
150	0.790	330	0.320
160	0.760	340	0.350
170	0.540	350	0.400
180	0.500	360	0.450

Directions (degrees)	Distance (km)
82, 84, 86, 88, 90, 92, 94, 96, 98	1.35, 1.45, 1.55, 1.65, 1.75, 1.85, 1.95, 2.05, and 2.15 per direction

To ensure that a valid highest, second-highest concentration was calculated, concentrations were predicted for the refined grid for the periods that produced both the highest and second-highest concentration from the screening receptor grid.

Refined modeling analysis was performed for the annual average period but used a different approach than that used for short-term average periods. Because the spatial distributions of annual average concentrations are not expected to vary significantly from those produced from the screening analysis, concentrations were calculated at the receptor which produced the highest annual concentration in the screening analysis. For this analysis, concentrations were calculated for the entire year using the refined emission inventory.

6.6 BACKGROUND CONCENTRATIONS

Background concentrations are air quality concentrations due to air pollutant sources not explicitly accounted for in the air modeling analysis. Because the site is not located near any major sources of SO_2, PM, and NO_x emissions, background concentrations are expected to be low. As a result, existing monitoring data were used to estimate background concentrations. A summary of the maximum concentrations measured at the closest monitors to the proposed facility is presented in Table 6-12. The ambient data are collected in areas that are more industrialized and have higher emission densities than the proposed site. Therefore the estimated background concentrations are considered to be conservative (i.e., higher concentrations than actually exist at the proposed plant site).

For SO_2 concentrations, data collected at the monitoring stations in Nichols and Lakeland were reviewed and used in estimating background concentrations. The nearest station to the proposed site is located in Nichols,

Table 6-12. Summary of maximum SO_2, TSP, and NO_2 Concentrations Measured at the Closest Monitoring State on to the Proposed Hardee Power Station

Pollutant	Location	Site Number	UTM Coordinates (km)* East	UTM Coordinates (km)* North	Year	Observations+ Number	Observations+ %	Concentration (ug/m3) 3-Hour 1st	3-Hour 2nd	24-Hour 1st	24-Hour 2nd	Annual
SO_2	Lakeland	2160-001-F01	407.5	3107.5	1987	8444	96.4	200	162	86	55	10
			(3°, 50 km)		1986	6520	74.4	267	178	81	71	13
	Nichols	3680-010-F02	399.5	3081.3	1987	8571	97.8	697	267	115	51	11
			(348°, 24.5 km)		1986	4994	57.0	203	162	38	35	7
TSP	Lakeland	2160-001-F01	407.5	3107.5	1987	58	95.1	-	-	87	86	50
			(3°, 50 km)		1986	58	95.1	-	-	109	87	47
	Nichols	3680-010-F02	399.5	3081.3	1987	58	95.1	-	-	73	73	38
			(348°, 24.5 km)		1986	58	95.1	-	-	119	81	38
	Bartow	0180-010-F01	418.4	3084.15	1987	42	68.9	-	-	74	71	40
			(27°, 29.9 km)		1986	57	93.4	-	-	70	70	37
	Mulberry	2860-003-F02	405.0	3085.5	1987	42	68.9	-	-	75	75	43
			(360°, 28 km)		1986	54	88.5	-	-	74	74	38
	Bradley	3680-011-F02	403.1	3074.8	1987	61	100.0	-	-	110	91	45
			(354°, 17.5 km)		1986	60	98.4	-	-	94	80	41
NO_2	Ybor City	4360-052-601	358.4	3093.5	1987	6005	68.6	-	-	-	-	45
			(308°, 59.8 km)		1986	7808	89.1	-	-	-	-	39

* Direction and distance from the site listed in parentheses.
\+ For TSP, based on observations every 6 days (61 per year).
Source: FDER, 1987/88

approximately 24.5 km to the north-northwest. During 1987, the second highest 3- and 24-hour and annual average concentrations were 267, 51, and 11 ug/m^3, respectively. These concentrations were assumed to represent background concentrations.

TSP concentration data collected at the monitoring station in Bradley were used in estimating background PM_{10} concentrations. These values were the second highest 24-hour and annual average concentrations of 91 and 45 ug/m^3, respectively. The data from this station were selected because this is the closest station to the project site with TSP concentrations. It should be noted that the AAQS for particulate matter is based on PM with a nominal diameter of 10 u or less. TSP concentrations include particles with diameters up to approximately (PM10) 30 u. Therefore, the use of TSP concentrations to estimate PM10 background concentrations will provide an additional conservative factor in determining compliance with AAQS.

There are no stations within 50 km of the proposed site location that measure NO_2 concentrations. The nearest station to the proposed site is located in Ybor City, Hillsborough County, approximately 60 km to the west-northwest. This station is in a highly urbanized area and has a significant impact from vehicular traffic. During 1987, this station measured an annual average concentration of 45 ug/m^3, based on 69% data capture. This concentration was used to represent a conservative estimate of the background concentration.

6.7 BUILDING DOWNWASH EFFECTS

Based on the building dimensions associated with buildings or structures at the proposed facility, the stack for the proposed unit will be less than GEP. Therefore, the potential for building downwash to occur must be considered in the modeling analysis.

The procedures used for addressing the effects of building downwash are those recommended in the ISC Dispersion Model User's Guide. The building height, length, and width are input to the model which are used to modify the dispersion parameters. For short stacks (i.e., physical stack height is less than h_b + 0.5 L_B, where h_b is the building height and L_b is the lessor of the building height or projected width), the Schulman and Scire method is used. If this method is used, then direction-specific building dimensions are input for h_b and L_B for the 36 directions, with each direction representing a 10 degree sector. The features of the Schulman and Scire method are: 1) reduced plume rise due to initial plume dilution, 2) enhanced plume spread as a linear function of the effective plume height, and 3) specification of building dimensions as a function of wind direction.

For cases where the physical stack is greater than h_b + 0.5 L_B but less than GEP, the Huber-Snyder method is used. For this method, the ISCST model calculates the area of the building using the length and width, assumes the area is representative of a circle, and then calculates a building width by determining the diameter of the circle. If a specific width is to be modeled, then the value input to the model must be adjusted according to the following formula:

$$M_w = \sqrt{\left(\frac{H_w}{2}\right)^2}$$

$$M_w = 0.8886\ H_w$$

where M_w is input to the model to produce a building width of H_w used in the dispersion calculation.
H_w is the actual building width for which dispersion calculations are performed.

