Florida Gas Transmission Company

P. O. Box 1188 Houston, Texas 77251-1188 (713) 853-6161

April 22, 1993

Mr. Clair Fancy, Chief
Bureau of Air Regulation
Florida Department of Environmental Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Dear Mr. Fancy:

Florida Gas Transmission Company, an ENRON/SONAT affiliate, is proposing to expand its existing pipeline system and has filed an application with the Federal Energy Regulatory Commission for a certificate of public convenience and necessity. This expansion will require the installation of three new compressor stations and the addition of new engines at eight existing stations. As discussed in a meeting on December 18, 1992, with you, Mr. Preston Lewis, and other members of your staff, two of the new stations and four of the existing stations requiring new engines are located in Florida. One of these is Compressor Station No. 20, located in St. Lucie County, near Ft. Pierce, Florida.

Attached for your consideration is one original and six copies of an application for a PSD permit for the addition of one new 4,000 bhp Cooper-Bessemer 10V-275 engine at Compressor Station No. 20. A check for the permit fee in the amount of $7,500.00 is also attached.

Should you have any questions concerning this application, please call Dr. V. Duane Pierce at (713) 853-3569.

Sincerely,

C. D. Schulz
Vice President Project Management Services
Florida Gas Transmission Company

CDS:DP
pierce\corres\acovfl20.ltr

Florida Gas Transmission Company

P. O. Box 1188 Houston, Texas 77251-1188 (713) 853-6161

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FINANCE &
1993 MAY -
DEPARTMENT OF
ENV. REGULATION

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Vice President Project Management Services
Florida Gas Transmission Company

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Florida Gas Transmission Company

P. O. Box 1188 Houston, Texas 77251-1188 (713) 853-6161

April 22, 1993

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Florida Department of Environmental Regulation
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RECEIVED
FINANCE & ACCOUNTING
93 MAY AM 11:43
DEPT. OF ENV. REGULATION

CHECK NO.
0622084214

FLORIDA GAS TRANSMISSION COMPANY
P.O. BOX 1188
HOUSTON, TEXAS 77251-1188

DATE OF CHECK
04-01-93

ENRON CORP

This check is VOID unless printed on BLUE background

EXACTLY $*****7,500 DOLLARS 00 CENTS

AMOUNT OF CHECK
$*****7,500.00

PAY TO THE ORDER OF
STATE OF FLORIDA DEPT OF
ENVIRONMENTAL REGULATION
TWIN TOWERS OFFICE BUILDING
TALLAHASSEE, FL
32399-2400

BY ______ AUTHORIZED REPRESENTATIVE

NORWEST BANK GRAND JUNCTION

0622084214 102100918 606 0034033

011-E1153 12/88

CHECK NO.
0622084214

FLORIDA GAS TRANSMISSION COMPANY
P.O. BOX 1188
HOUSTON, TEXAS 77251-1188

DATE OF CHECK
04-01-93

ENRON CORP

This check is VOID unless printed on BLUE background

VOID

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TALLAHASSEE, FL
32399-2400

BY ______
"AUTHORIZED REPRESENTATIVE"

NORWEST BANK GRAND JUNCTION

⑈0622084214⑈ ⑆102100918⑆ 606 0034033⑈

REMITTANCE STATEMENT
FLORIDA GAS TRANSMISSION COMPANY

CHECK NO. 0622084214

PAGE 001 OF 001

VOUCHER NO.	INVOICE DATE	INVOICE NUMBER	PURCHASE ORDER	AMOUNT GROSS	DISCOUNT	NET
9304000088	040193	CKR040193		7,500.00	0.00	7,500.00
AIR	PERMIT	APPLICATION FEE	FOR COMPR	ESSOR STATION	NO. 20	- FORT PIERCE
ST.	LUCIE	COUNTY, FLORIDA				
					TOTAL	7,500.00

Special Instructions
CALL MARCY BABB, X3295

P. O. BOX 1188, HOUSTON,TEXAS 77251-1188
DETACH STATEMENT BEFORE DEPOSITING ENDORSEMENT OF CHECK ATTACHED ACKNOWLEDGES PAYMENT IN FULL OF ALL ITEMS SHOWN ABOVE IN CASE OF ERROR OR OMISSION RETURN BOTH CHECK AND STATEMENT

Florida Gas Transmission Company

PHASE III EXPANSION PROJECT

Compressor Station No. 20
St. Lucie County, Florida

Prevention of Significant Deterioration and Permit to Construct Applications

Volume I

April 1993

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(Cont'd)

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LIST OF TABLES
(Cont'd)

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1.0 INTRODUCTION

Florida Gas Transmission Company (FGTC), a Delaware Corporation and ENRON/SONAT affiliate of Houston, Texas, is proposing to expand its existing natural gas pipeline facility in St. Lucie County, Florida (Compressor Station No. 20). This proposed modification is part of FGTC's overall Phase III expansion project, aimed at increasing the supply capacity of the FGTC's network servicing domestic, commercial, and industrial customers along the Gulf Coast. The scope of work for the Phase III project includes expansion, through the addition of state-of-the-art compressor engines, at eight existing compressor stations and the development of three new compressor stations. The new pipeline will follow much of the right-of-way of the existing system.

The basic project components include:

- mainline loops, additions, and replacements;
- lateral loops and additions;
- meter station additions, modifications, and expansions;
- regulator additions, modifications, and expansions; and
- compressor station additions and modifications.

The route of the main gas pipeline, and the approximate location of Compressor Station No. 20 along the main pipeline are shown in Figure 1-1.

Compressor Station No. 20 is located 6 miles west of the town of Ft. Pierce, in St. Lucie County, Florida. Figure 1-2 shows the site location of the existing compressor station.

The proposed expansion at this location consists of the installation of one (1) 4,000 brake horsepower (bhp), natural-gas-fired, reciprocating, internal combustion (IC), engine. The proposed engine will be used solely for the purpose of transporting natural gas by pipeline for distribution to markets in the Gulf Coast region. The proposed engine is a Cooper-Bessemer 10V-275C, equipped with lean-burn technology. Under current federal and state air quality regulations, the proposed engine will constitute a major modification of an existing major stationary source, due to the net change in NO_x emissions.

This report addresses the requirements of the Prevention of Significant Deterioration (PSD) review procedures pursuant to rules and regulations implementing the Clean Air Act (CAA) Amendments of 1977. The Florida Department of Environmental Regulations (FDER) has PSD review and

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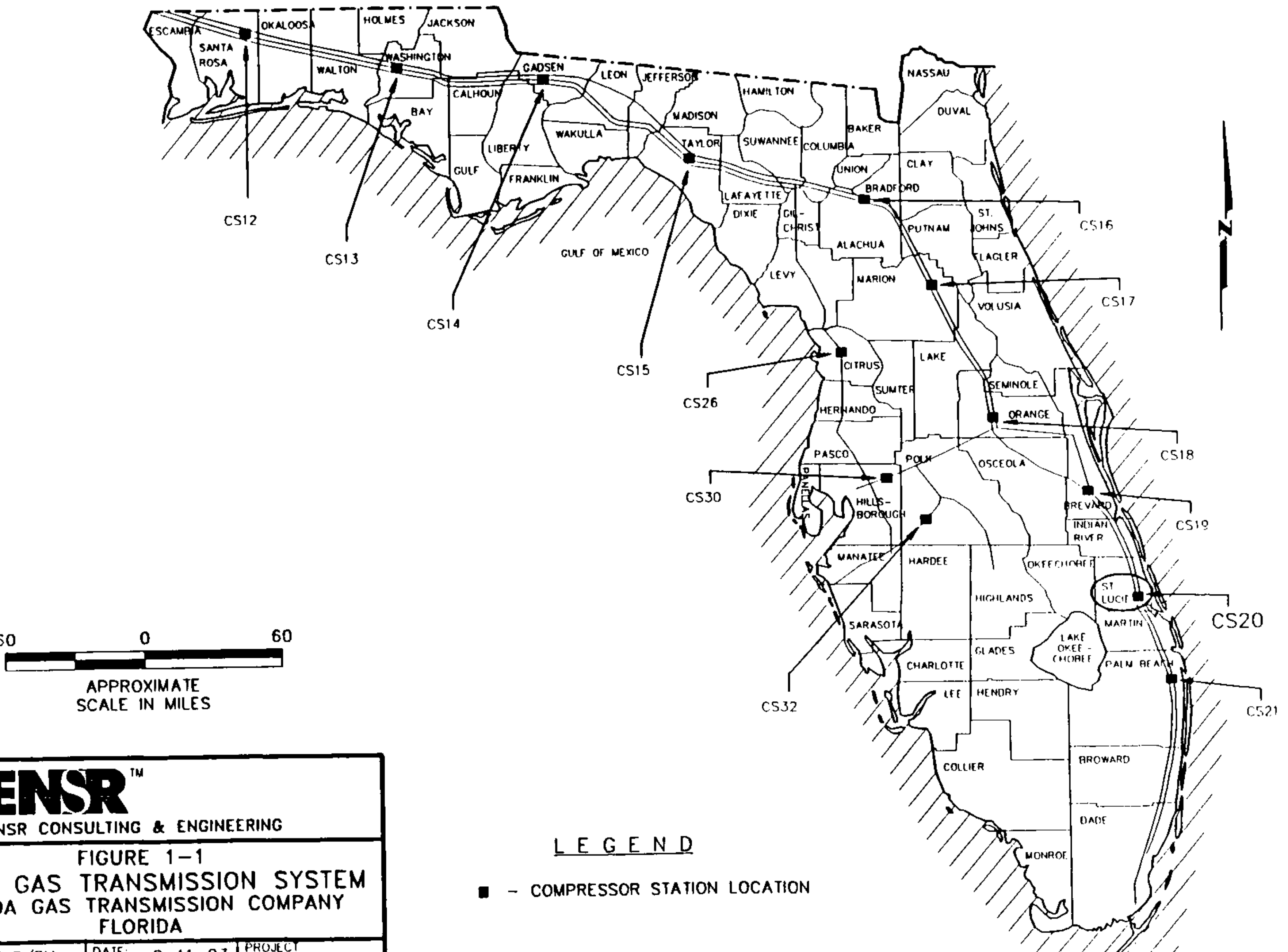

LEGEND

■ - COMPRESSOR STATION LOCATION

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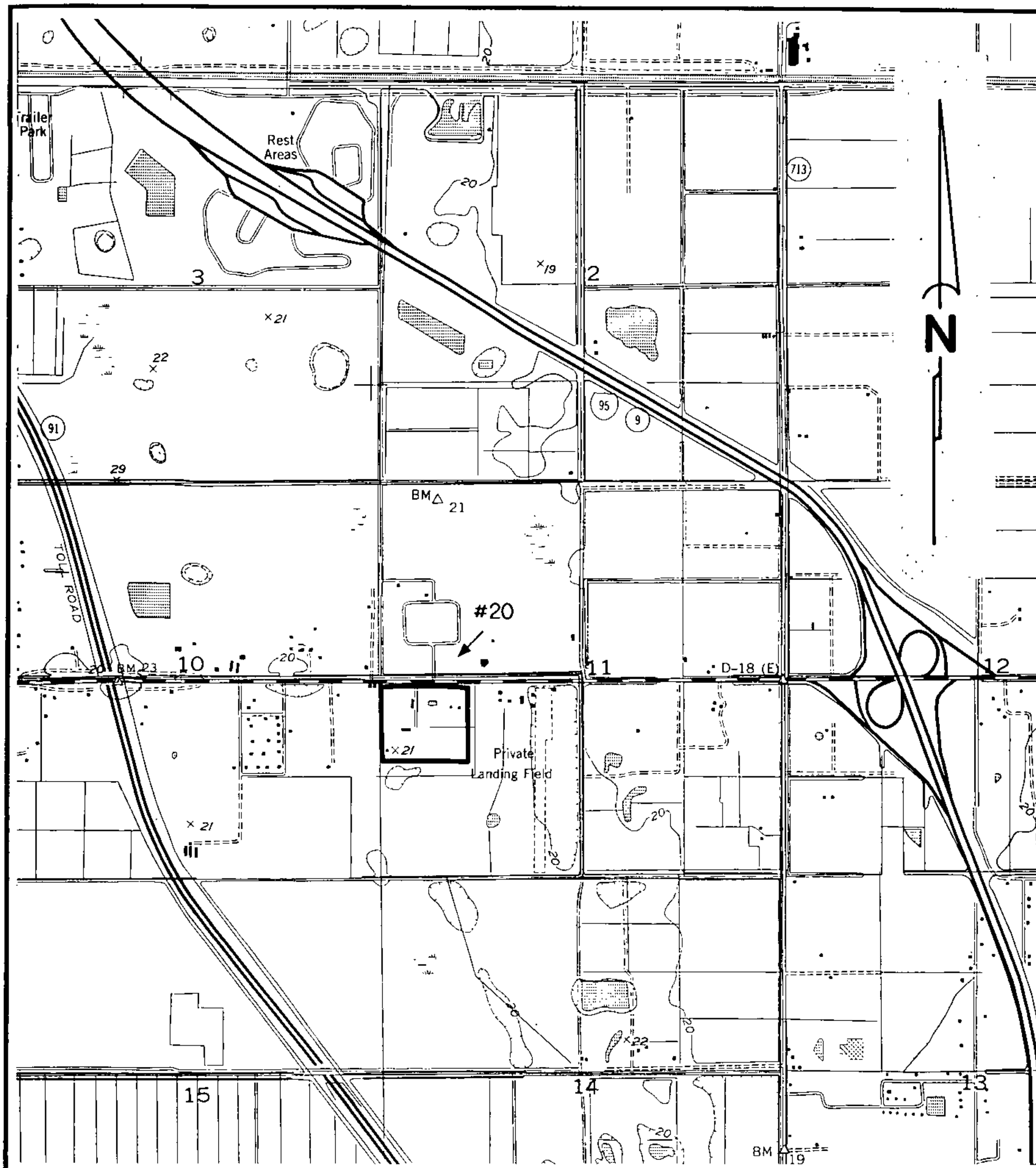
FIGURE 1-1
FGTC'S GAS TRANSMISSION SYSTEM
FLORIDA GAS TRANSMISSION COMPANY
FLORIDA

DRAWN: SJF/SH	DATE: 2-11-93	PROJECT NUMBER.
APPV'D:	REVISED 2-26-93	6792-068-035



0 2000 4000

SCALE IN FEET

REFERENCE: U.S.G.S. Quadrangle Map for Fort Pierce NW, Florida, 1983.

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FIGURE 1-2

SITE LOCATION MAP

COMPRESSOR STATION #20

FLORIDA GAS TRANSMISSION COMPANY

FT. PIERCE, FLORIDA

DRAWN BY: SJF/SH	DATE: 12-16-92	PROJECT NUMBER: 6792-068-035
CHK'D.BY:	REVISED:	

TOPO

approval authority in Florida. Based on the proposed emissions from the addition of the one 4,000 bhp IC engine, a PSD review is required for NO_x.

Engineering designs for the proposed expansion project include selection of an engine incorporating lean-burn technology. Lean-burn technology for emission control represents Best Available Control Technology (BACT) for the proposed IC engine.

This application contains six additional sections. Descriptions of the existing operation at FGTC's Compressor Station No. 20, and the one (1) proposed, 4,000 bhp engine to be added to the station, are presented in Section 2.0. The air quality review requirements and applicability of state and federal regulations to the proposed project are discussed in Section 3.0. The methodology and results of the air dispersion modeling and air quality impact analysis are presented in Section 4.0, and impacts on soil, vegetation and visibility are summarized in Section 5.0. The BACT analysis required as part of the PSD permitting process is presented in Section 6.0. References cited in this document are included in Section 7.0.