The building dimensions considered for the proposed facility are presented in Table 6-13. In these analyses, building downwash conditions were assumed to occur for all directions around each stack although these conditions may not occur for certain directions. Based on sensitivity analyses performed for the proposed facility, higher concentrations were produced with the

Table 6-13. Structure Dimensions and GEP Stack Height Calculations for the Hardee Power Station

Structure	Building Dimensions (ft)				GEP Stack Height
	Height	Length	Width	Maximum Projected Width	
HRSG*	45	50	25	56	113
Combustion Turbine Enclosure**	40	1175	75	1178	100

Note: These structure dimensions produced the worst case impacts for a HRSG stack height of 75 feet.

* Used in modeling analyses.

** Based on a single structure that encloses all the combustion turbines associated with a 660 MW plant.

building dimension using a height of 45 ft which also produced the highest GEP height. Therefore, the building dimensions associated with this height were used in performing subsequent model calculations.

7.0 AIR QUALITY MODELING RESULTS

7.1 PROPOSED FACILITY ONLY

For the screening analysis, a summary of the maximum SO_2, NO_2, PM, CO, and Be concentrations due to the proposed facility is presented in Table 7-1. Model results were calculated for a range of operating conditions for which maximum impacts could occur (see Section 2.0 for the operating data and rational for modeling these conditions). These operating conditions, which were based on either maximum emissions or minimum flow rate for the units, were as follows:

1. Case 1: Maximum emissions at 32°F;
2. Case 2: Maximum emissions at 95°F;
3. Case 3: Minimum flow rate at 32°F; and
4. Case 4: Minimum flow rate at 95°F.

As indicated in Table 7-1, the maximum concentrations are predicted for the operating conditions with minimum flow rates (Cases 3 and 4). It should be noted that the modeled SO_2 emissions were specific for each case because the maximum predicted SO_2 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 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). See Section 2.0 for a more detailed discussion about the emission data and associated operating parameters used in the modeling.

The maximum predicted 3-, 24-hour and annual SO_2 concentrations are 424, 62.5 and 6.7 ug/m^3, respectively. The maximum 24-hour concentration is above the <u>de minimis</u> monitoring level and, therefore, preconstruction monitoring data are required to be submitted by the Applicant as part of the permit application. As indicated in Section 5.0, existing monitoring data collected by the FDER are being used in this application to satisfy preconstruction monitoring requirements and to establish background concentrations.

Table 7-1. Maximum Concentrations Predicted for the Combined Cycle Plant (660 MW) for 4 Operating Designs

Pollutant	Averaging Period	Maximum Concentrations (ug/m3)				Air Quality Requirements (ug/m3)	
		Maximum Emissions		Minimum Flow Rate		Deminimis Levels	PSD Class II Increment
		32 oF	95 oF	32 oF	95 oF		
		Case 1	Case 2	Case 3	Case 4		
SO2	3-hour	196	281	359	424	NA	512
	24-hour	54.7	53.8	62.5	60.0	13	91
	Annual	5.8	5.7	6.7	6.5	NA	20
PM(TSP)	24-hour	5.1	5.9	6.4	7.5	10	37
	Annual	0.54	0.63	0.68	0.82	NA	19
PM(PM10)	24-hour	5.1	5.9	6.4	7.5	10	NA
	Annual	0.54	0.63	0.68	0.82	NA	NA
NO2	Annual	3.0	3.5	3.8	4.6	14	25
CO	1-hour	99.0	112.0	130.3	178.5	NA	NA
	8-hour	21.4	24.2	26.1	38.0	575	NA
Be	24-hour	0.0002	0.0003	0.0003	0.0004	0.001	NA
Hg	24-hour	0.0011	0.0012	0.0013	0.0016	0.25	NA

NA = Not applicable

* Modeled as 3 stacks, each separated by 100 m.

The maximum predicted 24-hour and annual average PM concentrations are 7.5 and 0.82 ug/m^3, respectively. Because the maximum 24-hour concentration is below the de minimis monitoring level, preconstruction is not required for the permit application.

The maximum predicted annual NO_2 concentration is 4.6 ug/m^3, which is below the de minimis monitoring level. Similar to the PM concentrations, preconstruction monitoring requirements is not required for the permit application.

The maximum predicted 1- and 8-hour average CO concentrations are 17.9 and 38.0 ug/^{3}, respectively, which are less than the significance levels. The maximum 8-hour concentration is also less than the de minimis monitoring levels and, therefore, preconstruction monitoring is not required. Because the maximum predicted impacts due to the proposed facility are less than the CO significance levels, additional modeling is not required for this pollutant.

The maximum predicted 24-hour average Be and Hg concentrations are 0.0004 and 0.0016 ug/m^3, respectively, which are less than the de minimis monitoring levels. Therefore, preconstruction monitoring is not required for these pollutants.

7.2 PSD CLASS II INCREMENT ANALYSIS

Summaries of the maximum SO_2, PM, and NO_2 concentrations predicted in the screening analysis for comparison to the PSD Class II increments are presented in Tables 7-2 through 7-4, respectively. These results show that maximum concentrations due to all PSD sources are less than the maximum allowable PSD Class II increments for all averaging periods and pollutants.

The refined analysis was based on modeling the meteorological periods during which the overall highest, second-highest and associated highest 3- and 24-hour SO_2 and 24-hour PM concentrations were predicted in the screening analysis. The refined analysis for the annual average concentrations was based on modeling the receptor and year which produced

Table 7-2. Maximum Predicted SO_2 Concentrations in the Screening Analysis for Comparison to PSD Class II Increments

Averaging Period	Maximum Concentration (ug/m^3)	Receptor Location: Direction (°)	Receptor Location: Distance (km)	Period: Julian Day	Period: Hour Ending	Period: Year
3-Hour*	194^{+}	110	2.25	214	12	1982
	195^{+}	310	1.75	211	12	1983
	198^{+}	130	2.75	59	6	1984
	424^{**}	360	0.45	243	12	1985
	203^{+}	90	0.90	194	15	1986
24-Hour*	62.6^{+}	240	2.25	241	24	1982
	58.2^{+}	240	3.50	289	24	1883
	58.5^{**}	120	0.74	59	24	1984
	61.4^{+}	90	2.75	118	24	1985
	60.5^{+}	90	2.25	201	24	1986
Annual	8.0^{++}	240	3.50	-	-	1982
	6.5^{**}	240	3.50	-	-	1983
	8.1^{**}	240	3.50	-	-	1984
	7.4^{++}	250	3.50	-	-	1985
	8.0^{**}	90	1.75	-	-	1986

* Highest, second-highest concentrations predicted for this averaging period.
\+ Based on Operating Case 3.
** Based on Operating Case 4.
++ Based on Operating Cases 3 and 4.

Table 7-3. Maximum Predicted PM Concentrations in the Screening Analysis for Comparison to PSD Class II Increments

Averaging Period	Maximum Concentration (ug/m^3)	Receptor Location: Direction (°)	Receptor Location: Distance (km)	Period: Julian Day	Period: Hour Ending	Period: Year
24-Hour*	7.5	240	1.75	123	24	1982
	6.9	240	3.50	289	24	1883
	6.0	240	4.50	313	24	1984
	7.2	90	2.25	118	24	1985
	6.5	90	1.75	201	24	1986
Annual	0.8	240	3.50	-	-	1982
	0.6	240	3.50	-	-	1983
	0.8	240	3.50	-	-	1984
	0.7	250	3.50, 4.50	-	-	1985
	0.8	90	1.75	-	-	1986

* Highest, second-highest concentrations predicted for this averaging period.

Table 7-4. Maximum Predicted NO_2 Concentrations in the Screening Analysis for Comparison to PSD Class II Increments

Averaging Period	Maximum Concentration (ug/m^3)	Receptor Location		Period		
		Direction (°)	Distance (km)	Julian Day	Hour Ending	Year
Annual	4.6	240	3.50	-	-	1982
	3.3	240	3.50	-	-	1983
	4.4	240	3.50	-	-	1984
	4.0	240	4.50	-	-	1985
	4.5	90	1.75	-	-	1986

the highest annual concentration using the refined emission inventory. A summary of the maximum SO_2, PM, and NO_2 concentrations predicted in the refined analysis is presented in Table 7-5.

The maximum 3-hour average SO_2 PSD increment consumption from the refined analysis is predicted to be 424 ug/m^3, which is 83% of the maximum allowable PSD Class II increment of 512 ug/m^3, not to be exceeded more than once per year. The proposed facility contributed 100% to this maximum 3-hour average concentration.

The maximum 24-hour average SO_2 PSD increment consumption is predicted to be 66.0 ug/m^3, which is 73% of the maximum allowable PSD Class II increment of 91 ug/m^3, not to be exceeded more than once per year. Approximately 99% of this concentration is due to the proposed facility.

The maximum annual average SO_2 PSD increment consumption is predicted to be 8.1 ug/m^3, which is 41% of the maximum allowable PSD Class II increment of 20 ug/m^3. Approximately 77% of this concentration is due to the proposed facility.

The maximum 24-hour average TSP PSD increment consumption is predicted to be 8.0 ug/m^3, which is 22% of the maximum allowable PSD Class II increment of 37 ug/m^3, not to be exceeded more than once per year. Approximately 99% of this concentration is due to the proposed source.

The maximum annual average TSP PSD increment consumption from the refined analysis is predicted to be 0.9 ug/m^3, which is 6% of the maximum allowable PSD Class II increment of 19 ug/m^3. Approximately 89% of this concentration is due to the proposed facility.

The maximum annual average NO_2 PSD increment consumption from the refined analysis is predicted to be 4.6 ug/m^3, which is 17% of the maximum allowable PSD Class II increment of 25 ug/m^3. This concentration is entirely due to the proposed facility.

Table 7-5. Maximum Predicted SO_2, PM, and NO_2 Concentrations in the Refined Analysis for Comparison to PSD Class II Increments

Averaging Period	Maximum Concentration (ug/m^3)	Receptor Location Direction (°)	Receptor Location Distance (km)	Period Julian Day	Period Hour Ending	Period Year
SO_2 Concentrations						
3-Hour*	424	360	0.45	243	12	1985
24-Hour*	66.0	242	2.05	241	24	1982
Annual	8.1	240	3.5	--	--	1984
PM (TSP) Concentrations						
24-Hour*	8.0	242	1.95	123	24	1982
Annual	0.9	240	3.5	--	--	1982
NO_2 Concentrations						
Annual	4.6	240	3.5	--	--	1982

* Highest, second-highest concentrations predicted for this averaging period.

7.3 AAQS ANALYSIS

A summary of the maximum 3-hour, 24-hour, and annual average total SO_2 concentrations predicted in the screening analysis is presented in Table 7-6. Summaries of the maximum 24-hour and annual total PM and annual NO_2 concentrations are given in Tables 7-7 and 7-8, respectively. The total concentrations are determined from the impacts of the modeled sources added to the background concentration determined from monitoring data. These results show that the maximum SO_2, PM, and NO_2 concentrations due to all sources are below the AAQS for all averaging periods.

Similar to the PSD Class II increment analysis, the refined analysis was based on modeling the meteorological periods during which the overall highest, second-highest and associated highest 3- and 24-hour concentrations were predicted in the screening analysis. A summary of the maximum SO_2 and PM concentrations predicted in the refined analysis is presented in Table 7-9.

The maximum 3-hour average SO_2 concentration due to all sources from the refined analysis is predicted to be 691 ug/m^3, which is 53% of the AAQS of 1300 ug/m^3, not to be exceeded more than once per year. The proposed facility contributed 61% to this maximum 3-hour average concentration.

The maximum 24-hour average SO2 concentration due to all sources is predicted to be 169 ug/m^3, which is 65% of the AAQS of 260 ug/m^3, not to be exceeded more than once per year. The proposed facility contributed 29% to this maximum 24-hour average concentration.

The maximum annual average SO_2 concentration due to all sources is predicted to be 30.3 ug/m^3, which is 51% of the AAQS of 60 ug/m^3. The proposed facility contributed 20% to the maximum concentration.

The maximum 24-hour PM concentration due to all sources is predicted to be 112 ug/m^3, which is 75% of the AAQS of 150 ug/m^3. The proposed facility did not contribute to this maximum concentration.