FDER permit application forms are presented in Appendix A. Additional appendices contain information which support the representations made in this application.

2.0 PROJECT DESCRIPTION

A plot plan of FGTC's Compressor Station No. 20, showing the location of the plant boundaries, the existing emission sources, and the location of the proposed engine addition, is presented in Appendix B. The following sections provide a description of the existing operations at this location, as well as the proposed project.

2.1 Existing Operations

FGTC's existing Compressor Station No. 20 consists of two (2) 1,500 bhp, one (1) 2,000 bhp, and (1) 2,400 bhp, natural-gas-fired, reciprocating, IC engines. Table 2-1 summarizes engine manufacturer, model, and dates of installation for each of the existing engines. The original installation was made in 1966 (Compressor Engine Nos. 2001, and 2002). A later installation was made in 1968 (Compressor Engine No. 2003). These engines were all installed before the CAA Amendments of 1977. An addition referred to as "Phase II" was constructed in 1991 (Compressor Engine No. 2004). These existing engines are not being modified as part of this expansion project.

2.2 Proposed Compressor Station Addition

As part of the Phase III project, FGTC proposes to increase the horsepower capacity of Compressor Station No. 20. This will be achieved by adding one new IC engine (Compressor Engine No. 2005) and associated support equipment. The proposed new engine will be used to drive a gas compressor that is a part of a new gas transmission line that will transport natural gas from source wells in Texas and Louisiana for delivery throughout the Gulf Coast pipeline network. Without the proposed engine, it would not be possible to increase the volumetric delivery capacity necessary to meet both short- and long-term demands for natural gas along the Gulf Coast.

2.2.1 Compressor Engine Addition

The new engine will be a Cooper-Bessemer 10V-275C engine compressor unit. The engine has 10 power cylinders and is rated at 4,000 bhp at 275 revolutions per minute (rpm). A flow diagram of a typical compressor unit is presented in Figure 2-1. Fuel will be exclusively natural gas from the FGTC's gas pipeline. Engine specifications and stack parameters for the proposed engine are presented in Table 2-2. The proposed engine will incorporate lean-burn technology.

TABLE 2-1

Summary of Existing Engine Information
Compressor Station No. 20

Engine No.	Date of Installation	Type	Manufacturer	Model No.	Brake Horse Power (bhp)
2001	1966	Reciprocating	Worthington	SEHG-6	1500
2002	1966	Reciprocating	Worthington	SEHG-6	1500
2003	1968	Reciprocating	Worthington	SEHG-8	2000
2004	1991	Reciprocating	Dresser - Rand	412-KVSR	2400

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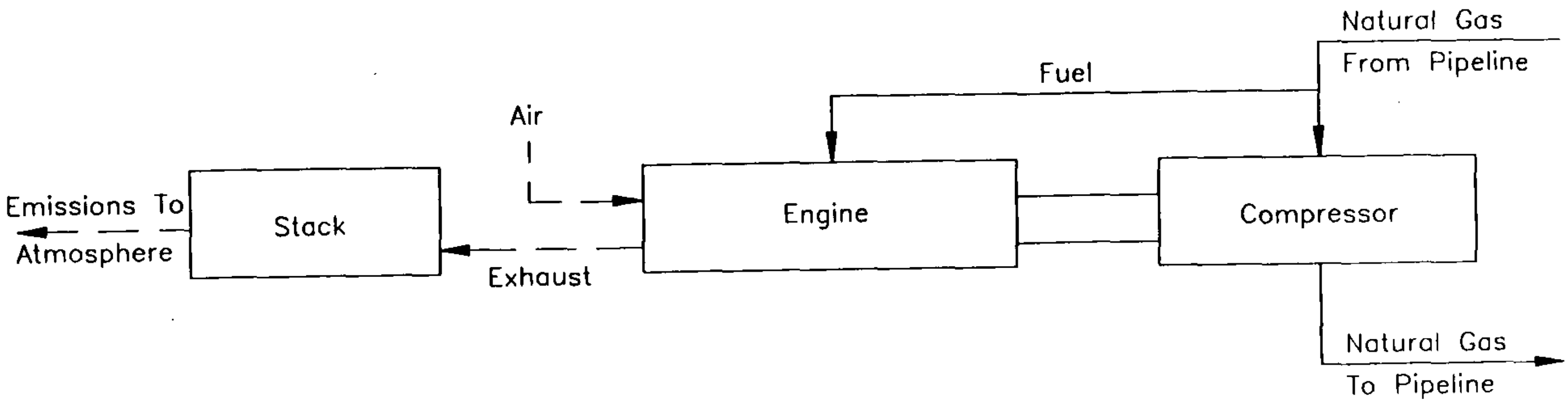

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FIGURE 2-1
PROCESS FLOW DIAGRAM
OF AN
ENGINE-COMPRESSOR UNIT

DRAWN: DC/SH	DATE: 11-6-92	PROJECT NUMBER:	
APPV'D:	REVISED: 3-16-93	6792-068	

TABLE 2-2

Engine Specifications and Stack Parameters for the Proposed Project

Parameter	Design Specification
Compressor Engine	2005
Type	Reciprocating Engine
Manufacturer	Cooper-Bessemer
Model	10V-275C
Air Charging	Turbocharged
Unit Size	4,000 bhp
Number of Power Cylinders	10
Number of Compressor Cylinders	4
Power Cylinder Data	
Bore Size	18.0 inches
Stroke	20.0 inches
Cylinder Power	400 bhp
Specific Heat Input	6,950 Btu/bhp-hr Nominal
	-7,650 Btu/bhp-hr (Maximum)
Maximum Fuel Consumption	0.0294 MMscf/hr
Speed	275 rpm
Stack Parameters	
Stack Height	65 ft
Stack Diameter	4 ft
Exhaust Gas Flow	34,928 acfm
Exhaust Temperature	540°F
Exhaust Gas Velocity	47.31 ft/sec.

NOTE:
acfm = actual cubic feet per minute.
bhp = brake horsepower.
Btu/bhp-hr = British thermal units per brake horsepower per hour.
°F = degrees fahrenheit.
ft = feet.
ft/sec = feet per second.
lb/hr = pounds per hour.
scf = standard cubic feet.
MMscf/hr = million standard cubic feet per hour.
rpm = revolutions per minute.

[a] Based on heating value for natural gas of 1,040 British thermal units per standard cubic foot (Btu/scf).

Hourly and annual emissions of regulated pollutants from the proposed engine, under normal operating conditions, are presented in Table 2-3. The table also includes the maximum hourly emissions which can be expected from this proposed class of engine. These maximum values represent the highest emission rate a unit could produce under any operating condition. It should be noted that these highest emission rates would only occur for short periods, under extreme load and weather conditions, which are unlikely to be encountered at this compressor station. They have been included to ensure the facility is properly permitted. Emissions of oxides of nitrogen (NO_x), carbon monoxide (CO), and non-methane hydrocarbons (NMHC) are based on engine manufacturer's supplied data (See Appendix C).

Typically, IC engine vendors do not provide information on particulate matter (PM) or sulfur dioxide (SO_2) emissions. Therefore, PM emissions are based upon USEPA publication AP-42 (USEPA, 1985) emission factors for natural gas combustion in boilers, and emissions of SO_2 are based on FGTC's natural gas contract limits of 10 grains sulfur per 100 cubic feet of gas.

2.2.2 Support Equipment Additions

In addition to the compressor engine, some support equipment will be installed at the site. This added support equipment will include:

- A new compressor building
- A 625-bhp natural gas fired emergency stand-by generator

The location of the new on-site structure is shown on the facility plot plan contained in Appendix B. The new compressor building, housing the new engine, has approximate dimensions of 60 feet wide by 72 feet long by 41 feet high.

The control and operation of a compressor station requires a steady electrical power supply. As there is potential for local utility service to be disrupted, FGTC must maintain a backup power system. To meet this need at Compressor Station No. 20, a 625-bhp (450 kw) natural-gas-fired emergency stand-by generator will be installed at the site. To control emissions the new generator will be equipped with a catalytic converter. The converter is 90% effective on NO_x, 80% effective on CO and 50% effective on NMHC.

TABLE 2-3

Emissions from FGTC's Proposed Compressor Engine

Pollutant	Emission Factor	Reference	Maximum Emissions		
			Maximum lb/hr	Nominal lb/hr	TPY
Nitrogen Oxides	2.00 grams/bhp-hr	Manufacturer Data	52.92	17.64	77.26
Carbon Monoxide	2.10 grams/bhp-hr	Manufacturer Data	26.46	18.52	81.12
Volatile Organic Compounds (non-methane)	0.60 grams/bhp-hr	Manufacturer Data	12.35	5.29	23.18
Particulate Matter	0.015 grams/bhp-hr	AP-42 (factor of 5 lb/MMscf)	0.15	0.13	0.57
Sulfur Dioxide	0.086 grams/bhp-hr	10 grains/100 scf	0.84	0.76	3.33

NOTE:

Maximum natural gas consumption is 29,400 standard cubic feet per hour (scf/hr).

grams/bhp-hr = grams per brake horsepower per hour.
grains/100scf = grains per one hundred standard cubic feet.
lb/hr = pounds per hour.
lb/MMscf = pounds per million standard cubic feet.
scf = standard cubic feet.
TPY = tons per year.

The hourly and annual emissions from this unit are presented in Table 2-4. Hourly emissions were calculated from manufacturer's data in a manner similar to the calculations for main compressor engines. Annual emissions reflect a 400-hour-per-year operational restriction. Detailed emission calculations are presented in Appendix D.

2.2.3 Fugitive Emissions

Potential new emissions from Compressor Station No. 20 include fugitive emissions from the new valves and flanges to be in gas service. These fugitive emissions have been estimated using USEPA factors for components in gas service. Table 2-5 lists the quantities of existing and new components to be installed as part of the Phase III project and an estimate of the fugitive emissions from these sources.

2.2.4 Emissions Summary

The total change in emissions resulting from the proposed project are listed in Table 2-6. The calculations used to estimate these emissions are presented in Appendix D.

TABLE 2-4

Emissions from FGTC's Proposed Emergency Electrical Generator

Pollutant	Emission Factor	Reference	Emissions	
			lb/hr	TPY
Nitrogen Oxides	0.98 grams/bhp-hr	Manufacturer Data	1.35	0.27
Carbon Monoxide	2.14 grams/bhp-hr	Manufacturer Data	2.95	0.59
Volatile Organic Compounds (non-methane)	0.04 grams/bhp-hr	Manufacturer Data	0.055	0.011
Particulate Matter	0.018 grams/bhp-hr	AP-42 (factor of 5 lb/MMscf)	0.025	0.005
Sulfur Dioxide	0.10 grams/bhp-hr	10 grains/100 scf	0.14	0.028

NOTE:

Emission calculations based on unit operating a maximum of 400 hours per year.
Maximum natural gas consumption is 5,038 standard cubic feet per hour (scf/hr).

grams/bhp-hr = grams per brake horsepower per hour.
grains/100scf = grains per one hundred standard cubic feet.
lb/hr = pounds per hour.
lb/MMscf = pounds per million standard cubic feet.
scf = standard cubic feet
TPY = tons per year.

TABLE 2-5
FGTC's Compressor Station No. 20
Fugitive VOC's Emission Calculation
and Summary

COMPONENT TYPE	SERVICE	COMPONENT COUNT	EMISSION FACTORS	NM/NE* FRACTION	EMISSIONS LBS/HR	EMISSIONS LBS/DAY	EMISSIONS TONS/YR
CURRENT:							
Valve	Gas	136	1.06 Lbs/Day (a)	0.005	0.030	0.72	0.13
Flange	Gas	308	0.57 Lbs/Day (a)	0.005	0.037	0.88	0.16
Compressor Seal	Gas	4	39.7 Lbs/Day (a)	0.005	0.033	0.79	0.14
				Total	0.100	2.39	0.44
PROJECT ADDED:							
Valve	Gas	26	1.06 Lbs/Day (a)	0.005	0.006	0.14	0.03
Flange	Gas	75	0.57 Lbs/Day (a)	0.005	0.009	0.21	0.04
Compressor Seal	Gas	1	39.7 Lbs/Day (a)	0.005	0.008	0.20	0.04
				Total	0.023	0.55	0.10
FUTURE: (b)							
Valve	Gas	162			0.036	0.86	0.16
Flange	Gas	383			0.045	1.09	0.20
Compressor Seal	Gas	5			0.041	0.99	0.18
				Total:	0.123	2.94	0.54

Notes: (a) – EPA-450/3-83-007, page 3-9
(b) – Future = current + project added
* – NM/NE = non-methane/non-ethane

TABLE 2-6

Annual (TPY) Emission Levels
FGTC's Compressor Station No. 20

SOURCE ID	DESCRIPTION	NO_x	CO	VOC (NM/NE HC)	SO_2	PM
EXISTING FACILITY						
	COMPRESSOR ENGINES:					
2001	1500 bhp Recip. Engine	159.36	20.28	6.37	1.34	0.23
2002	1500 bhp Recip. Engine	159.36	20.28	6.37	1.34	0.23
2003	2000 bhp Recip. Engine	212.47	27.04	8.50	1.79	0.31
2004	2400 bhp Recip. Engine	49.36	64.90	39.40	2.09	0.41
	OTHER SOURCES: *	—	—	2.89	—	—
EXISTING TOTAL		580.55	132.50	63.53	6.56	1.18
PROJECT RELATED						
	COMPRESSOR ENGINE:					
2005	4000 bhp Recip. Engine	77.26	81.12	23.18	3.33	0.57
2011	EMERGENCY GENERATOR	0.27	0.59	0.01	0.03	0.01
	FUGITIVE	—	—	0.10	—	—
PROJECT TOTAL		77.53	81.71	23.29	3.36	0.58
STATION TOTAL **		658.08	214.21	86.82	9.92	1.76

* - Other Sources includes; ancillary equipment, storage tanks and equipment leaks.
** - STATION TOTAL = EXISTING + PROJECT

3.0 REGULATORY ANALYSIS

This section presents a review of federal and Florida state air quality regulations which govern the operations to be conducted at Compressor Station No. 20.

3.1 Federal Regulatory Review

The federal regulatory programs administered by the USEPA have been developed under the authority of the Clean Air Act. The following subsections review the key elements of the federal regulatory program and the impact they have on operations at Compressor Station No. 20. Special attention will be placed on National Ambient Air Quality Standards (AAQS) (40 CFR 50), New Source Performance Standards (NSPS) (40 CFR 60), National Emission Standards for Hazardous Air Pollutants (NESHAPS) (40 CFR 61), and Prevention of Significant Deterioration (PSD) (40 CFR 52.21).

3.1.1 Classification of Ambient Air Quality

The 1970 Amendments to the CAA gave the USEPA specific authority to establish the minimum level of air quality which all states would be required to achieve. These minimum values or standards were developed to protect the public health (primary) and welfare (secondary). The federally promulgated standards and additional state standards, are presented on Table 3-1.

Areas of the country which have air quality equal to or better than these standards (i.e., ambient concentrations less than a standard) became designated as "Attainment Areas", while those where monitoring indicated air quality was less than the standards became known as "Non-attainment Areas." The designation of an area has particular importance for a proposed project as it determines the type of permit review to which the application will be subject.

Major new sources or major modifications to existing major sources located in attainment areas are required to obtain a PSD permit prior to initiation of construction. Similar sources located in or near areas designated as Non-attainment or that adversely impact such areas, will undergo more stringent New Source Review (NSR). In either case it is necessary, as a first step, to determine the air quality classification of a project site.