Table 7-6. Maximum Predicted Total SO_2 Concentrations in the Screening Analysis for Comparison to AAQS

	Concentration (ug/m^3)			Receptor Location		Period		
		Total Due To						
Averaging Period	Total	Modeled Sources	Background	Direction (°)	Distance (km)	Julian Day	Hour Ending	Year
3-hour[*]	607	340[+]	267	110	1.75	214	12	1982
	634	367[++]	267 and case 1	30	2.75	151	9	1983
	589	322[+]	267 case 1	110	1.25	226	12	1984
	691	424[**]	267	360	0.45	243	12	1985
	579	312[**]	267 and case 1	10	6.00	230	9	1986
24-hour[*]	163	112[**]	51	120	1.75	234	24	1982
	152	101[**]	51	190	2.75	299	24	1983
	149	97.9[**]	51	120	2.75	96	24	1984
	152	101[**]	51	90	2.25	153	24	1985
	146	94.9[**]	51	110	2.25	106	24	1986
Annual	27.4	16.4[**]	11	240	3.50	-	-	1982
	28.5	17.5[**]	11	270	4.50	-	-	1983
	29.4	18.4[**] 19.5	11 case 1	50	6.00	-	-	1984
	29.2	18.2[**]	11	70	2.75	-	-	1985
	29.5	18.5[**]	11	80	1.75	-	-	1986

[*] Highest, second-highest concentrations predicted for this averaging period.
[+] Based on Operating Case 3.
[**] Based on Operating Case 4.
[++] Based on Operating Cases 3 and 4.

Table 7-7. Maximum Predicted Total PM Concentrations in the Screening Analysis for Comparison to AAQS

Averaging Period	Concentration (ug/m³) Total	Total Due To: Modeled Sources	Total Due To: Background	Receptor Location: Direction (°)	Receptor Location: Distance (km)	Period: Julian Day	Period: Hour Ending	Period: Year
24-hour*	101	9.7	91	20	6.00	38	24	1982
	104	12.5	91	20	6.00	297	24	1983
	100	10.3	91	30	6.00	317	24	1984
	104	12.9	91	30	6.00	350	24	1985
	101	9.8	91	360	6.00	303	24	1986
Annual	46.4	1.4	45	240	2.75	-	-	1982
	46.3	1.3	45	300	6.00	-	-	1983
	46.4	1.4	45	240	3.50	-	-	1984
	46.4	1.4	45	80	2.25	-	-	1985
	46.4	1.4	45	90	1.75	-	-	1986

* Highest, second-highest concentrations predicted for this averaging period.

Table 7-8. Maximum Predicted Total NO_2 Concentrations in the Screening Analysis for Comparison to AAQS

Averaging Period	Concentration (ug/m^3) Total	Total Due To: Modeled Sources	Total Due To: Background	Receptor Location: Direction (°)	Receptor Location: Distance (km)	Period: Julian Day	Period: Hour Ending	Period: Year
Annual	50.7	5.7	45	240	3.50	-	-	1982
	49.7	4.7	45	240	3.50	-	-	1983
	50.8	5.8	45	240	4.50	-	-	1984
	50.5	5.5	45	240	4.50	-	-	1985
	50.8	5.8	45	90	1.75	-	-	1986

Table 7-9. Maximum Predicted SO_2, PM and NO_2 Concentrations in the Refined Analysis for Comparison to AAQS.

Average Period	Concentration (ug/m^3) Total	Total due to Modeled Sources	Total due to Background	Receptor Location Direction (o)	Receptor Location Distance (km)	Period Julian Day	Period Hour Ending	Period Year
SO_2 Concentrations								
3-Hour*	691	424	267	360	0.45	243	12	1985
24-Hour*	169	118	51	116	2.15	234	24	1982
Annual	30.3	19.3	11	80	1.75	---	---	1986
PM (TSP) Concentrations								
24-Hour*	112	21.2	91	28	6.2	13	24	1985
Annual	48.6	3.6	45	240	3.5	---	---	1984
NO_2 Concentration								
Annual	50.9	5.9	45	90	1.75	---	---	1986

* Highest, second-highest concentrations predicted for this averaging period.

The maximum annual average concentration due to all sources is predicted to be 48.6 ug/m^3, which is 97% of the AAQS of 50 ug/m^3. The proposed facility contributed less than 2% to the maximum concentration.

The maximum annual average NO_2 concentrations of 50.9 ug/m^3 due to all sources is below the AAQS of 100 ug/m^3. The proposed facility contributed approximately 8% to the maximum concentration.

7.4 NONATTAINMENT ANALYSIS

As discussed in Section 3.4.2, the proposed facility is located approximately 40 km from that portion of Hillsborough County designated as nonattainment for TSP concentrations. Because the proposed facility is located within the area of influence of a nonattainment area (i.e., 50 km), nonattainment review requirements may apply to the facility except if the proposed facility's impacts are less than the significant impact levels. As presented in Table 3-1, the 24-hour and annual average significant impact levels for TSP concentrations are 5 and 1 ug/m^3, respectively. Based on the modeling performed for the proposed facility, the furthest distances from the site at which the proposed facility's impacts are less than the significant impact levels for any direction are as follows:

Year	Distance (km) of Significant Impact 24-hour	Annual
1982	7.5-10	Not significant
1983	7.5-10	Not significant
1984	7.5-10	Not significant
1985	7.5-10	Not significant
1986	7.5-10	Not significant

From this analysis, the proposed plant's impact is significant out to approximately 10 km from the site, based on the 24-hour average concentration. The proposed plant's impacts are not significant on an annual average basis. Because the proposed plant's predicted impacts are not significant at the TSP nonattainment area (i.e., 40 km), nonattainment review for TSP emissions is not required for this project.

8.0 IMPACTS ON AIR QUALITY RELATED VALUES, VEGETATION, AND SOILS

8.1 IMPACTS ON VEGETATION

The response of vegetation to atmospheric pollutants is influenced by the concentration of the pollutant, duration of the exposure and the frequency of exposures. The pattern of pollutant exposure expected from the facility is that of a few episodes of relatively high ground-level concentration which occur during certain meteorological conditions interspersed with long periods of extremely low ground-level concentrations. If there are any effects of stack emissions on plants they will be from the short-term higher doses. A dose is the product of the concentration of the pollutant and the duration of the exposure. The impact of the Hardee Power Station on regional vegetation was assessed by comparing pollutant doses that are predicted from modeling with threshold doses reported from the scientific literature which could adversely affect plant species typical of those present in the region.