TABLE 3-1

NATIONAL AND STATE AMBIENT AIR QUALITY STANDARDS
($\mu g/m^3$)

	AVERAGING PERIOD	EPA STANDARDS		FLORIDA STANDARDS
		PRIMARY	SECONDARY	
PM_{10}	24-hour(1)	150	150	150
	annual(2)	50	50	50
SO_2	3-hour(1)	---	1,300	1,300
	24-hour(1)	365	---	260
	annual(2)	80	---	60
CO	1-hour(1)	---	40,000	40,000
	8-hour(1)	10,000	---	10,000
NO_2	annual(2)	100	100	100
O_3	1-hour(3)	235	235	235

(1) Not to be exceeded more than once per year.
(2) Never to be exceeded.
(3) Not to be exceeded more than 3 days over 3 years.

Source: 40 CFR 50; 36FR22384; §17-2.300 F.A.C.

The 1990 CAA Amendments called for a review of the ambient air quality of all regions of the United States. States were required to file with the USEPA by March 15, 1991, designations of all areas as either attainment, non-attainment or unclassifiable. The current classification of St. Lucie County is listed below on Table 3-2, for each criteria pollutant. St. Lucie County is designated as Better than Standards for SO_2 and TSP, Unclassifiable/Attainment for CO and ozone, cannot be classified for NO_x, and has not been classified for PM_{10}. These designations were obtained from 40 CFR 81, as updated in the November 6, 1991, Federal Register (56FR56694).

The designation of Unclassifiable/Attainment indicates that there is insufficient monitoring data to prove that the area has attained the federal standards: however, the limited data available indicates that the standard has been achieved. Areas with this classification are treated as attainment areas for permitting purposes.

3.1.2 PSD Applicability

The 1977 CAA Amendments added Part C - Prevention of Significant Deterioration to the Act. This part requires proposed new major stationary sources or existing sources planning a major modification in an area that has attained the National AAQS, to conduct a preconstruction review of the project that includes a detailed analysis of the emissions it would generate, available emission control technology, and project related impacts.

Federal air quality permitting regulations for attainment areas are codified in the Code of Federal Regulations (CFR), Title 40 - Protection of the Environment, Part 52.21 - Prevention of Significant Deterioration (40 CFR 52.21). While the portion of the Florida State Implementation Plan (SIP) related to PSD regulations has been approved by the USEPA, and authority for the program has been transferred to the state, the applicability of the program to Compressor Station No. 20 will be reviewed in this section, as it remains primarily a federal program.

For the PSD regulations to apply to a given project, the proposed location must be in a PSD area, i.e., an area that has been classified as attainment or as unclassifiable for a particular pollutant. The project's potential to emit is then reviewed to determine whether it constitutes a major stationary source or major modification.

A major stationary source is defined as either one of the 28 sources identified in 40 CFR 52.21 (see Table 3-3) and which has a potential to emit 100 tons or more per year of any regulated pollutant, or any other stationary source which has the potential to emit 250 tons or more per year of a regulated pollutant. "Potential to emit" has a special meaning here as it is determined

TABLE 3-2

Classification of St. Lucie County For Each Criteria Pollutant

Carbon Monoxide	Unclassifiable/Attainment
Oxides of Nitrogen	Cannot be Classified or Better than National Standards
Sulfur Dioxide	Better than Standards
Particulate Matter (PM_{10})	Not Designated
Total Suspended Particulate	Better than Standards
Ozone	Unclassifiable/Attainment
Source: 40 CFR 81.300, 1991 56FR56694	

TABLE 3-3

Major Stationary Sources

Fossil Fuel-Fired Steam Electric Plants of More Than 250,000,000 British Thermal Units Per Hour Heat Input
Coal Cleaning Plants (with thermal dryers)
Kraft Pulp Mills
Portland Cement Plants
Primary Zinc Smelters
Iron and Steel Mill Plants
Primary Aluminum Ore Reduction Plants
Primary Copper Smelters
Municipal Incinerators Capable of Charging More Than 250 Tons of Refuse Per Day
Hydrofluoric, Sulfuric or Nitric Acid Plants
Petroleum Refineries
Lime Plants
Phosphate Rock Processing Plants
Coke Oven Batteries
Sulfur Recovery Plants
Carbon Black Plants
Primary Lead Smelters
Fuel Conversion Plants
Sintering Plants
Secondary Metal Production Plants
Chemical Processing Plants
Fossil-Fuel Boilers (or combination thereof) Totaling of More Than 250,000,000 British Thermal Units Per Hour Heat Input
Petroleum Storage and Transfer Units With a Total Storage Capacity Exceeding 300,000 Barrels
Taconite Ore Processing Plants
Glass Fiber Processing Plants
Charcoal Production Plants
Source: 40 CFR 51.165(a)(iv)(2)(c)

on an annual basis after the application of air pollution control equipment, or any other federally enforceable restriction.

According to the "PSD Workshop Manual," (USEPA, 1980) for a modification to be classified as major and therefore, subject to PSD review:

(1) the modification must occur at an existing major stationary source, and

(2) the net emissions increase of any pollutant emitted by the source, as a result of modification is "significant," or

(3) the modification results in emissions increases which if considered alone would constitute a major source.

"Significant" emission rates are defined as amounts equal to or greater than the emission rates given in Table 3-4.

By this definition, and based on the emissions presented in Section 2.0, Compressor Station No. 20 is an existing major stationary source due to emissions of nitrogen oxides. Even though the new engine is not listed as one of the 28 named source categories, based on emissions presented in Section 2.0, installation of the new engine will require a PSD review because the net increase in NO_x emissions is significant (see Table 3-4) at this existing major source (Compressor Station No. 20).

PSD review is used to determine whether significant air quality deterioration will result from the new or modified facility. Major new facilities and major modifications are required to undergo the following analyses and reviews related to PSD for each pollutant emitted in significant amounts:

- Control Technology Review
- Source Impact Analysis
- Air Quality Analysis (monitoring)
- Source Information
- Additional Impact Analyses
- Good Engineering Practice (GEP) Stack Height Analysis.

Discussions concerning each of these requirements are presented in the following sections.

TABLE 3-4

PSD Significant Emission Rates

POLLUTANT	EMISSION RATE TONS/YEAR
Carbon Monoxide	100
Nitrogen Oxides	40
Sulfur Dioxide	40
Total Suspended Particulates	25
Ozone (VOC)	40
Lead	0.6
Asbestos	0.007
Beryllium	0.0004
Mercury	0.1
Vinyl Chloride	1.0
Fluorides	3
Sulfuric Acid Mist	7
Total Reduced Sulfur	10
Reduced Sulfur	10
Hydrogen Sulfide	10
VOC = Volatile Organic Compound	

3.1.2.1 Increments/Classifications

In 1977, USEPA promulgated PSD regulations related to the requirements for classifications, increments, and area designations as set forth by Congress. PSD increments were initially set for only SO_2 and Total Suspended Particulates (TSP). However, in 1988, USEPA promulgated final PSD regulations for nitrogen oxides (NO_x) and established PSD increments for nitrogen dioxide (NO_2). On October 15, 1989, USEPA proposed PSD increments for PM_{10}. The PM_{10} increments are somewhat lower in magnitude than the TSP increments.

An area is designated as being Class I, II, or III depending on the criteria listed in Table 3-5.

The current federal PSD increments for different area classifications are shown in Table 3-6. Class I increments are the most stringent, allowing the smallest amount of air quality deterioration, while the Class III increments allow the greatest amount of deterioration. Florida Department of Environmental Regulation (FDER) has adopted the USEPA class designations and allowable PSD increments for TSP, SO_2, and NO_2.

The term "baseline concentration" evolved from federal and state PSD regulations and refers to a concentration level corresponding to a specified baseline date and certain additional baseline sources. By definition in the PSD regulations, baseline concentration means the ambient concentration level that exists in the baseline areas 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:

- The actual emissions representative of sources in existence on the applicable baseline date; and

- The allowable emissions of major stationary sources that began construction before January 6, 1975, for SO_2 and TSP sources, or February 8, 1988, for NO_x sources; but which 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:

- Actual emissions from any major stationary source on which construction began after January 6, 1975, for SO_2 and TSP sources, and after February 8, 1988, for NO_x sources; and

TABLE 3-5

PSD Area Class Definitions

<u>CLASS I</u> All of the following areas which were in existence on August 7, 1977, shall be Class I and may not be redesignated: • International parks • National wilderness areas which exceed 5,000 acres in size • National memorial parks which exceed 5,000 acres in size, and • National parks which exceed 6,000 acres in size Areas which were redesignated as Class I under regulations promulgated before August 7, 1977, shall remain Class I, but may be redesignated
<u>CLASS II</u> Any other area, unless otherwise specified in the legislation creating such area, is initially designated Class II, but may be redesignated.
<u>CLASS III</u> Any area other than Class I areas for which a request for redesignation has been received may be designated as Class III. The following areas may be redesignated only as Class I or II: • An area as of August 7, 1977, exceeding 10,000 acres in size and which was a national monument, a national primitive area, a national preserve, a national recreation area, a national wild and scenic river, a national wildlife refuge, a national lakeshore or seashore; and • A national park or national wilderness area established after August 7, 1977, which exceeds 10,000 acres in size.
Source: 40 CFR 52.21

TABLE 3-6

ALLOWABLE PSD INCREMENTS AND IMPACT SIGNIFICANCE LEVELS ($\mu g/m^3$)

Pollutant	Averaging Time	PSD Increments*		Significant Impact Levels
		Class I	Class II	
Particulate Matter (TSP)	Annual Geometric Mean	5	19	1
	24-hour Maximum	10	37	5
Particulate Matter (PM_{10})	Annual Arithmetic Mean	4[a]	17[a]	1
	24-hour Maximum	8[a]	30[a]	5
Sulfur Dioxide	Annual Arithmetic Mean	2	20	1
	24-hour Maximum	5	91	5
	3-hour Maximum	25	512	25
Carbon Monoxide	8-hour Maximum	NA	NA	500
	1-hour Maximum	NA	NA	2,000
Nitrogen Dioxide	Annual Arithmetic Mean	2.5	25	1

[a] Proposed by EPA in the Federal Register on October 5, 1989.

Note: Particulate Matter (TSP) = total suspended particulate matter.
Particulate Matter (PM_{10}) = particulate matter with aerodynamic diameter $\leq$10 mμ
$\mu g/m^3$ = micrograms per cubic meter
NA = Not applicable, i.e., no standard exists.

Source: Federal Register, Vol 43, No. 118, June 19, 1978; 40 CFR 50; 40 CFR 52.21; F.A.C. Chap. 17-2.400.

* No Class III areas have been designated; therefore, there are no Class III Increments.

- Actual emission increases and decreases at any stationary source occurring after the baseline date.

If air quality impacts of a project are less than the significant impact levels presented in Table 3-6, increment consumption is not considered.

The minor source baseline date for SO_2 and TSP has been set as December 27, 1977, for the entire state of Florida (Chapter 17-2.450, F.A.C.). The minor source baseline date for NO_2 has been set as March 28, 1988, for all of Florida.

3.1.2.2 Control Technology Review

The control technology review requirements of the federal and state PSD regulations require that all applicable federal and state emission limiting standards be met and that BACT be applied to control emissions from the source [Chapter 17-2.500(5)(c), F.A.C.]. The BACT requirements are applicable to all regulated pollutants for which the increase in emissions from the facility or modification exceeds the significant emission rate (see Table 3-4).

The requirements for BACT were promulgated within the framework of PSD in the 1977 amendments of the CAA. 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 prepared 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 since BACT analyses must be conducted on a case-by-case basis (USEPA, 1980).

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 in light of existing and future air quality in the vicinity of the proposed facility. BACT must, as a minimum, demonstrate compliance with New Source Performance Standards (NSPS) for a source (if applicable). An evaluation of the air pollution control techniques and systems is required. The evaluation is to include a cost-benefit analysis of alternative control technologies capable of achieving a higher degree of emission reduction than the proposed control technology. 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 judgment, balancing environmental benefits with energy, economic, and other impacts (USEPA, 1978).

Historically, a "bottom-up" approach consistent with the BACT Guidelines and "PSD Workshop Manual" has been used. With this approach, an initial control level, which is usually NSPS, is evaluated against successively more stringent controls until a BACT level is selected. However, USEPA developed a concern that the bottom-up approach was not providing the level of BACT decisions originally intended. As a result, in December 1987, the USEPA Assistant Administrator for Air and Radiation mandated the adoption of a new "top-down" approach to BACT decision making.

The top-down BACT approach starts with the most stringent (or top) technology and emissions limit that has been applied elsewhere to the same or a similar source category. The applicant must next provide a basis for rejecting this technology in favor of the next most stringent technology or propose to use it. Rejection of control alternatives may be based on technical or economic infeasibility. Such decisions are made on the basis of physical differences (e.g., fuel type), locational differences (e.g., availability of water), or significant differences that may exist in the environmental, economic or energy impacts. The differences between the proposed facility and the facility on which the control technique was applied previously must be justified. Recently, USEPA issued a draft guidance document on the top-down approach entitled "Top-Down Best Available Control Technology Guidance Document" (USEPA, 1990a).

A top-down BACT analysis is presented in Section 6.0, Best Available Control Technology.

3.1.2.3 Air Quality Monitoring Requirements

In accordance with requirements of 40 CFR 52.21(m) and Chapter 17-2.500(f), F.A.C., any application for a PSD permit must contain an analysis of ambient air quality data in the area affected by any criteria pollutant emitted in significant rates by the proposed major stationary source or major modification.

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. Ambient air monitoring for a period of up to one year is generally appropriate to satisfy the PSD monitoring requirements. A minimum of four months of data is required. Guidance in designing a PSD monitoring network is provided in USEPA's "Ambient Monitoring Guidelines for Prevention of Significant Deterioration" (USEPA, 1987a).

Under the exemption rule, FDER may exempt a proposed PSD source from the monitoring requirements for a particular pollutant if the air quality impacts are less than the *de minimis* levels presented in Table 3-7 [Chapter 17-2.500(3)(e), F.A.C.].

Impacts resulting from the proposed project presented in Section 4.0 indicate impacts will be well below the *de minimis* level and no monitoring is required.

3.1.2.4 Source Impact Analysis

A source impact analysis must be performed for a proposed major source subject to PSD for each pollutant for which the increase in emissions exceeds the significant emission rate (Table 3-4). The PSD regulations specifically provide for the use of atmospheric dispersion models in performing the 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" (USEPA, 1987b). The source impact analysis for criteria pollutants may be limited to only the new or modified source if the net increase in impact due to the new or modified source is below significance levels, as presented in Table 3-6.

Various lengths of record for meteorological data can be utilized for the 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" (HSH) 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 five 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. Impacts resulting from the proposed project are presented in Section 4.0, Air Quality Impact Analysis.

3.1.2.5 Additional Impact Analyses

In addition to an air quality impact analysis, federal and Florida PSD regulations require analysis of the impairment to visibility and the impacts on soils and vegetation that would occur as a result of the proposed source [40 CFR 52.21; Chapter 17-2.500(5)(e), F.A.C.]. 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.

TABLE 3-7

De Minimis Monitoring Concentrations

Pollutant	De Minimis Monitoring Concentration ($\mu g/m^3$)
Carbon Monoxide	575, 8-hour
Nitrogen Oxides	14, annual
Sulfur Dioxide	13, 24-hour
Total Suspended Particulates	10, 24-hour
Ozone (VOC)	100 TPY[a]
Lead	0.1, 3-month
Asbestos	NM
Beryllium	0.001, 24-hour
Mercury	0.25, 24-hour
Vinyl Chloride	15, 24-hour
Fluorides	0.25, 24-hour
Sulfuric Acid Mist	NM
Total Reduced Sulfur	10, 1-hour
Reduced Sulfur	10, 1-hour
Hydrogen Sulfide	0.2, 1-hour

[a] No de minimis concentration; an increase in VOC emissions of 100 TPY or more will require monitoring analysis for ozone.
NM = no ambient measurement method.
$\mu g/m^3$ = micrograms per cubic meter.
VOC = Volatile Organic Compound.
Sources: 40 CFR 52.21; Chapter 335-3-14-.04, A.A.C.

These analyses are required for each pollutant emitted in significant amounts (Table 3-6). These analyses are presented in Section 5.0, Soils, Vegetation, Visibility, and Associated Population Growth Impacts.

3.1.2.6 Good Engineering Practice (GEP) Stack Height Analysis

The 1977 CAA Amendments require that the degree of emission limitation required for control of any pollution not be affected by a stack which exceeds GEP height. Further, no dispersion credit is given during air quality modeling for stacks which exceed GEP. GEP stack height is defined as the highest of:

- 65 meters; or
- a height established by applying the formula

  $H_{GEP} = H + 1.5\,L$

  Where; H_{GEP} = GEP Stack Height,
  H = Height of the structure or nearby structure, and
  L = Lesser dimension (height or projected width) of the nearby structure or,

- a height demonstrated by fluid modeling or field study.

A structure or terrain feature is considered nearby if a stack is within a distance of five times the structure's height or maximum projected width. Only the smaller value of the height or projected width is used and the distance to the structure cannot be greater than 0.8 kilometers. Although GEP stack height regulations require that the stack height used in modeling for determining compliance with National AAQS and PSD increments not exceed GEP stack height, the actual stack height may be greater.

The stack height regulations also increase GEP stack height beyond that resulting from the formula in cases where plume impaction occurs. Plume impaction is defined as concentrations measured or modeled 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 terrain in the vicinity of the project site is generally flat, plume impaction was not considered in determining the GEP stack height.

The proposed stack at Compressor Station No. 20 will be 65 feet (19.8 meters) tall. Based on the proposed building dimensions, the calculated GEP stack height is less than 65 meters;

therefore, GEP stack height is 65 meters. Since the stack is less than GEP stack height, it complies with the regulatory requirement.

3.1.3 Non-Attainment New Source Review (NSR) Rules

Based on the current non-attainment provisions, all new major stationary sources, or modifications to such sources, located in a non-attainment area must undergo non-attainment New Source Review, if they have the potential to emit above an NSR significant threshold. For major new sources or major modifications that locate in an attainment or unclassifiable area, the non-attainment provisions will also apply if the source or modification is located within the area of influence of a non-attainment area. The area of influence is defined as an area which is outside the boundary of a non-attainment area but within the locus of all points that are 50 km outside the non-attainment area. Based on Chapter 17-2.510(2)(a)2.a, F.A.C., all volatile organic compound sources which are located within an area of influence are exempt from the provisions of new source review for non-attainment areas.

Compressor Station No. 20 is located in an area classified as either attainment or unclassifiable for all criteria pollutants. Therefore, installation of the new IC engine at this compressor station is not subject to federal non-attainment New Source Review.

3.1.4 Applicability of New Source Performance Standards (NSPS)

The regulation of new sources through the development of standards applicable to a specific category of sources was a significant step taken by the 1970 CAA Amendments. The Administrator was directed to prepare and publish a list of stationary source categories which, in the Administrator's judgement, cause or contribute significantly to air pollution and which may reasonably be anticipated to endanger public health. Further, the Administrator was to publish a proposed regulation establishing a Standard of Performance for any new source which fell into that category. The significant feature of the Section was that it would apply to all sources within a given category, regardless of its geographic location or the ambient air quality at that location. The standards, in essence defined emission limitations that would be applicable to a particular source group.

A portion of Section 111 of the Act requires states to develop their own set of performance standards. State standards apply to existing sources and only to those pollutants for which air quality criteria had not been developed or were not covered by either Section 108 or 112 of the Act. Additionally, the states could regulate any source whether it was covered by a federally designated source category or not. It is clear that Congress wanted to give the states specific authority to regulate existing sources which would, otherwise, only be subject to the provisions of Section 111 if they were new. New Source Performance Standards promulgated by the state of Florida are discussed in Section 3.2 and Appendix E.

Currently, there are 66 separate performance standards published in 40 CFR 60. The new compressor engine to be installed at Compressor Station No. 20 is not subject to any listed standard.

3.1.5 Applicability of National Emission Standards for Hazardous Air Pollutants (NESHAP)

Realizing that there were numerous pollutants that did not meet the specific criteria for development of a National AAQS, Congress included Section 112 in the 1970 amendments which specifically addressed this problem. Section 112 provides the USEPA with a vehicle for developing standards for potentially hazardous pollutants.

During the development of the 1970 CAA Amendments, the Senate prepared a report identifying many such compounds which were to be considered for regulation under the new section. The 1990 CAA Amendments significantly expanded the number of compounds to be regulated under Section 112. Under the current provisions of the Act, 189 compounds or classes of compounds are to be regulated under Section 112 by November 15, 2000.

The regulations which were developed to implement Section 112 are presented in 40 CFR, Part 61. This part contains a listing of those pollutants that have been designated as being hazardous (Part 61.01) as defined in Section 112, and standards applicable to specific industries. Unlike the New Source Performance Standards, this Section is applicable to new and existing sources that emit pollutants subject to the Section. None of the promulgated standards currently apply to Compressor Station No. 20.

3.2 Florida State Air Quality Regulations

Title 17, F.A.C., contains the environmental rules and regulations for the State of Florida. The primary federal regulations which affect Compressor Station No. 20 have been incorporated, for the most part in whole, into the Florida state regulations. Specific air quality regulations of the State of Florida are too numerous to discuss in detail in this section, however, an applicability review was performed during the preparation of this document. The results of this review are presented in Appendix E. Compressor Station No. 20 will operate in compliance with all applicable Florida state regulations as documented in Appendix E.

4.0 AIR QUALITY IMPACT ANALYSIS

The FDER, Air Quality Division, requires that an ambient air quality impact analysis be performed on a proposed project's emissions. For State Authority to Construct permits, this involves comparison of the project's impact to the State and National AAQS, discussed in Section 3.0 of this report. For PSD, additional assessments of increment consumption and impacts on Class I areas must also be conducted. The following section outlines the general approach used for these analyses. This approach was developed in consultation with the FDER and The Guideline on Air Quality Models, (USEPA, 1987b).

4.1 Modeling Methodology and Assumptions

This section outlines the approach used in the air dispersion modeling analysis. Model selection, meteorological data used, structure downwash considerations and model results for Compressor Station No. 20, St. Lucie County, Florida are discussed.

4.1.1 General Modeling Methodology

The air dispersion modeling approach follows USEPA and the FDER guidelines for determining compliance with State and National AAQSs and PSD. Air dispersion modeling was used to establish compliance with federal and/or state AAQS and to determine whether a PSD significant impact would occur.

The procedure listed below was followed:

- Model predictions for annual and short-term average concentrations based on net increases in NO_x and CO emissions for the project were performed using the Industrial Source Complex long-term (ISCLT2) and short-term (ISCST2) model (version 92062). A brief description of the Industrial Source Complex (ISC) model is given in Section 4.1.2.

- For preliminary PSD analysis and comparison to annual National AAQS for NO_x, the ISCLT2 was run using each of the latest five years of available meteorological data obtained from the Support Center for Regulatory Air Models (SCRAM) and processed into the Stability Array (STAR) format. The maximum off-site NO_x impact from all 5 years was then compared to the PSD/AAQS significance level. Since NO_x off-site impacts were greater than the 1 μg/m^3 significance level, additional modeling was performed for NO_x.

- An area of impact (AOI) was determined for NO_x using all 5 years of meteorological data. The distance to the most distant receptor having a significant annual impact (1 μg/m^3) for NO_x was determined and this defined the radius of the AOI.

- PSD increment consumption and a more detailed assessment of National AAQS compliance was performed for NO_x, since the maximum impact from the proposed facility sources exceeded the significant impact level (1 μg/m^3). The FDER was consulted and the appropriate PSD increment consuming and National AAQS adjacent source inventory was ordered.

- To determine PSD increment consumption for NO_x, the proposed project sources and all other emission sources identified by the FDER as increment consuming were modeled using the ISCLT2 model. The model was run using the 5 years of data previously discussed. The maximum off-site concentration from this analysis was compared to the PSD Class II increment for NO_x of 25 μg/m^3 to determine facility compliance.

- Additional modeling to demonstrate compliance with the NO_x National AAQS was conducted in a similar manner. However, all on-site and adjacent NO_x emitting sources were included. The results of this screening analysis indicated a potential exceedance of the NO_x National AAQS. Therefore, second level screening was performed using the Ozone (O_3) Limiting Method (Cole and Summerhays, 1979).

The use of the Ozone Limiting Method was approved by the FDER on April 7, 1993 (personal communication 1993). The Ozone Limiting Method involves an initial comparison of the estimated maximum NO_x concentration and the ambient O_3 concentration to determine which is the limiting factor to NO_2 formation.

i) If the ambient O_3 concentration is greater than the maximum NO_x concentration, total conversion of NO_x to NO_2 is assumed.

ii) If the maximum NO_x concentration is greater than the ambient O_3 concentration, the formation of NO_2 is limited by the ambient O_3 concentration. In this case, the NO_2 concentration is set equal to the ambient O_3 concentration plus a correction factor which accounts for in-stack and near stack thermal conversion.

In the Ozone Limiting Method the formation of NO_x is based objectively on the oxidizing potential of atmospheric O_3. For a more detailed description of the Ozone Limiting Method refer to Appendix G.

- A preconstruction monitoring exemption level analysis was conducted to determine if the proposed facility must conduct an air sampling program prior to construction and start up.

- Since the site is within 150 kilometers of a Class I area, modeling with ISCLT2 was conducted to determine the impact of the PSD increment consuming emissions at the nearest boundary of the Class I area.

- A Level I screening analysis using the USEPA model VISCREEN was used to determine impact on visibility due to the proposed project.

- For comparison to short-term AAQS for CO, the ISCST2 was run with five years (1985-1989) of meteorological data from the Support Center for Regulatory Air Models (SCRAM) Computer Bulletin Board. The maximum predicted off-site concentration was compared to the PSD significance level for CO for each averaging period of concern. Since all off-site receptors showed a concentration less than the significance level, no additional modeling analysis was conducted for CO.

4.1.2 Model Selection

The ISC dispersion model was used to evaluate emissions from the proposed facility. The ISC model was selected primarily for the following reasons:

- EPA and FDER have approved the general use of the model for air quality dispersion analysis because the model assumptions and methods are consistent with those in the Guideline on Air Quality Models (USEPA, 1987b);

- The ISC model is capable of predicting the impacts from stack, area, and volume sources that are spatially distributed over large areas and located in flat or gently rolling terrain; and

- The results from the ISC model are appropriate for addressing compliance with AAQS and PSD increments.

Major features of the ISC model are presented in Table 4-1. Concentrations due to point, area and volume sources are calculated by the model using the steady-state Gaussian plume equation for a continuous source.

4.1.3 Modeling Options

For modeling analyses that will undergo regulatory review, the following model options are recommended in the Guideline on Air Quality Models (USEPA, 1987b) and are referred to as the regulatory default options in the ISC model:

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

In this analysis, the USEPA regulatory default options were used to address maximum impacts.

4.1.4 Selection of Dispersion Coefficients

The ISC model has rural and urban options which affect the wind speed profile, 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 facility's surroundings (Auer, 1978). If the land use is classified as heavy industrial, light-moderate industrial, commercial, or compact residential for more than 50 percent of the area within a 3 kilometer radius around the proposed source, the urban option is selected. Otherwise, the rural option is used. Based on a review of the USGS topographical map of the land within a 3 kilometer radius around the facility, the rural mode was selected.

4.1.5 Meteorological Data

The USEPA Guideline on Air Quality Models (USEPA, 1987b) recommends the use of 5 years of representative meteorological data for use in air quality modeling. The most recent, readily available 5-year period is preferred. The meteorological data may be collected either on-site or at the nearest National Weather Service (NWS) station.

TABLE 4-1
Major Features of the ISC Model

ISC Model Features
• Polar or Cartesian coordinate systems for receptor locations
• Rural or urban option that affect windspeed profile exponent, dispersion rates, and mixing height calculations
• Plume rise as a result of momentum and buoyancy as a function of downwind distance for stack emissions (Briggs)
• Procedures suggested by Huber and Snyder (1976), Huber (1977), Schulman and Hanna (1986), and Schulman and Scire (1980) for evaluating building downwash and wake effects
• Procedures suggested by Briggs for evaluating stack-tip downwash
• Separation of multiple point sources
• Consideration of the effects of gravitational settling and dry deposition on ambient particulate concentrations
• Capability of simulating point, line, volume, and area sources
• Capability to calculate dry deposition
• Variation of windspeed with height (windspeed-profile exponent law)
• Concentration estimates for annual average
• Terrain-adjustment procedures for elevated terrain including a terrain truncation algorithm
• Receptors located above local terrain (i.e., "flagpole" receptors)
• Consideration of time-dependent exponential decay of pollutants
• The method of Pasquill (1976) to account for buoyancy-induced dispersion
• A regulatory default option to set various model options and parameters to EPA recommended values (see text for regulatory options used)
SOURCE: Users Guide for the Industrial Source Complex (ISC2) Dispersion Models Vol. 1 Draft. USEPA 450/4-92-008a.

The NWS station in West Palm Beach, Florida, located approximately 45 miles south of the site, is the nearest weather station that routinely records the hourly surface data required by air dispersion models. Because of the proximity of this NWS station to the site, the West Palm Beach meteorological data were considered representative of weather conditions occurring at the St. Lucie County Compressor Station.

Meteorological data used in the analysis were obtained from the FDER. The data consisted of a 5-year record of surface and upper air weather observations (1982-1986). Surface and upper air data were collected by the NWS at West Palm Beach. The data base consists of hourly surface data (i.e., windspeed, wind direction), and twice daily mixing heights. The surface and upper air data were preprocessed using the USEPA program RAMMET, which combines the surface and upper air data into a single file, which can then be input directly into the ISCST2 model. The 5 years of surface data from West Palm Beach were then processed using the USEPA STAR program, to generate the STAR files for use in the ISCLT2 model.

4.1.6 Source Data

The source parameters for Compressor Station No. 20 are given in Table 4-2. The location of the proposed stacks within the facility are presented on the plot plan in Appendix B. The emission point listed as 2005 on Table 4-2 corresponds to the new compressor engine. Emission point 2011 corresponds to the new emergency generator. Table 4-3 lists the emission rates modeled for NO_x and CO. The maximum pound-per-hour emission rates shown in the table were input to the ISCST2 model to determine concentrations for the short term averaging periods. Vendor supplied emission rates, in grams/bhp-hr, converted to tons per year emission rates, were used by the ISCLT2 model to determine annual average concentrations.

The full list of adjacent sources provided by the FDER is included in Appendix H. The "Screening Ratio Technique," approved by FDER was used to screen out some of the NO_x sources from the emissions inventory list. A memo discussing the application of the "Screening - Ratio Technique" and the refined adjacent source list are also included in Appendix H.