SULFUR DIOXIDE

The maximum total 3-hour average SO_2 concentration predicted in the Hardee Power Station region is 691 ug/m^3. This concentration is predicted to occur about 0.5 km (0.24 mile) north of the stacks and represents the concentration that would occur during the worst-case meteorological conditions of the past five years (see Section 7.0). The maximum 3-hour average ground-level concentration predicted for the other four years ranged from 579 to 634 ug/m^3. These concentrations would occur between 1 (0.6 mile) and 6 km (3.7 miles) from the stacks with directions ranging from north to east-southeast. Concentrations decrease with distance beyond the location of the maximum concentration.

The maximum total predicted 24-hour average SO_2 concentration is 169 ug/m^3 and is located approximately 2 km (1.24 miles) east-southeast of the stacks. The maximum total predicated annual SO_2 concentration is 30.3 ug/m^3. This concentration is predicted to occur 1.75 km (1.1 miles) to the east of the stacks.

These concentrations and averaging times can be compared with SO_2 doses known to adversely affect plant species that are presented in Table 8-1. The expected doses from operation of the Hardee Power Station combined with background sources are much lower than doses known to cause a detrimental effect on vegetation.

NITROGEN OXIDES

The maximum predicted 3-hour, 24-hour and annual average NO_2 concentrations due to the Hardee Power Station are predicted to be 297, 42 and 4.6 ug/m^3, respectively. The maximum total predicted annual average concentrations due to all sources is 50.9 ug/m^3 which includes a background concentration of 45 ug/m^3 derived from monitoring data in Bartow. The NO_2 doses known to adversely affect some plant species that have been tested are shown in Table 8-1. The predicted doses of NO_2 due to the proposed facility are far lower than the doses reported to injure vegetation; therefore, the proposed facility's NO_2 emissions are not expected to have an adverse affect on vegetation.

TOTAL SUSPENDED PARTICULATES

The maximum total 24-hour and annual average concentrations are predicted to be 112 and 48.6 ug/m^3, respectively. These concentrations are predicted to occur between 1.75 to 6 km from the stacks. High deposition of particulates on plant leaves can reduce photosynthesis through shading and impede diffusion of gases. However, at least 5 g/m^2 leaf surface of particulates are required to cause these impacts (Thompson, et al., 1984). This concentration is not expected due to the maximum predicted impacts from the Hardee Power Station.

Table 8-1. SO_2 and NO_2 Doses Reported to Affect Plant Species Similar to Vegetation in the Region of the Hardee Power Plant

Pollutant	Species	Dose and Effect	Reference
SO_2	Strawberry	1,040 ug/m^3 for 6 hours per day for 3 days had no affect on growth	Rajput, et al.,1977
SO_2	Citrus	2,080 ug/m^3 for 23 days with 10 day interruption reduced leaf area	Matsushima and Brewer 1972
SO_2	Ryegrass	42 ug/m^3 for 26 weeks or 367 ug/m^3 for 131 days reduced dry weight	Bell, et al., 1979 Ayazaloo and Bell, 1981
SO_2	Tomato	1,258 ug/m^3 for 5 hours per day, for 57 days, reduced growth	Kohut, et al., 1983
SO_2	Duckweed	390 ug/m^3 for 6 weeks reduced growth	Fankhauser, et al., 1976
SO_2	Lichens (Parmotrema and Ramalina spp.)	400 ug/m^3 6 hours per week for 10 weeks reduced CO_2 uptake and biomass gain of Ramalina, not Parmotrema	Hart, et al., 1988
SO_2	Bald Cypress	1,300 and 2,600 ug/m^3 for 48 hours. Only 2600 ug/m^3 reduced leaf area.	Shanklin and Kozlowski, 1985
SO_2	Green Ash	210 ug/m^3 for 4 hours per day, 5 days per week for 6 weeks reduced growth	Chappelka, et al., 1988
NO_2	Ryegrass	39.5 ug/m^3 for 6 minutes had no affect on shoot weight	Lane and Bell, 1984
NO_2	Citrus	470 ug/m^3 for 290 days injured trees	Thompson, et al., 1970
NO_2	Sphagnum	11.7 ug/m^3 averaged over 18 months compared with control of 4.8 ug/m^3 (exceeded 15 ug/m^3 4 times) reduced growth	Press, et al., 1986

CARBON MONOXIDE

The maximum predicted 1-hour and 8-hour average CO concentrations due to the facility are 179 and 38.0 ug/m^3, respectively. Soil microorganisms can use carbon monoxide as a carbon source and are a major sink for this pollutant (Bennett and Hill, 1975). Plants are not known to be injured by CO. No adverse impacts to vegetation are expected from CO emissions from the Hardee Power Station.

BERYLLIUM

The maximum 24-hour average Be concentration due to the proposed facility is predicted to be 0.0004 ug/m^3. Levels of Be greater than 2 ug/g in nutrient solution have been found to reduce growth of experimental plants (Gough, et al., 1979). Therefore, the low levels of Be predicted from plant operation are not expected to adversely affect vegetation.

MERCURY

The maximum 24-hour average Hg concentration due to the proposed facility is predicted to be 0.0016 ug/m^3. Siegel, et al., (1984) reported that 7 days of exposure to 50 ug/m^3 Hg vapor resulted in massive leaf abscission in 15 plant species and cultivars. This dose is orders of magnitude higher than the dose expected from operation of the Hardee Power Plant. Therefore, the predicted Hg concentrations due to the proposed facility are not expected to adversely affect vegetation.

8.2 IMPACTS TO SOILS

Soils in the site region have been disrupted and altered by phosphate mining. They were originally sandy, siliceous hyperthermic Haploquods with very strongly acid subsoils. The undisturbed soils of the Payne Creek floodplain formed in unconsolidated loamy textured sediment influenced by calcareous material (Robbins, et al., 1984). They are coarse-loamy siliceous, hyperthermic Typic Ochraqualfs.

SO_2 and NO_2 that reach the soil by deposition from the air are converted by physical and biotic processes to sulfates and nitrates. (CO, particulates, and metals have no affect on soils at the levels predicted.) The effects can be beneficial to plants if either sulfates or nitrates in native soils are less than plant requirements for optimum growth. However, sulfates and nitrates can also increase acidity of unbuffered soils, causing adverse effects due to changes in nutrient availability and cycling. The predicted concentrations of SO_2 and NO_2 from stack emissions are not expected to have a significant adverse affect on soils in the vicinity because (1) the predicted concentrations of both gases are low, (2) Payne Creek floodplain and other wetland soils contain organic matter and/or calcium carbonate nodules that buffer changes in acidity, and (3) ground limestone will be applied to lands being reclaimed for pasture and citrus. Therefore, the facility is not expected to have a significant adverse impact on regional vegetation or soils.