4.1.7 Receptor Grids Modeled

For ISCST2 and ISCLT2, the following receptor grids were modeled:

- A 100-meter spaced, 25 x 25 receptor grid array was used to determine the maximum off-site CO concentration.

TABLE 4-2

FGTC Phase III
Station No. 20
Summary of Source Parameters Used in the Modeling Analysis

	Stack Location (m)		Stack Dimensions		Operating Parameters	
Source Number	X (m)	Y (m)	Height (m)	Diameter (m)	Temperature (K)	Velocity (m/s)
2005	0	0	19.81	1.22	555.38	14.12
2011	36	150	6.71	0.15	873.16	78.73

TABLE 4-3

FGTC Phase III Expansion
Station No. 20
Modeled Emission Rates

SOURCE NO.	NO_x TONS/YR	CO MAX LB/HR
2005	77.26	26.46
2011	0.27	2.95
SOURCE NO.	**NO_x GM/SEC**	**CO MAX GM/SEC**
2005	2.22	3.33
2011	0.008	0.37

- A 100-meter spaced, 31 x 31 grid array was used to determine the maximum off-site NO_x concentration.
- A 100-meter spaced, 31 x 31 grid array was used to cover the AOI for NO_x adjacent source modeling.
- A 2-kilometer spaced, 31 x 31 grid array was used to determine NO_x concentrations for the Class I area (Everglades National Park).

These receptor grids were used, per guidance from FDER and the Guideline on Air Quality Models (USEPA, 1987b).

4.1.8 Building Wake Effects and GEP Considerations

Based on the dimensions of the structures located on the facility property, all stacks will be less than GEP height. Also, based on the location of emission points in relation to buildings and other solid structures, the stack emissions will be affected by wakes from some of the structures. Therefore, the potential for building downwash must be considered in the modeling analysis.

The procedure used for addressing the effects of building downwash are those recommended in the User's Guide for the Industrial Source Complex (ISC2) Dispersion Models (USEPA, 1992). In the ISC2 model, the building heights and widths are input in to the model for each direction. If the Huber-Snyder building downwash routine is used, the model picks the worst case dimension from all values. The effective width used by the program is the diameter of a circle with an area equal to the square of the width input to the model.

If a specific width is to be modeled, then the value input to the model must be calculated according to the following formula:

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

$$= 0.886 H_w$$

where: M_w = building width input to the model to produce a building width of H_w used in the dispersion calculation.

H_w = the actual building width for dispersion calculations.

If the Schulman-Scire wake effects method is used, the user inputs the building height and projected width associated with each wind sector. The actual inputs to the ISC2 model were generated using the Bowman Environmental Engineering Automated Downwash Program. The plant coordinates of all building corners, tier corners, tank centers and emission points are input into the Downwash Program. The program provides direction-specific building dimensions for either the ISC2 long- or short-term model, which are then directly input into the ISC2 source file. The program was run using a rectangular building wake area and an angle increment of 1 degree.

A summary of actual building dimensions for structures considered is presented in Table 4-4. Note that the warehouse, control building, paint storage, firehouse building, and pipeline building were not entered into the Bowman Program. Because of the buildings' low heights and positions with respect to the new stacks, they would have no influence on stack emissions.

4.2 Model Results

Initial modeling was performed for the net increase in emissions of the following pollutants emitted from the new compressor engine and the emergency generator to be installed at Compressor Station No. 20:

- NO_x, and
- CO.

These were the only pollutants modeled, since under PSD, only pollutants with a "Significant" increase in emissions resulting from major new or modified sources need to be considered. A summary of the maximum predicted off-site concentrations for each modeled pollutant, averaging period, National AAQS, and PSD/AAQS significance level is shown in Table 4-5. Table 4-6 presents the maximum off-site impact for NO_x and CO for each year modeled. The predicted maximum off-site impacts from each pollutant, due to the proposed changes at the facility were generally north and west of the property boundary.

Review of the maximum predicted off-site CO concentrations presented in Table 4-6 shows that all were below the PSD significance levels. The results of this air dispersion modeling indicate

TABLE 4-4

FGTC Phase III
Station No. 20
Building Dimensions

Building	Actual Building Dimensions		
	Height (ft)	Length (ft)	Width (ft)
Office/Auxiliary	21	135	25
Old Compressor Building	34	190	54
New Compressor Building	41	72	60
Warehouse	15	105	30
Control Building	10	15	10
Paint Storage	11	20	20
Fire House Building	12	40	15
Pipeline Building	15	60	30

Note: Only the Office/Auxiliary building, Old Compressor and New Compressor buildings were entered into the GEP model. The other structures do not affect stack emissions.

TABLE 4-5

FGTC PHASE III
STATION NO. 20
MODELING RESULTS
MAXIMUM PREDICTED AVERAGE CONCENTRATION OF MODELED POLLUTANTS AND COMPARISON TO SIGNIFICANT IMPACT LEVEL

	AVG TIME	MAX OFFSITE ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)	SIGNIFICANT IMPACT ($\mu g/m^3$)
NO_x				
SOURCES 2005 and 2011	Annual	1.84	100	1
CO				
SOURCES 2005 and 2011	1-hour	113	40,000	2,000
	8-hour	58	10,000	500

Notes: Annual maximums are from 5 separate model runs (1985-1989) STAR met data,
Short term maximums are from five runs with 1985-1989 met data.

TABLE 4-6

FGTC Phase III Project
Station No. 20
Maximum Modeled Off-Site Impact

Pollutant	Averaging Period	1985	1986	1987	1988	1989
NO_x	Annual	1.72	1.17	1.74	1.49	1.84
CO	1-hour	113	113	108	112	113
	8-hour	58	51	58	52	48

NOTE: All values in $\mu g/m^3$ unless otherwise noted.

that the proposed increase in CO emissions from Compressor Station No. 20 should not have an adverse effect on the surrounding area.

The proposed project's NO_x and CO maximum predicted off-site concentrations are below the preconstruction monitoring levels. The NO_x concentration is less than the preconstruction monitoring level of 14 $\mu g/m^3$ (1.84 $\mu g/m^3$) and CO 8-hour average concentration is less than the preconstruction monitoring level of 575 $\mu g/m^3$ (58 $\mu g/m^3$). Since both CO and NO_x are below the preconstruction monitoring level, there will not be a need to monitor prior to construction.

The analysis of the proposed project's NO_x emissions found the maximum exceeded the PSD significance level (1.84 $\mu g/m^3$ versus 1.0 $\mu g/m^3$). Therefore, two additional analyses are required as discussed in Section 4.1.1.

For PSD increment consumption, the proposed project sources, and adjacent increment consuming sources identified by the state were processed using the ISCLT model. Table 4-7 presents the results of this effort. As shown by the table, the maximum increment consumed is 2.31 $\mu g/m^3$ compared to PSD Class II limit of 25 $\mu g/m^3$. Therefore, the proposed project is in compliance with PSD regulations.

The second additional analysis required a demonstration of compliance with the National AAQS. This analysis was similar to that performed for increment consumption but included all on- and off-site sources, not just those which consume PSD increment. Table 4-8 presents a summary of the National AAQS compliance review.

The maximum off-site annual average NOx concentration was predicted to be 287 $\mu g/m^3$ (Table 4-8). Therefore, the Ozone Limiting Method, which is a second-level screening technique discussed in Section 6.2.3 of the USEPA Guideline on Air Quality Models (USEPA 1987b), was used to refine the estimate of project impact.

An annual average ozone concentration of 1.15 ppm (24.4 $\mu g/m^3$) for St. Lucie County was provided by FDER. This data was combined with the results from the ISCLT2 model, as input to the Ozone Limiting Method described in Appendix G. The resulting maximum predicted NO_2 concentrations are listed in the last column of Table 4-8. The maximum off-site NO_2 concentration, including the addition of the background NO_x concentration, was 74.1 $\mu g/m^3$.

This result indicates that the maximum post project NO_2 concentration will not exceed the National AAQS limit of 100 $\mu g/m^3$.

TABLE 4-7

FGTC Phase III Project
Station No. 20
PSD Adjacent Sources
Maximum Modeled Off-Site Impact
for PSD Increment Analysis

Pollutant	Averaging Period	1985	1986	1987	1988	1989
NO_x	Annual	2.18	1.73	2.19	1.94	2.31

NOTE: All values in $\mu g/m^3$ unless otherwise noted.
NO_x Class II PSD Increment equals $25 \mu g/m^3$.

TABLE 4-8

FGTC Phase III Project
Station 20
Ozone Limiting Results
($\mu g/m^3$)

Year	Maximum NO_x Impact	Thermal NO_x[a]	Background Annual Average Ozone Concentration	NO_2 Impact[b]	Background Annual Average NO_x	Total NO_2 Impact
1985	286.5	28.7	24.4	53.1	21	74.1
1986	254.7	25.5	24.4	49.9	21	70.9
1987	282.1	28.2	24.4	52.6	21	73.6
1988	284.8	28.5	24.4	52.9	21	73.9
1989	286.1	28.6	24.4	53.0	21	74.0

a Thermal NO_x = 0.1 [NO_x]
b [NO_2] = 0.1 [NO_x] + [O_3]
Note: [ ] denotes concentrations

Since the site is within 150 kilometers of the Everglades National Park, additional analysis was required for Visibility and Class I increment. A visual effects screening model (VISCREEN) showed that impacts on visibility from the facility would not exceed the criteria inside or outside the closest Class I area (Everglades National Park). The maximum predicted plume contrast against both sky (0.000) and terrain (0.00) is well below the Class I criteria for visibility (0.05). The delta E color difference parameter for sky (0.002) and terrain (0.00) is much less than the 2.00 criteria. The results of the visibility analysis are included in Appendix F.

A floppy diskette containing all model input and output files, and structure downwash program input and output is included in Appendix F. Area concentration maps, showing the facility boundary and maximum impacts for NO_x and CO at each modeled receptor, are included in Appendix F for the worst case year.

5.0 SOILS, VEGETATION, VISIBILITY AND ASSOCIATED POPULATION GROWTH IMPACTS

PSD regulations require proposed actions be reviewed for potential effects to soils, vegetation, visibility and that they be evaluated for possible secondary air quality impacts associated with population growth induced by the project. This section reviews these issues for the proposed expansion of Compressor Station No. 20.

5.1 Impacts Upon Soils and Vegetation

The USEPA has suggested screening level concentrations for determining the potential for impacts to vegetation impacts from exposure to NO_x, SO_2 and CO. Since NO_x is the only pollutant which will be emitted in significant quantities, it will be the only pollutant reviewed for impacts to vegetation.

The USEPA screening threshold is 94 $\mu g/m^3$ for NO_x on an annual basis. Maximum project impact for NO_x is predicted to be 1.84 $\mu g/m^3$, therefore no impact to vegetation is likely and no additional investigation warranted.

The amounts of nitrogen and/or sulfur which could be deposited on local soils by the project are minimal. Therefore, although not quantified, the impacts are not expected to be measurable.

5.2 Impacts Upon Visibility

Analysis of impacts to visibility, as required under PSD regulations is directed toward preserving the "integral vista" of Class I areas. In Florida, this analysis is restricted to those sources within 150 kilometers of a Class I area due to the limited ability of current models to accurately define impacts for areas outside this zone.

The only Class I area within 150 km of Compressor Station No. 20 is The Everglades National Park, 135 kilometers south. Based on the results of the USEPA VISCREEN model as presented in Section 4.2, no adverse impact is expected.

5.3 Impacts Due to Associated Population Growth

There will be a small increase in the number of temporary construction workers during the construction of the additional facilities at Compressor Station No. 20. However, there will be no increase in the permanent regional work force. As a result there will be no permanent impacts on air quality due to associated population growth.

6.0 BEST AVAILABLE CONTROL TECHNOLOGY EVALUATION

The prime movers in the natural gas industry are generally heavy duty, natural gas-fired, stationary IC engines. These engines are applied to power compressors used for pipeline transmission, field collection of gas from wells, underground storage, and gas processing plant activities. Stationary IC engines used include both gas turbines and reciprocating engines.

The use of reciprocating engines has been widespread at natural gas pipeline compressor stations. A recent Gas Research Institute research study (GRI, 1990) reports that the number of reciprocating engines is five times that of gas turbines. The advantages of reciprocating engines are primarily their fuel efficiency and their capability to operate reliably at variable loads to meet the fluctuating pipeline conditions. Since Compressor Station No. 20 is an existing compressor station with significant load fluctuations, a reciprocating engine will be installed.

FGTC selected the use of a reciprocating engine instead of a gas turbine for the following reasons:

- Gas turbines do not respond as quickly and efficiently to load changes. Wide fluctuations in gas demand are likely to occur along the pipeline at the location of Compressor Station No. 20.

- Compressor Station No. 20 is an existing station with 4 reciprocating engines operating on site. The mechanical operation of a reciprocating engine generates a pulse vibration which can adversely affect the operation of a gas turbine.

The total potential emissions of NO_x from the proposed new engine are 77.26 TPY, exceeding the PSD significant emission rate of 40 TPY. Therefore, a BACT analysis for NO_x must be performed, including identification of control technologies for reciprocating engines; a review of environmental, energy and economic impacts associated with technically feasible control options; and a BACT analysis summary.

6.1 The BACT Process

The structure of the BACT analysis is shown in Figure 6-1. This approach reflects the most recent "top-down" BACT guidance (USEPA, 1990a) by USEPA for PSD permit determinations as described in Section 3.1.2.2 of this report application.

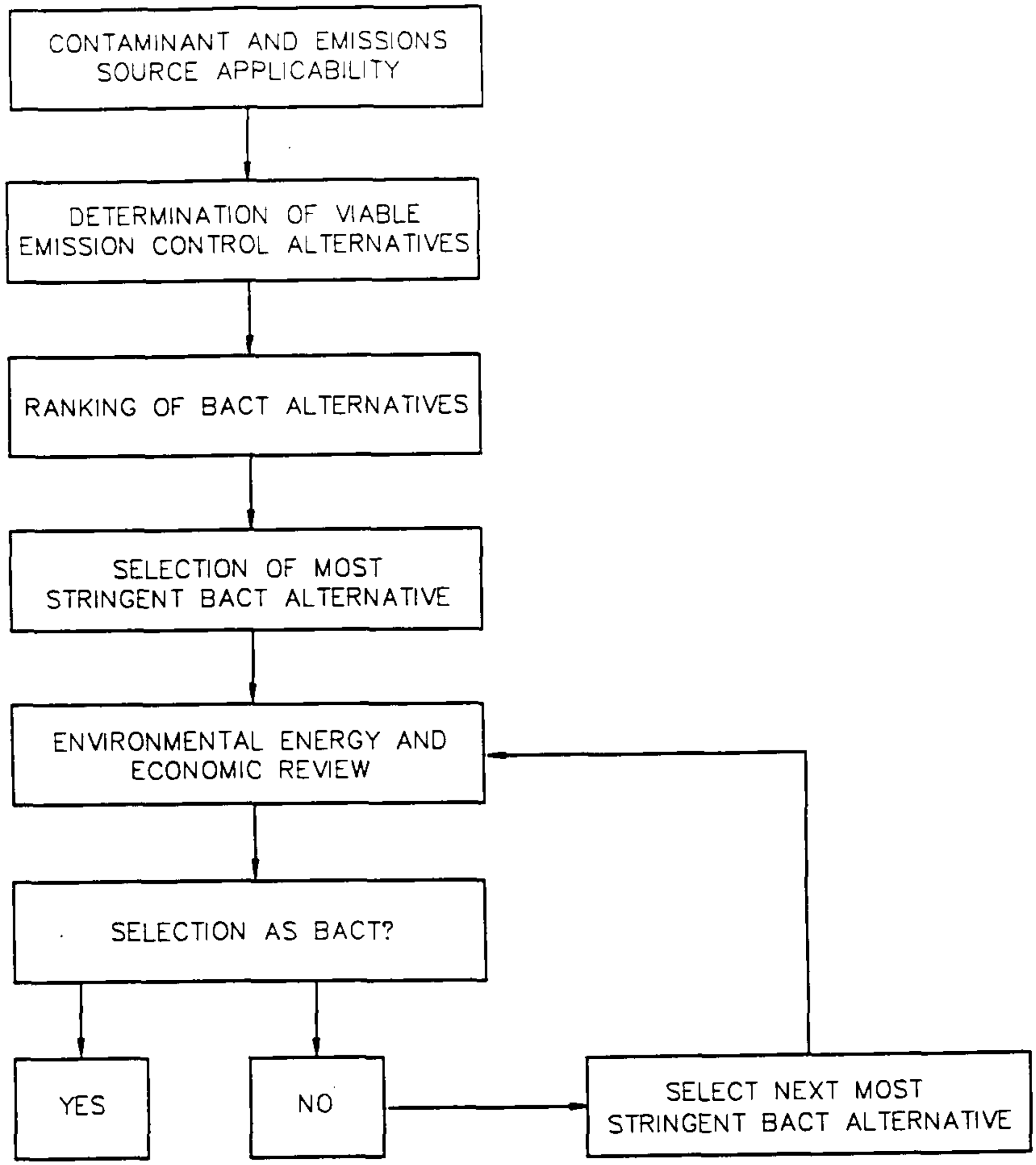

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FIGURE 6-1
"TOP DOWN" BACT
DECISION-MAKING PROCESS
FLORIDA GAS TRANSMISSION COMPANY
FLORIDA

DRAWN:	SH	DATE:	01-19-93	PROJECT NUMBER:	
APPV'D:		REVISED:		6792-068	

CF.679257

No technically feasible alternative should be ruled out when emission control technologies are selected for evaluation as BACT. The review should be broad enough to consider controls applied to similar source categories as well as innovative control technology where energy, environmental, or economic impacts so warrant.

The environmental analysis should estimate the net impact associated with each control alternative. Both beneficial, as well as, adverse impacts should be discussed and, where possible, quantified. When environmental impacts are weighed, the analysis should consider all pollutants affected by the control alternative. This includes pollutants that are not currently regulated under the CAA (such as air toxics), but may cause significant environmental impacts. In addition, the environmental analysis should consider appropriate non-air effects, such as water pollution or solid/hazardous waste impacts.

The energy impact analysis should estimate the direct energy effects of the control alternatives in units of energy consumption (Btu's, kwh, barrels of oil, tons of coal, etc.). Where possible, the energy requirements of the control options should be shown in terms of total and incremental (units of energy per ton of reduction) energy costs.

The economic analysis involves assessing the costs associated with installation and operation of the various BACT alternatives. Examples of costs to be included are:

- capital and interest charges,
- engineering and installation costs,
- operating and maintenance labor and materials costs,
- energy costs,
- water disposal costs, and
- lost revenue due to equipment downtime.

Credit for tax incentives should also be included along with credits for product recovery costs and by-product sales generated from the use of control systems.

This review follows the standard approach for BACT economic evaluations that determines annual control cost per unit of pollution removed. The total annual operating cost, in dollars, for alternative controls are divided by the total emission reductions in tons, to produce easily compared dollars per ton ratios. Incremental cost ratios (in dollars per ton) of one control method over another are also calculated for comparison based on incremental annual cost and incremental emissions reductions approved for BACT economic evaluations. Additional details of this cost estimating procedure are contained in Appendix I.

6.2 NO_x Control Review

This section provides the NO_x BACT assessment for the proposed engine to be installed at Compressor Station No. 20.

6.2.1 Applicable NSPS

The minimum control requirements of BACT are those imposed by NSPS. For IC engines an NSPS has been promulgated only for stationary gas turbines (40 CFR Part 60, Subpart GG). A comparable standard for reciprocating engines has not been issued. Therefore, NSPS regulations do not provide any guidance in establishing BACT.

6.2.2 Previous BACT Limits

Another important consideration in reviewing potential BACT emission limits is past BACT determinations for similar sources. The USEPA BACT/LAER Clearinghouse (USEPA, 1987-1992) contains extensive data on past BACT regulatory determinations for reciprocating engines in natural gas compressor service. Table 6-1 summarizes BACT determinations issued since 1987 for NO_x emissions from gas-fired stationary reciprocating engines. The information was obtained from BACT/LAER Clearinghouse documents from 1987 to 1992, as well as from actual permit applications, permits issued, and conversations with personnel of air permitting agencies from various states. Information from the BLIS Bulletin Board System was obtained using the following standard query: Process Code Number = 15.004 (Natural Gas Internal Combustion), Process Name = Engine, and Pollutant = NO_x. All reciprocating engines, which include natural gas compressor stations and power/cogeneration and other uses identified in the BACT/LAER Clearinghouse are listed in a table in Appendix I.

6.2.3 Identification of NO_x Control Technologies for Reciprocating Engines

This section evaluates the control technologies capable of reducing NO_x emissions produced by reciprocating engines relative to their potential application as BACT for the proposed 4,000-bhp reciprocating engine. This BACT analysis follows USEPA's most recent draft guideline for the top-down approach (USEPA, 1990a).

All potentially applicable control technologies for reciprocating engines are reviewed. The technologies can be separated into two major groups:

- Reducing NO_x emissions by modification of the conventional reciprocating engine with "low-NO_x" engine design, and

TABLE 6–1
Summary of BACT Determinations for NOx Emissions from Natural Gas–Fired Reciprocating Pipeline Compresor Engines

Company Name	State	Permit Number	Date of Permit	Total Capacity (Bhp)	Engine Specifications: Fuel Type	Make	Model	Size (Bhp)	NOx Emission Limit* (g/Bhp–hr)	(lb/hr)	(tpy)	Control Method
Southern Natural Gas Co.	AL	406–0003–X002	19–Feb–88	4,160	N.G.			4,160	2.2			Clean Burn Engine
Florida Gas Transmission Company	AL	503–3028–X001	22–Feb–91	2,400	N.G	Cooper	GMVR–12C	2,400	2.0			Lean Combustion
Southern Natural Gas Company	AL	406–0003–X	19–Feb–88	4,160	N.G.	Dresser–Rand	TCVD–10	4,160	2.2	20.2		Lean Burn Engine(1)
Mohave Pipeline Operating Co.	AZ	1231	12–Jun–91	17,500	N.G			17,500			491 7	Fuel Usage
Mohave Pipeline Operating Co.	AZ	1231	12–Jun–91	13,800	N.G			13,800			347.8	Fuel Usage
Florida Gas Transmission Company	FL	FL–160	09–May–91	4,000	N G	Cooper	GW–330C2	4,000	2.0			Lean Burn Engine
Florida Gas Transmission Company	FL	FL–161	10–May–91	2,400	N.G	Dresser–Rand	412–KVSR	2,400	2 0			Lean Burn Engine
Northern Natural Gas Company	IA	PROJECT–89–117	05–Sep–90	8,000	N.G.	Cooper		4,000	1.8			Lean Burn Engine
Northern Natural Gas Company	IA	PROJECT–89–117	05–Sep–90	8,000	N G.	Cooper		2,000	1.8			Lean Burn Engine
Northern Natural Gas Company	IA	PROJECT–89–117	05–Sep–90	8,000	N G.	Cooper		2,000	1.8			Lean Burn Engine
Natural Gas Pipeline Company	IL	85100014	01–Mar–89	1,600	N.G	Worthington	MLV–10	4,000	9.0	79 4		Design & Oper.Pract.
Florida Gas Transmission Company	LA	PSD–LA–567	17–Apr–91	2,400	N.G.	Cooper	GMWC–8C	2,400	3.5			Lean Burn Engine
Florida Gas Transmission Company	MS	2200–00008	14–May–91	2,400	N.G	Dresser–Rand	412–KVSR	2,400	2.0			Lean Combustion
Meridian Oil Gathering, Inc	NM	PSD–NM–742–M–2	11–Oct–90	21,200	N.G.	White Super.	8SGTB	2,650	1.5			Clean Burn
NGPL	OK	90–075–C	01–Nov–90	2,400	N.G.			2,400	2.5			Lean Burn Combustion
NGPL	OK	90–075–C	01–Nov–90	1,600	N.G.			1,600	2.5			Lean Burn Combustion
Consolidated Gas Pipeline Corp.	PA	59–399–008	10–May–88	8,400	N.G.	Dresser–Rand	TCV–10	4,200	3.0	27.8		Lean Burn Engine (2)
National Fuel Gas Supply Corp.	PA	53–329–001	13–Jun–89	6,000	N.G.	Cooper	8015JHC2	3,000	2.0	13 2		Lean Burn Engine
National Fuel Gas Supply Corp	PA	53–329–022	01–Oct–90	2,600	N.G.	Waukesha	12V–AT25GL	2,600	2.0	6 6		Clean Burn Tech.
CNG Transmission Corporation	PA	18–329–001	24–Sep–91	4,200	N.G	Superior	12–SGTB	4,200	2.0	6 6		Clean Burn Tech
CNG Transmission Corporation	PA	04–329–001	13–Mar–92	3,200	N.G.			3,200	2.0	3.4		Clean Burn Tech
ANR Production Company	VA	11064	03–Mar–88	1,800	N.G.	Caterpillar	G398TAA	600	1.2	1.6		Catalytic Convertor

(1) Per Stack Test
(2) Air to Fuel Ratio = 4.5 to 1
* For a single engine
** pound per day
N.G = Natural Gas

- Converting NO_x in the exhaust gas from the reciprocating engine by add-on catalytic exhaust gas treatment devices.

The discussion of each potential NO_x control technology includes a description of the technology and the potential NO_x emission reduction, if the technology is concluded to be technically feasible.

6.2.4 Technologies Involving Engine Modification

The concept of low-NO_x reciprocating engines is described in the NSPS Background Information Document (BID) for reciprocating engines issued by USEPA in July 1979 (USEPA, 1979). Five types of engine or process modifications have been recognized by USEPA as technically viable for reducing NO_x emissions from stationary reciprocating engines:

- Steam/Water injection,
- Air-to-fuel ratio changes,
- Retarded ignition timing,
- Derating power output, and
- Exhaust gas recirculation.

Each method is discussed in the following sections.

6.2.4.1 Steam/Water Injection

The concept of designing a low-NO_x reciprocating engine focuses on controlling the combustion temperature, because thermal NO_x formation generally increases as combustion temperature increases. Favorable conditions for thermal oxidation of molecular nitrogen can be reduced by quenching the flame temperature with low quality steam or water. In this method, steam or water is injected at a location downstream from the combustion zone inside each firing cylinder.

Steam or water injection to reduce NO_x formation does not work well at the high water injection rate required for reciprocating engines. Experiments with large-bore, reciprocating engines have concluded that steam/water injection for controlling NO_x emissions can cause irreversible structural damage to the engine block (USEPA, 1979). Thus, steam or water injection technology for reciprocating engines is considered technically infeasible. Therefore, this method will not be discussed further.

6.2.4.2 Air-to-Fuel Ratio Changes

The state-of-the-art concept in designing a low-NO_x reciprocating engine involves raising the air-to-fuel ratio to create a lean fuel mixture for the combustion process. The peak combustion temperature is lowered due to a lower heat of combustion from burning less fuel, and by the high excess air level, which tends to dilute the combustion gases. Cooper-Bessemer was the first manufacturer of reciprocating engines to incorporate this concept, which it called CleanBurn® technology, into the design of new engines.

In general, the high air-to-fuel ratio design is referred to as lean-burn technology for gas-fired reciprocating engines. The name is derived from the lean mixture of air-to-fuel in the main combustion cylinder. The air-to-fuel ratio can reach as high as 200 for some engine designs and operating conditions, according to one of the major reciprocating engine suppliers (Dresser-Rand, 1990).

The lean-burn design requires increasing the stoichiometric air-to-fuel ratio above the design ratio for a conventional reciprocating rich-burn engine. In general, small increases in the air-to-fuel ratio (approximately 10%) cause a significant reduction in NO_x (approximately 30%) with less than a 5% fuel penalty (USEPA, 1979). On turbocharged engines, this NO_x reduction using lean-burn technology can be achieved by operating at high manifold pressures, which results in lower combustion temperatures and reduces NO_x formation; however, misfiring and erratic combustion can occur at very lean mixtures. The limits to which the air-to-fuel ratio can be increased are related to three major engine design factors:

- The capability of the turbocharger to produce higher air manifold pressures for rated engine loading,

- The ability of the ignition system to light-off the leaner mixtures, and

- The combustion chamber characteristics which must maintain efficient combustion with leaner mixtures.

With the current state-of-the-art engine and turbocharger designs coupled with advanced control technology, all of these factors can be achieved.

Lean-burn, natural gas-fired reciprocating engines are capable of achieving NO_x emission levels as low as 2.0 grams/bhp-hr, depending on size of the engine, manufacturer, type of fuel, etc. NO_x emissions from current generation uncontrolled rich-burn or first generation lean-burn reciprocating engines are equal to 11 grams/bhp-hr as presented in AP-42, Section 3.2 (USEPA, 1988). Thus, the state-of-the-art, lean-burn engine results in a NO_x decrease of 82%.

6.2.4.3 Retarded Ignition Timing

Retarding the spark ignition timing of the reciprocating engine reduces the peak combustion pressure and temperature, thereby lowering thermal NO_x formation. The timing delay is measured by degrees in reference to the engine's crankshaft rotation. The greatest benefit from this method is realized with small (2 to 6°) changes in timing. After about 6° timing retard, the amount of NO_x reduction per degree diminishes while fuel consumption rises rapidly (USEPA, 1979).

A study for the American Gas Association showed that the NO_x emissions from 10 different gas-fired, naturally aspirated engine models ranged from a 7% reduction to a 2% increase per degree of ignition retardation (Urban and Springer, 1975). USEPA's research (USEPA, 1979) reported that NO_x reductions (per degree of retard) ranged from 0.6% to 8.5% for turbocharged engines. Overall, the USEPA's report concluded that retarding ignition timing reduced NO_x emissions 15% for uncontrolled gas-fired engines.

Based on an uncontrolled emission rate of 11.0 grams/bhp-hr, as specified in USEPA's AP-42, retarding the ignition could conceivably result in an emission rate as low as 9.35 grams/bhp-hr. However, this is more than 4.5 times higher than for the engine proposed for installation at Compressor Station No. 20.

This method is not applicable to the new generation of lean-burn engines, as control of ignition timing has already been incorporated in the design of the units. Further adjustments could actually increase NO_x emissions which runs counter to the indicated objective. Therefore, this method will not be reviewed further.

6.2.4.4 Derating Power Output

A reciprocating engine can be derated by operating at less than its full rated horsepower. The effect of derating on an engine is to reduce peak combustion cylinder temperatures and pressures, thus lowering NO_x formation rates.