8.3 IMPACTS DUE TO ADDITIONAL GROWTH

A limited number of additional personnel will be added to the work force due to the proposed facility. These additional personnel are expected to have an insignificant effect on the residential, commercial, and industrial growth of Hardee and Polk counties.

Fuel oil will be delivered by truck every week to the facility. Based on a truck capacity of 9,200 gallons, approximately 129 trucks per week trucks or 18 trucks per day will deliver oil to the site. These additional trucks are not expected to adversely affect existing traffic patterns or air quality in the vicinity of the plant.

Therefore, no air quality related impacts associated with residential, commercial and industrial growth are anticipated.

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11.1.5 APPLICATION TO OPERATE/CONSTRUCT AIR POLLUTION SOURCES

This application has been prepared for information purposes only as required by FDER Form 17-1.211(1). Refer to Applicant Information in the SCA.

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

This application is being completed for information purposes as required by Section 3.4.1 of DERFORM 17-1.211 (1); Power Plant Site Certification Application (SCA).

APPLICATION TO OPERATE/CONSTRUCT AIR POLLUTION SOURCES

SOURCE TYPE: Combustion Turbine [X] New[1] [ ] Existing[1]

APPLICATION TYPE: [ ] Construction [ ] Operation [ ] Modification

COMPANY NAME: Refer to Applicant Information in the SCA COUNTY: Hardee

Identify the specific emission point source(s) addressed in this application (i.e. Lime Kiln No. 4 with Venturi Scrubber; Peaking Unit No. 2, Gas Fired) By-Pass and HRSG Stack

SOURCE LOCATION: Street ______ City ______

UTM: East 404.8 km North 3057.4 km

Latitude ___° ___' ___"N Longitude ___° ___' ___"W

APPLICANT NAME AND TITLE: Refer to Applicant Information in the SCA

APPLICANT ADDRESS: Refer to Applicant Information in the SCA

SECTION I: STATEMENTS BY APPLICANT AND ENGINEER

A. APPLICANT N/A

I am the undersigned owner or authorized representative* of ______

I certify that the statements made in this application for a ______ permit are true, correct and complete to the best of my knowledge and belief. Further, I agree to maintain and operate the pollution control source and pollution control facilities in such a manner as to comply with the provision of Chapter 403, Florida Statutes, and all the rules and regulations of the department and revisions thereof. I also understand that a permit, if granted by the department, will be non-transferable and I will promptly notify the department upon sale or legal transfer of the permitted establishment.

*Attach letter of authorization

Signed: ______

______
Name and Title (Please Type)

Date: ______ Telephone No. ______

B. PROFESSIONAL ENGINEER REGISTERED IN FLORIDA (where required by Chapter 471, F.S.)

N/A

This is to certify that the engineering features of this pollution control project have been designed/examined by me and found to be in conformity with modern engineering principles applicable to the treatment and disposal of pollutants characterized in the permit application. There is reasonable assurance, in my professional judgment, that

[1] See Florida Administrative Code Rule 17-2.100(57) and (104)

the pollution control facilities, when properly maintained and operated, will discharge an effluent that complies with all applicable statutes of the State of Florida and the rules and regulations of the department. It is also agreed that the undersigned will furnish, if authorized by the owner, the applicant a set of instructions for the proper maintenance and operation of the pollution control facilities and, if applicable, pollution sources.

Signed ______________________________

____
Name (Please Type)

____
Company Name (Please Type)

____
Mailing Address (Please Type)

Florida Registration No. __________ Date: ______________ Telephone No. ______________

SECTION II: GENERAL PROJECT INFORMATION

A. Describe the nature and extent of the project. Refer to pollution control equipment, and expected improvements in source performance as a result of installation. State whether the project will result in full compliance. Attach additional sheet if necessary.

Refer to Section 2.0 of the PSD Application

B. Schedule of project covered in this application (Construction Permit Application Only)

Start of Construction Refer to Chapter 1 of the SCA. Completion of Construction ______________

C. Costs of pollution control system(s): (Note: Show breakdown of estimated costs only for individual components/units of the project serving pollution control purposes. Information on actual costs shall be furnished with the application for operation permit.)

Refer to Section 4.0 of the PSD Application: Table 4-4

D. Indicate any previous DER permits, orders and notices associated with the emission point, including permit issuance and expiration dates.

No previous permits have been issued.

E. Requested permitted equipment operating time: hrs/day 24 ; days/wk 7 ; wks/yr 52 ;
if power plant, hrs/yr 8760 ; if seasonal, describe: ______

F. If this is a new source or major modification, answer the following questions. (Yes or No)

1. Is this source in a non-attainment area for a particular pollutant? No

   a. If yes, has "offset" been applied? N/A

   b. If yes, has "Lowest Achievable Emission Rate" been applied? N/A

   c. If yes, list non-attainment pollutants. N/A

2. Does best available control technology (BACT) apply to this source? If yes, see Section VI. Yes

3. Does the State "Prevention of Significant Deterioriation" (PSD) requirement apply to this source? If yes, see Sections VI and VII. Yes

4. Do "Standards of Performance for New Stationary Sources" (NSPS) apply to this source? Yes

5. Do "National Emission Standards for Hazardous Air Pollutants" (NESHAP) apply to this source? No

H. Do "Reasonably Available Control Technology" (RACT) requirements apply to this source? No

   a. If yes, for what pollutants? N/A

   b. If yes, in addition to the information required in this form, any information requested in Rule 17-2.650 must be submitted. N/A

Attach all supportive information related to any answer of "Yes". Attach any justification for any answer of "No" that might be considered questionable.