Reported NO_x reduction levels achieved by derating an engine vary greatly for different reciprocating engines. Data compiled by USEPA (USEPA, 1979) show that non-turbocharged engines achieve the largest reduction because derating has a greater effect on air-to-fuel ratios for these units. In contrast, turbocharged engines operate at a more constant air-to-fuel ratio and, therefore, very little NO_x reduction is achieved by derating. Normalized NO_x reduction from derating (i.e., percent of NO_x reduction per percent derate) is reported from 0.25% to 6.2% for normally aspirated or blower-charged engines, and 0.01% to 2.6% for turbocharged engines. The USEPA report showed that NO_x reduction ranged from a 10% increase to a 90% reduction, and averaged approximately a 35% reduction at a derating of 25% of rated torque for all engines as a group. Naturally aspirated engines are affected to a greater degree, as derating has a more significant fuel leaning effect on this engine type. Turbocharged engines are affected to a lesser degree as changes to air-to-fuel ratio are less.

While it is true that an emission reduction can be achieved by this method, the horsepower produced by the engine is also reduced. The 4,000 horsepower required for Compressor Station No. 20 was determined by FGTC's System Planning Department as needed to meet the projected gas volume demand based on FGTC gas contracts. Therefore, lowering the required horsepower of the proposed engine would decrease the volume of gas transmitted through the station and ultimately jeopardize FGTC's ability to fulfill gas contracts. If this method were employed at Compressor Station No. 20, a larger compressor engine would be required to compensate for the power derate. The net effect of installing a larger engine (5,400 bhp) and derating by 25% for NO_x control is a 20% decrease in NO_x emissions (0.8% NO_x reduction per percent derate).

6.2.4.5 Exhaust Gas Recirculation

Exhaust gas recirculation (EGR) reduces peak combustion temperatures in a reciprocating engine by replacing a fraction of the combustion air with exhaust gases. The recirculated exhaust gases serve to absorb heat without providing significant additional oxygen for the conversion of nitrogen to NO_x.

EGR can be accomplished by either introducing exhaust gases into the intake manifold or restricting the exit of gases from the cylinder by internal recirculation. Externally recirculated gases must be cooled before they are reintroduced into the combustion cylinder to provide greater heat absorption per charge.

EGR is most effective in reducing NO_x emission from conventional, rich-burn reciprocating engines because its application can increase the air-to-fuel ratio. USEPA's research (1979) reported a NO_x reduction of 34% for a gas-fired blower-charged engine with 6% EGR rate. Excessive EGR rates can result in increased fuel consumption, high CO emissions, and engine misfire (GRI, 1990).

EGR is not effective for a lean-burn engine with a high air intake flow rate, since EGR cannot further dilute the air/fuel mixture to any appreciable degree. In addition, no system has been developed for the complex control needed to regulate the recirculation of the exhaust gases.

Based on the NO_x emission rate from an uncontrolled rich-burn engine of 11.0 grams/bhp-hr, and 34% reduction due to EGR, EGR is capable of achieving a NO_x emission rate of 7.3 grams/bhp-hr. Because EGR does not apply to the current generation of lean-burn engines, and because the emission rate EGR would produce for a rich-burn engine is greater than that proposed, EGR will not be reviewed further.

6.2.5 Technologies Involving Exhaust Gas Treatment

Review of the literature on control technologies has identified four post-combustion control options for reducing NO_x emissions. These options include:

- NO_xOUT Process
- Thermal DeNO_x
- Nonselective Catalytic Reduction
- Selective Catalytic Reduction

Each of these control methods and their applicability to the proposed project are reviewed below.

6.2.5.1 NO_xOUT Process

The NO_xOUT process originated from the initial research by the Electric Power Research Institute (EPRI) in 1976 on the use of urea to reduce NO_x. EPRI licensed the proprietary process to Fuel Tech, Inc., for commercialization. In the NO_xOUT process, aqueous urea is injected into the flue gas stream ideally within a temperature range of 1,600°F to 1,900°F (Fuel Tech, 1990). In the presence of oxygen, the following reaction occurs:

$$CO(NH_2)_2 + 2NO + 1/2\ 0_2 \rightarrow 2N_2 + CO_2 + 2H_2O$$

The amount of urea required is most cost effective when the treatment rate is 0.5 to 2 moles of urea per mole of NO_x. In addition to the original EPRI urea patents, Fuel Tech claims to have a number of proprietary catalysts capable of expanding the effective temperature range of the reaction to between 1,000°F and 1,950°F (Lin, Diep and Dubin, 1991). Advantages of the system are:

- Low capital and operating costs due to utilization of urea injection, and

- The proprietary catalysts used are nontoxic and nonhazardous, thus eliminating potential disposal problems.

Disadvantages of the system are:

- Formation of ammonia from excess urea treatment rates and/or improper use of reagent catalysts, and
- SO_3, if present, will react with ammonia created from the urea to form ammonium bisulfate, potentially plugging the cold end equipment downstream.

Commercial application of the NO_xOUT system is limited to three reported cases:

- Trial demonstration on a 62.5-ton-per-hour (TPH) stoker-fired wood waste boiler with 60 to 65% NO_x reduction,
- A 600-million-British-thermal-unit (MMBtu) CO boiler with 60 to 70% NO_x reduction, and
- A 75-megawatt (MW) pulverized coal-fired unit with 65% NO_x reduction.

The NO_xOUT system has not been demonstrated on any stationary IC engine.

The NO_xOUT process is not technically feasible for the proposed lean-burn engine. The exhaust gas temperature of a lean-burn engine is typically between 495°F and 550°F, well below the temperature rate of 1,000°F to 1950°F required for the NO_xOUT process to work effectively. Raising the exhaust temperature several hundred degrees would require installation of an exhaust gas heater. The heater installation would be economically prohibitive and would result in increases in fuel consumption, the volume of gases that must be treated by the control system, and increased air emissions, including NO_x. Therefore, this analysis does not consider the NO_xOUT process.

6.2.5.2 Thermal DeNO$_x$

Thermal DeNO$_x$ is Exxon Research and Engineering Company's (Exxon, 1986, 1987) patented process for NO_x reduction. The process is a high temperature selective noncatalytic reduction (SNCR) of NO_x using ammonia as the reducing agent. Thermal DeNO$_x$ requires the exhaust gas temperature to be above 1,800°F. However, use of ammonia plus hydrogen lowers the temperature requirement to about 1,000°F. For some applications, the required temperature must be achieved by additional firing in the exhaust stream prior to ammonia injection.

The only known commercial applications of Thermal $DeNO_x$ are on heavy industrial boilers, large furnaces, and incinerators with exhaust gas temperatures above 1,800°F. There are no known Thermal $DeNO_x$ applications in the reciprocating engine industry. Temperatures of 1,800°F require alloy construction materials with very large piping and components since the exhaust gas volume is increased by several times. As with the NO_xOUT process, high capital, operating, and maintenance costs are expected due to construction material specifications, additional duct burner systems, and increased fuel consumption. Burning additional fuel would increase emissions.

The exhaust gas temperature of a lean-burn engine is typically between 495°F to 550°F thus, the Thermal $DeNO_x$ process is technically infeasible because the reciprocating engines exhaust gas temperature is below the optimal temperature range of 1,000 to 1,800°F, and the cost to raise the exhaust gas to such a high temperature would be prohibitively expensive.

6.2.5.3 Nonselective Catalytic Reduction

A non-selective catalytic reduction system (NSCR), is commercially available for NO_x control on reciprocating engines. The NSCR process requires a low oxygen content in the exhaust gas stream and high temperature (700°F to 1,400°F) to be effective. Because rich-burn engines typically achieve low oxygen levels of less than 4% and the required (GRI, 1990) temperature, they can use the NSCR process. Lean-burn engines typically have a high air-to-fuel ratio (exhaust gas oxygen content of 12 to 15%), and an exhaust gas temperature of 515°F. As a result, NSCR is not a technically feasible add-on NO_x control device for FGTC's proposed lean-burn engine. Therefore, the combination of a lean-burn engine and NSCR was not considered further in the BACT analysis.

6.2.5.4 Lean-Burn Engine with Selective Catalytic Reduction (SCR)

A NO_x abatement technology for oil- and gas-fired combustion sources currently receiving considerable attention is the selective catalytic reduction (SCR) process with ammonia injection. The technology has been well developed and applied in Japan, especially for control of emissions from gas-, oil-, and coal-fired utility boilers. SCR has been applied domestically on combustion sources which generate large quantities of NO_x, such as utility and industrial boilers and electric power generating gas turbines.

SCR catalysts consist of two types: metal oxides and zeolite. The base metal catalysts are either vanadium or titanium embedded into a ceramic matrix structure; the zeolite catalysts are ceramic molecular sieves extruded into modules of honeycomb shape. The all-ceramic zeolite catalysts are durable, and less susceptible to catalyst masking or poisoning than the noble metal/ceramic base catalysts (Byrne, Chen and Speronello, 1991). All catalysts exhibit advantages and disadvantages in terms of exhaust gas temperatures, ammonia/NO_x ratio, and optimum exhaust gas oxygen concentrations. A common disadvantage for all catalyst systems is the narrow window of temperature between 600° F and 900° F within which the NO_x reduction process takes place (Schorr, 1989; Steuler, 1990a, 1990b; Engelhard, 1990a,b,c; Johnson-Matthey, 1990). Operating outside this temperature range results in catastrophic harm to the catalyst system. Chemical poisoning can occur at lower temperature conditions, while thermal degradation occurs at higher temperatures. Reactivity can be restored only through catalyst replacement.

Catalysts are subject to loss of activity over time. Since the catalyst is the most costly component of the SCR system, applications require servicing and cleaning the catalyst's surface every 2,000 to 3,000 hours of operation. The cleaning normally consists of blowing the catalyst surfaces with a compressed air gun or water jet. Most catalyst suppliers guarantee a catalyst life of 3 years, assuming certain operating conditions.

Technically, SCR is potentially applicable to further reduce the already low NO_x emissions (2 grams/bhp-hr) from the proposed lean-burn reciprocating engine. SCR is capable of achieving NO_x reduction of 70 to 90%. For the proposed lean-burn engine, with already low NO_x concentration in the exhaust gases, a removal rate of 80% is the maximum which can be expected. This would result in NO_x emissions of 0.4 grams/bhp-hr, which represents an overall 96% NO_x reduction compared to an uncontrolled rich-burn engine (at 11.0 grams/bhp-hr).

6.2.5.5 Combination of Rich-Burn Engine and NSCR

Although the March 15, 1990, draft top-down BACT guideline document does not require inherently higher emitting processes than the proposed process be evaluated, this BACT analysis also considered the option of using rich-burn engines coupled with NSCR.

Rich-burn reciprocating engines are defined as those which contain less than 4% oxygen concentration in the exhaust gas. Typically, rich-burn engines are naturally aspirated engines with near stoichiometric air-to-fuel ratios and produce exhaust gas temperatures in the range of 1,200° F to 1,300° F.

NSCR technology uses a precious metal to catalyze the reactions of NO_x with CO and unburned hydrocarbon fuel in the exhaust gas streams to form nitrogen, carbon dioxide, and water vapor. A complete NSCR system includes an exhaust gas oxygen sensor, an exhaust gas monitor, a hydrocarbon fuel injector, an automatic air/fuel controller, and a temperature sensor for automatic shutdown of the engine if overheating occurs. The engine exhaust entering the catalyst bed is maintained slightly fuel-rich to maximize NO_x reduction. The hydrocarbon fuel injector automatically controls an adjustable valve that supplies a small amount of hydrocarbon fuel to compensate for the changes in engine load or ambient conditions.

Technically, NSCR is potentially applicable to reduce 90% of the NO_x emissions in the exhaust gas of the rich-burn reciprocating engine (Exxon, 1987). Using 11 gram/bhp-hr as the uncontrolled NO_x emission rate for a rich-burn engine, a NO_x removal efficiency of 90% will result in a NO_x emission level of 1.1 gram/bhp-hr (i.e., 10% of the uncontrolled rich-burn engine NO_x emission rate of 11.0 gram/bhp-hr).

6.2.5.6 Summary of Technically Feasible NO_x Control Methods

There are two basic alternatives for reduction of NO_x emissions from reciprocating engines: engine modification and add-on control technology. Table 6-2 summarizes the technical evaluation of NO_x emission control methods applicable to reciprocating engines.

In the engine modification category, only lean-burn technology and derating power output are considered as technically feasible for this project. Although retarding ignition timing and exhaust gas recirculation can be applied to rich-burn engines, the NO_x emissions are greater than those from a comparable lean-burn engine. Steam/water injection, air-to-fuel ratio changes and EGR for lean-burn engines are considered technically infeasible and will not be reviewed further. The application of these methods to rich-burn engines results in emission rates higher than that of the unit proposed for installation, so they need not be considered further.

In the add-on control technology category, only the lean-burn engine/SCR combination and rich-burn engine/NSCR combination are considered technically feasible. Other methods such as the NO_xOUT process, Thermal DeNO_x, and the lean-burn engine/NSCR combination are considered technically infeasible.

6.2.6 Evaluation of Technically Feasible NO_x Control Methods

This section examines the four technically feasible NO_x control methods identified in the previous discussion. The control methods, which include lean-burn engine design, achieve a NO_x control level that is equal to or greater than rich-burn technology. The four control alternatives are ranked according to their total removal effectiveness. Each alternative is examined further in regards to technical issues, environmental effects, energy requirements and impacts, and economic impacts.

TABLE 6-2

Summary of Technical Feasibility of NO_x Emission Controls for Reciprocating Engines

Control Technology	NO_x Controlled Emission Rate	Technical Feasibility	Comments
Engine Modification Alternatives			
Steam Injection	Not Applicable	No	Technically infeasible due to irreversible structural damage to engine block.
Air-to-fuel Ratio Change (or Lean-Burn Technology)	2.0 g/bhp-hr	Yes	Lowest emission rate achievable by engine modification, at least 80% control efficiency.
Retarding Ignition Timing Rich-burn Engine Lean-burn Engine	 9.4 g/bhp-hr Not Applicable	 Yes No	Engine timing retard between 2° and 6°; average 15% NO_x reduction.
Derating Power Output Rich-burn Engine Lean-burn Engine	 7.2 g/bhp-hr 1.3 g/bhp-hr	 Yes Yes	Average 35% NO_x reduction at 25% of engine power derated for gas-fired engines as a group. NO_x reductions for turbo charged engines are less due to the lower effect on air-to-fuel ratio.
Exhaust Gas Recirculation Rich-burn Engine Lean-burn Engine	 7.3 g/bhp-hr Not Applicable	 Yes No	Maximum 34% NO_x reduction from standard engine. Ineffective for lean-burn engine.
Add-on Control Technology*			
NO_xOUT Process	Not Applicable	No	Technically infeasible (1000-1600°F), cost prohibitive for high temperature auxiliary equipment.
THERMAL $DeNO_x$	Not Applicable	No	Technically infeasible (above 1000°F), cost prohibitive for high temperature auxiliary equipment.
Lean-Burn Engine/NSCR	Not Applicable	No	Technically infeasible for lean-burn engine, require <4% 0_2 conc. in the exhaust stream.
Lean-Burn Engine/SCR	0.4 g/bhp-hr	Yes	Applicable to lean-burn engine with control efficiency of 80 percent.
Rich-Burn Engine/NSCR	1.1 g/bhp-hr	Yes	Applicable to rich-burn engine only, required greater than 4% 0_2 conc. In exhaust gas stream. Control efficiency of 90%.

* Except for the rich-burn engine/NSCR option, all add-on control technologies are for lean-burn engines.

6.2.6.1 Ranking of Feasible Control Technologies

The top-down BACT approach requires the ranking of the NO_x emission control alternatives by achievable emission levels. The four options, ranked in order of removal effectiveness, are:

- lean-burn engine with SCR,
- rich-burn engine with NSCR,
- lean-burn engine with derating,
- lean-burn engine.