Refer to the following sections in the PSD Application:

PSD Applicability - Subsection 3.4.1
Non-Attainment Applicability - Subsection 3.4.2
BACT Applicability - Section 4.1
NSPS Applicability - Section 4.2

SECTION III: AIR POLLUTION SOURCES & CONTROL DEVICES (Other than Incinerators)

A. Raw Materials and Chemicals Used in your Process, if applicable:

Not Applicable

Description	Contaminants		Utilization Rate - lbs/hr	Relate to Flow Diagram
	Type	% Wt		

B. Process Rate, if applicable: (See Section V, Item 1) Not Applicable

1. Total Process Input Rate (lbs/hr): ______

2. Product Weight (lbs/hr): ______

C. Airborne Contaminants Emitted: (Information in this table must be submitted for each emission point, use additional sheets as necessary)

Refer to Tables 2-2 through 2-4 of the PSD Application

Name of Contaminant	Emission[1]		Allowed[2] Emission Rate per Rule 17-2	Allowable[3] Emission lbs/hr	Potential[4] Emission		Relate to Flow Diagram
	Maximum lbs/hr	Actual T/yr			lbs/hr	T/yr	
TSP/PM10	57	250	--	--	57	250	Refer To
SO_2	734	3,217	0.5% sulfur fuel	1174	734	3,217	Figure 2-1 in PSD
NO_x	384	1,681	65 ppm corrected	> 440	384	1,681	Application
CO	128	562	--		128	562	
VOC	21	90	--		21	90	

Above information is maximum emissions for each CT.

[1]See Section V, Item 2.

[2]Reference applicable emission standards and units (e.g. Rule 17-2.600(5)(b)2. Table II, E. (1) - 0.1 pounds per million BTU heat input)

[3]Calculated from operating rate and applicable standard.

[4]Emission, if source operated without control (See Section V, Item 3).

D. Control Devices: (See Section V, Item 4)

Name and Type (Model & Serial No.)	Contaminant	Efficiency	Range of Particles Size Collected (in microns) (If applicable)	Basis for Efficiency (Section V Item 5)
Refer to Section 4.0 in the PSD Application				

E. Fuels Refer to Table 3-3 in SCA and Table 2-1 in PSD Application

Type (Be Specific)	Consumption*		Maximum Heat Input (MMBTU/hr)
	avg/hr	max./hr	
Natural Gas	--	1251.4 MCF/hr	
No. 2 Fuel Oil	--	73,437 lb/hr	1312.3

*Units: Natural Gas--MMCF/hr; Fuel Oils--gallons/hr; Coal, wood, refuse, other--lbs/hr.

Fuel Analysis: Refer to Tables 2-5 and 2-6 in the PSD Application

Percent Sulfur: ______ Percent Ash: ______

Density: ______ lbs/gal Typical Percent Nitrogen: ______

Heat Capacity: ______ BTU/lb ______ BTU/gal

Other Fuel Contaminants (which may cause air pollution): ______

F. If applicable, indicate the percent of fuel used for space heating.

Annual Average ______ Maximum ______

G. Indicate liquid or solid wastes generated and method of disposal.

Refer to Section 3.6 in the SCA

Refer to Table 2-7 in the PSD Application

H. Emission Stack Geometry and Flow Characteristics (Provide data for each stack):

Stack Height: ______________ ft. Stack Diameter: ______________ ft.

Gas Flow Rate: __________ ACFM __________ DSCFM Gas Exit Temperature: __________ °F.

Water Vapor Content: ______________ % Velocity: ______________ FPS

SECTION IV: INCINERATOR INFORMATION

Not Applicable

Type of Waste	Type O (Plastics)	Type I (Rubbish)	Type II (Refuse)	Type III (Garbage)	Type IV (Patholog-ical)	Type V (Liq.& Gas By-prod.)	Type VI (Solid By-prod.)
Actual lb/hr Inciner-ated							
Uncon-trolled (lbs/hr)							

Description of Waste ______________

Total Weight Incinerated (lbs/hr) __________ Design Capacity (lbs/hr) __________

Approximate Number of Hours of Operation per day ______ day/wk ______ wks/yr. ______

Manufacturer ______________

Date Constructed ______________ Model No. ______________

	Volume $(ft)^3$	Heat Release (BTU/hr)	Fuel		Temperature (°F)
			Type	BTU/hr	
Primary Chamber					
Secondary Chamber					

Stack Height: __________ ft. Stack Diamter: ______________ Stack Temp. __________

Gas Flow Rate: ______________ ACFM ______________ DSCFM* Velocity: ______________ FPS

*If 50 or more tons per day design capacity, submit the emissions rate in grains per standard cubic foot dry gas corrected to 50% excess air.

Type of pollution control device: [ ] Cyclone [ ] Wet Scrubber [ ] Afterburner

[ ] Other (specify) ______________

Brief description of operating characteristics of control devices: ______

______

______

______

______

Ultimate disposal of any effluent other than that emitted from the stack (scrubber water, ash, etc.):

______

______

______

______

NOTE: Items 2, 3, 4, 6, 7, 8, and 10 in Section V must be included where applicable.

SECTION V: SUPPLEMENTAL REQUIREMENTS

Please provide the following supplements where required for this application.

1. Total process input rate and product weight -- show derivation [Rule 17-2.100(127)]
   See Table 2-1 in the PSD Application
2. To a construction application, attach basis of emission estimate (e.g., design calculations, design drawings, pertinent manufacturer's test data, etc.) and attach proposed methods (e.g., FR Part 60 Methods 1, 2, 3, 4, 5) to show proof of compliance with applicable standards. To an operation application, attach test results or methods used to show proof of compliance. Information provided when applying for an operation permit from a construction permit shall be indicative of the time at which the test was made. Refer to Tables 2-2 through 2-4 in the PSD Application
3. Attach basis of potential discharge (e.g., emission factor, that is, AP42 test).
   Refer to Tables 2-2 through 2-4 in the PSD Application
4. With construction permit application, include design details for all air pollution control systems (e.g., for baghouse include cloth to air ratio; for scrubber include cross-section sketch, design pressure drop, etc.) Refer to Section 4.0 in the PSD Application
5. With construction permit application, attach derivation of control device(s) efficiency. Include test or design data. Items 2, 3 and 5 should be consistent: actual emissions = potential (1-efficiency). Refer to Section 4.0 in the PSD Application
6. An 8 1/2" x 11" flow diagram which will, without revealing trade secrets, identify the individual operations and/or processes. Indicate where raw materials enter, where solid and liquid waste exit, where gaseous emissions and/or airborne particles are evolved and where finished products are obtained. See Figure 2-1 in the PSD Application
7. An 8 1/2" x 11" plot plan showing the location of the establishment, and points of airborne emissions, in relation to the surrounding area, residences and other permanent structures and roadways (Example: Copy of relevant portion of USGS topographic map).
   See Figures 3.2-1 and 3.2-2 in the SCA
8. An 8 1/2" x 11" plot plan of facility showing the location of manufacturing processes and outlets for airborne emissions. Relate all flows to the flow diagram.
   See Figures 3.2-1 and 3.2-2 in the SCA

9. The appropriate application fee in accordance with Rule 17-4.05. The check should be made payable to the Department of Environmental Regulation.
Not Applicable

10. With an application for operation permit, attach a Certificate of Completion of Construction indicating that the source was constructed as shown in the construction permit.

SECTION VI: BEST AVAILABLE CONTROL TECHNOLOGY

A. Are standards of performance for new stationary sources pursuant to 40 C.F.R. Part 60 applicable to the source?

[X] Yes [ ] No 40 CFR Part 60 Subpart GG

Contaminant	Rate or Concentration
See Table 4-1 in PSD Application	

B. Has EPA declared the best available control technology for this class of sources (If yes, attach copy)

[X] Yes [ ] No

Contaminant	Rate or Concentration
Refer to Section 4.3 in the PSD Application	

C. What emission levels do you propose as best available control technology?

Contaminant	Rate or Concentration
Refer to Tables 2-2 and 2-5 in the PSD Application	

D. Describe the existing control and treatment technology (if any). Not Applicable

1. Control Device/System:
2. Operating Principles:
3. Efficiency:*
4. Capital Costs:

*Explain method of determining

5. Useful Life:

6. Operating Costs:

7. Energy:

8. Maintenance Cost:

9. Emissions:

Contaminant	Rate or Concentration

10. Stack Parameters

a. Height: ft.

b. Diameter: ft.

c. Flow Rate: ACFM

d. Temperature: °F.

e. Velocity: FPS

E. Describe the control and treatment technology available (As many types as applicable, use additional pages if necessary). Refer to Section 4.3 in the PSD Application

1.

a. Control Device:

b. Operating Principles:

c. Efficiency:[1]

d. Capital Cost:

e. Useful Life:

f. Operating Cost:

g. Energy:[2]

h. Maintenance Cost:

i. Availability of construction materials and process chemicals:

j. Applicability to manufacturing processes:

k. Ability to construct with control device, install in available space, and operate within proposed levels:

2.

a. Control Device:

b. Operating Principles:

c. Efficiency:[1]

d. Capital Cost:

e. Useful Life:

f. Operating Cost:

g. Energy:[2]

h. Maintenance Cost:

i. Availability of construction materials and process chemicals:

[1]Explain method of determining efficiency.
[2]Energy to be reported in units of electrical power - KWH design rate.

j. Applicability to manufacturing processes:

k. Ability to construct with control device, install in available space, and operate within proposed levels:

3.

a. Control Device:

b. Operating Principles:

c. Efficiency:[1]

d. Capital Cost:

e. Useful Life:

f. Operating Cost:

g. Energy:[2]

h. Maintenance Cost:

i. Availability of construction materials and process chemicals:

j. Applicability to manufacturing processes:

k. Ability to construct with control device, install in available space, and operate within proposed levels:

4.

a. Control Device:

b. Operating Principles:

c. Efficiency:[1]

d. Capital Costs:

e. Useful Life:

f. Operating Cost:

g. Energy:[2]

h. Maintenance Cost:

i. Availability of construction materials and process chemicals:

j. Applicability to manufacturing processes:

k. Ability to construct with control device, install in available space, and operate within proposed levels:

F. Describe the control technology selected: Refer to Section 4.3 in the PSD Application

1. Control Device:

2. Efficiency:[1]

3. Capital Cost:

4. Useful Life:

5. Operating Cost:

6. Energy:[2]

7. Maintenance Cost:

8. Manufacturer:

9. Other locations where employed on similar processes:

a. (1) Company:

(2) Mailing Address:

(3) City:

(4) State:

[1]Explain method of determining efficiency.
[2]Energy to be reported in units of electrical power - KWH design rate.

(5) Environmental Manager:

(6) Telephone No.:

(7) Emissions:[1]

Contaminant	Rate or Concentration

(8) Process Rate:[1]

b. (1) Company:

(2) Mailing Address:

(3) City: (4) State:

(5) Environmental Manager:

(6) Telephone No.:

(7) Emissions:[1]

Contaminant	Rate or Concentration

(8) Process Rate:[1]

10. Reason for selection and description of systems:

[1]Applicant must provide this information when available. Should this information not be available, applicant must state the reason(s) why.

SECTION VII - PREVENTION OF SIGNIFICANT DETERIORATION

A. Company Monitored Data Refer to Section 5.0 in the PSD Application

1. ____________ no. sites ____________ TSP ____________ ( ) SO^2* ____________ Wind spd/dir

Period of Monitoring ____/____/____ to ____/____/____
month day year month day year

Other data recorded ________________________________

Attach all data or statistical summaries to this application.

*Specify bubbler (B) or continuous (C).

2. Instrumentation, Field and Laboratory

a. Was instrumentation EPA referenced or its equivalent? [ ] Yes [ ] No

b. Was instrumentation calibrated in accordance with Department procedures?

[ ] Yes [ ] No [ ] Unknown

B. Meteorological Data Used for Air Quality Modeling Refer to Section 6.3 in the PSD Application

1. _____ Year(s) of data from ____/____/____ to ____/____/____
month day year month day year

2. Surface data obtained from (location)________________________

3. Upper air (mixing height) data obtained from (location)________________________

4. Stability wind rose (STAR) data obtained from (location)________________________

C. Computer Models Used

1. ________________________ Modified? If yes, attach description.

2. ________________________ Modified? If yes, attach description.

3. ________________________ Modified? If yes, attach description.

4. ________________________ Modified? If yes, attach description.

Attach copies of all final model runs showing input data, receptor locations, and principle output tables.

D. Applicants Maximum Allowable Emission Data Refer to Table 2-1 in PSD Application

Pollutant	Emission Rate	
TSP	________________________	grams/sec
SO2	________________________	grams/sec

E. Emission Data Used in Modeling Refer to Table 2-7 in the PSD Application

Attach list of emission sources. Emission data required is source name, description of point source (on NEDS point number), UTM coordinates, stack data, allowable emissions, and normal operating time.

F. Attach all other information supportive to the PSD review. Refer to PSD Application

G. Discuss the social and economic impact of the selected technology versus other applicable technologies (i.e., jobs, payroll, production, taxes, energy, etc.). Include assessment of the environmental impact of the sources. Refer to Section 4.0 of the PSD Application

H. Attach scientific, engineering, and technical material, reports, publications, journals, and other competent relevant information describing the theory and application of the requested best available control technology. Refer to Section 4.0 of the PSD Application