A baseline condition must be established for BACT ranking and economic analysis. The baseline is defined as the uncontrolled rate of the process under review. Therefore, the baseline condition for the emissions of stationary reciprocating engines would be the emission factor for a heavy-duty, natural gas-fired pipeline compressor engine with a NO_x emission level of 11 grams/bhp-hr, as found in AP-42 (USEPA, 1985).

Presented in Table 6-3 is the BACT top-down hierarchy of the technically feasible NO_x emission control technologies, their corresponding NO_x emission rates, and their control efficiencies calculated from their baseline emission level.

6.2.6.2 Analysis of Lean-Burn Engine with SCR

Technical Issues

As the most effective NO_x abatement process in terms of removal efficiency, SCR technology has been applied for control of NO_x emissions from state-of-the-art reciprocating engines. However, the reliability of SCR's performance on reciprocating engines has not been consistently demonstrated. Data on sustained NO_x reduction performance for reciprocating engines are very limited.

Technical concerns involved in SCR use are the narrow operating temperature range and the possible damage to the catalyst and downstream equipment. A stack gas reheat system would be required to heat the exhaust gases to the SCR's operating temperature (see further discussion under Energy Requirements and Impacts). The integration of a reheat system adds another design criteria to an already complex system consisting of SCR components and an ammonia handling system.

TABLE 6-3

BACT "Top-Down" Hierarchy of NO_x Control Technologies

BACT Ranking	Technology	Brake Emission Rate (g/bhp-hr)	Annual Emissions (TPY)	Total Emission Reduction (TPY)*	Total Control Efficiency (%)*
First	Lean-burn Engine with SCR	0.4	15.4	409.5	96%
Second	Rich-burn Engine with NSCR	1.1	42.5	382.4	90%
Third	Lean-burn Engine/Derating Power+	1.3	50.2	374.7	88%
Fourth	Lean-burn Engine	2.0	77.2	347.7	82%
Baseline	Rich-burn Engine	11.0	424.9	-	-

* Total emission reduction and total control efficiency are calculated from baseline emission level.

\+ The range of control effectiveness is dependent on the percent of engine's rated torque. The calculated values are based on 35% NO_x reduction at 25% derated power (or 75% rated torque).

Ammonia is used as a reactant for the NO_x reduction reactions. Excess ammonia use can cause formation of ammonium bisulfate compounds under irregular operating conditions. These compounds can act as catalyst poisoning agents and can damage metal ductwork downstream. Thus, the SCR system requires a strict maintenance service schedule that includes manual cleaning every 2,000 to 2,500 hours of operation (Steuler, 1990a). Cleaning consists of blowing the catalyst surfaces with a compressed air gun and vacuuming out soot.

In California, the South Coast Air Quality Management District (SCAQMD, 1984) reported SCR demonstration tests on seven reciprocating engines. The report indicated that only one SCR system was able to complete the 4,000 hours of continuous testing; the other six engine/SCR units failed for a variety of reasons including poor catalyst performance and problematic ammonia injection operation. A recent survey report by the Gas Research Institute on SCR (GRI, 1990) states:

> A total of 13 SCR units are currently installed on reciprocating engines. Only one unit involves gas transmission. A number of operational problems impacting SCR performance and engine operation have been documented. At least three SCR units applied to reciprocating engines are scheduled to be replaced with alternative controls....

A review of the BACT determinations made to date on gas-fired reciprocating engines (Table 6-1) reveals that SCR has never been applied specifically to any large-bore (i.e., greater than 1,000 bhp) and low-speed (i.e., 300 rpm) lean-burn engines due to their already low NO_x emission rate.

Application of SCR on gas-fired engines has been limited to small-bore, high-speed engines typically less than 1,000 bhp, at 900 rpm or greater (i.e., ANR Production Company's 600-bhp engine, see Table 6-1), and Shell California Production's 600-bhp engine (See Appendix I). The only SCR application to a large-bore reciprocating engine was reported for Pfizer, Inc.'s cogeneration facility in Massachusetts (1990). This project involved a 6,710-bhp engine with an estimated uncontrolled NO_x emission rate between 5 and 12 grams/bhp-hr for dual-fuel (94% natural gas, 6% diesel) and diesel fuel, respectively (see Appendix I). However, Pfizer's engine differs from FGTC's proposed engine in both fuel fired and application.

On September 5, 1990, a PSD permit was issued to Northern Natural Gas Company (Northern Natural Gas Co., 1990) for a gas-fired 4,000-bhp gas compressor engine in Iowa. The Iowa Department of Natural Resources (IDNR), indicated that "application of SCR systems to the engine as applied for would represent a transfer of technology since none are known to be operational." IDNR further found such "technology transfer to be unreliable at best with a high percentage of down time likely." Therefore, SCR was rejected as BACT by IDNR due to its uncertain reliability.

Environmental Effects

The add-on SCR technology for NO_x control will pose other potential adverse environmental impacts such as accidental spills and emissions of ammonia, and solid waste disposal for the non-inert spent catalyst. These issues are briefly described in the following discussion.

The SCR system requires the use of ammonia as reagent to convert NO_x to nitrogen gas and water. The main environmental issues include delivery, handling, and storage of ammonia, which pose inherent safety and health risks in the event of accidental releases. In proposing NO_x abatement regulations for stationary gas turbines, California's South Coast Air Quality Management District (SCAQMD) performed a risk assessment of spill handling and storage of ammonia. The study concluded that ammonia handling and storage associated with the operation of a SCR system could realistically present serious consequences, and recommended further consideration of potential impacts and mitigation measures (SCAQMD, 1979). Generally, aqueous ammonia systems (normally between 25 to 29% ammonia concentration) are used at installations located in populated areas. However, such practice increases the complexity, size, and the cost of the ammonia system since greater amounts of aqueous ammonia must be handled and stored than for SCR systems that use anhydrous ammonia.

Ammonia slippage is a normal occurrence during operation of SCR control equipment. NO_x abatement system suppliers generally report ammonia slippage levels of 10 ppm.

Spent catalysts of the metal oxides type must be disposed of properly. Typically, a metal oxide catalyst contains approximately 5% vanadium pentoxide (V_2O_5). In pure commercial form, V_2O_5 is considered a hazardous material by the USEPA. Ceramic-based, honeycomb-shaped catalysts such as zeolite can be landfilled due to the inert intrinsic properties of ceramic materials.

Energy Requirements and Impacts

The add-on technology of SCR imposes the following energy penalties:

- Additional energy requirements to compensate for power loss due to additional back pressure from the SCR;

- Electrical requirements for heating the ammonia solution and operating the injection system; and

- Additional energy necessary for reheating the proposed engine exhaust gases from 540°F up to the SCR operating range of 700°F [SCR manufacturers specify a typical operating temperature window between 600°F to 900°F (Engelhard, 1990a,b,c; and Steuler, 1990)].

Using the lean-burn engine will result in better fuel economy than the baseline rich-burn engine; however, the addition of SCR would require a minimum of 4.19 MMBtu/hr or 36,733 MMBtu/yr for stack gas reheating. This reduces the net fuel savings for a lean-burn engine with SCR to 59,000 MMBtu/yr from the original 4.2 MMBtu/hr or 36,792 MMBtu/yr fuel savings of a rich-burn engine.

Economic Analysis

A cost summary for two lean-burn engines, each equipped with a SCR NO_x control system is presented in Table 6-4. The additional capital cost, both direct and indirect, for this control option is $1,389,146. This includes $618,000 for hardware (SCR system, lean-burn engine, exhaust reheat ductwork, monitoring equipment and support structures) and $67,980 in freight and taxes.

The annualized cost resulting from installation of this system is $725,999. This is based on a direct operating cost (labor and material) of $296,778, and indirect operating cost of $203,207 and a cost recovery factor of $226,014.

The total and incremental cost effectiveness is $1,773/ton and $19,205/ton, respectively. The total cost effectiveness is based on a total NO_x removai efficiency of 96% which corresponds to a total annual reduction of 409.5 tons from the baseiine engine. The incremental cost value is based on the SCR system decreasing NO_x emissions by 27.1 TPY from those which would occur with the next most stringent technology.

6.2.6.3 Analysis of Rich-Burn Engine with NSCR

Technical Issues

Because they operate at near stoichiometric air-to-fuel ratios, rich-burn engines generate cylinder temperatures in the range of 1,200°F to 1,300°F. Engine manufacturers have found that such high temperatures do not allow high engine loading. For greater power output, engine manufacturers have found that engine modifications (i.e., turbocharged engines which can produce more power enhancements with lower emission levels) are a better choice than building

TABLE 6-4

Summary of Capital and Operating Costs for Lean-burn Engine and SCR NO_x Controls

Direct Capital Cost	$ 891,774
Indirect Capital Cost	$ 497,372
Total Capital Cost	$1,389,146
Direct Operating Costs	$ 296,778
Overhead	$ 147,641
Capital Charges at 16.27 percent of Capital Cost	$ 226,014
G&A, Taxes, and Insurance at 4 percent	$ 55,566
Interest on Working Capital	Neglected
Total Annual Costs	$ 725,999
Total NO_x Removed	409.5 tpy
Total Cost Effectiveness	$ 1,773 per ton

NOTE: See Appendix G for cost details.

larger engine blocks. In the current U.S. market, rich-burn engines over 2,000 bhp are not standard off-the-shelf items; however, a 4,000-bhp engine can be obtained by special order.

Normally, rich-burn engine/NSCR combination applications are found only on small engines of approximately 1,000 bhp or less (i.e., a 600-bhp engine for ANR Production Company, Virginia; a 380-bhp engine for De La Guerra Power, Inc., California; and a 200-bhp engine for Richmond Exploration Corp., California; see Appendix I). The application of NSCR to an engine the size to be installed at Compressor Station No. 20 may pose unforeseen technical problems not encountered in installations on smaller units.

Environmental Effects

Environmental impacts are expected to be minimal for the rich-burn engine/NSCR option since no toxic or hazardous reagents are required, and rich-burn/NSCR technology generally produces lower CO and VOC emissions than a lean-burn engine. Catalyst disposal will be required when using NSCR. Most vendors guarantee a service life of 3 years for the catalyst system.

Energy Requirements and Impacts

The NSCR converter does not require any additional fuel other than a small amount of hydrocarbon fuel used for injection into the exhaust gas mixture to ensure fuel rich conditions. The fuel economy of the rich-burn engine is approximately 8,000 Btu/bhp-hr compared to the 6,950 Btu/bhp-hr for the proposed lean-burn engine. For a 4,000-bhp output, an additional 4.2 MMBtu/hr heat input is required, or approximately 36,792 MMBtu/yr for an annual cost of $75,792.

Economic Analysis

Capital and annualized cost estimates were prepared for two rich-burn engines, each equipped with a NSCR converter. Cost of the NSCR converter was provided by Johnson-Matthey as $80,000 per unit. The NSCR can achieve 90% NO_x reduction. The resulting NO_x emission rate is 1.1 grams/bhp-hr.

The control costs for two NSCR converters designed for a 4,000-bhp rich-burn engine are summarized in Table 6-5. The direct capital cost is calculated to be $159,307, and the indirect capital cost is calculated to be $93,533. The total capital investment is $252,841.

TABLE 6-5

Summary of Capital and Operating Costs for Rich-burn Engine and NSCR NO_x Controls

Direct Capital Cost	$ 159,307
Indirect Capital Cost	$ 93,533
Total Capital Cost	$ 252,841
Direct Operating Costs	$ 109,207
Overhead	$ 45,075
Capital Charges at 16.27 percent of Capital Cost	$ 41,137
G&A, Taxes, and Insurance at 4 percent	$ 10,114
Interest on Working Capital	Neglected
Total Annual Costs	$ 205,533
Total NO_x Removed	382.4 tpy
Total Cost Effectiveness	$ 537 per ton

NOTE: See Appendix G for cost details.

The annualized cost resulting from installation of a rich-burn engine equipped with an NSCR catalyst is $205,533. This is based on direct and indirect operating costs presented above and a cost recovery factor of $41,137.

The total and incremental cost effectiveness are $537/ton and $6,415/ton, respectively. The total cost effectiveness is based on a total NO_x removal efficiency of 90% which corresponds to an total annual reduction of 382.4 ton from the baseline engine. The incremental cost value is based on the NSCR system decreasing NO_x emissions by 34.7 TPY from those which would occur with the next most stringent technology.

6.2.6.4 Analysis of Lean-Burn Engine with Derating Power Output

Technical Issues

Derating power output does not require additional equipment. Derating involves restricting the engine torque to a level below its normal operating design rate. To derate an engine the throttle valve setting is adjusted to change the power output. Although a derated engine produces less NO_x emissions, derating reduces the overall engine efficiency and shortens its service life as much as 25% (Dresser-Rand, 1990). In addition, continuous derating operation would require a bigger, more expensive engine to meet the overall power requirement. Derating power output is not considered BACT for the proposed lean-burn engine because of potential engine reliability problems, shortened engine life, and increased emissions of CO and hydrocarbons.

Environmental Effects

Application of this technology would result in lower NO_x emissions, but emissions of carbon monoxide and hydrocarbon would increase. Dresser-Rand has reported a 40% reduction of NO_x emissions with a corresponding increase of 28% in carbon monoxide (CO) emissions and 48% increase in total hydrocarbon emissions based on a 30% derating of a 4,000-bhp lean-burn engine.

Energy Requirements and Impacts

In general, derating an engine will result in less fuel economy. USEPA (1979) reported a fuel penalty of 8% based on derating a dual-fuel engine by 25%. Manufacturers of gas-fired reciprocating engines state that derating by 30% increases fuel consumption by approximately 8%.

Economic Analysis

If derating is used, a larger engine would be necessary to meet the FGTC's requirement of 4,000 bhp. Derating larger engines will increase both the capital cost and annual operating cost for the proposed compressor engines, and will severely impact the component's durability. Since the proposed engine requires a high reliability at various power settings, derating larger engines is not considered feasible. A detailed economic analysis was not performed for this technology.

6.2.6.5 Analysis of Lean-Burn Engine

Technical Issues

The proposed turbocharged reciprocating engine will operate according to the manufacturer's specified operating parameters. The engine's state-of-the-art design includes small pre-ignition chambers in which a rich fuel mixture is spark-ignited. The hot gases then enter the main combustion chambers and create spontaneous combustion of the lean fuel mixture. As a result, the overall combustion process is conducted under very lean fuel conditions. Operating on the lean side of the air-to-fuel ratio allows the proposed engine to obtain peak fuel economy.

In general, thermal NO_x formation is directly proportional to the combustion temperature and residence time of the combustion gases (USEPA, 1979). The high mass flow rate at full-load, as indicated by the 67,476 pounds per hour of exhaust mass flow rate, reduces the residence time of the combustion gases compared to a rich-burn engine, which operates at an air-to-fuel ratio near unity. High mass flow rate also means the engine operates below the peak temperature region for thermal NO_x formation. The exhaust temperature for the proposed engine is 540°F, which falls in the range of typical exhaust temperatures for reciprocating engines. Thus, the rate of thermal NO_x formation is equal to the conventional rich-burn engine.

Environmental Effects

There are no adverse environmental impacts expected for using the lean-burn engine, since there is no wastewater or solid waste created. Emissions to the atmosphere are less than for the baseline rich-burn engine and do not result in significant impacts (see section 4.0).

Energy Requirements and Impacts

The lean-burn engine is more fuel efficient than a comparable rich-burn engine. The fuel saving is 4.2 MMBtu/hr for a total annual savings of 36,792 MMBtu/yr.

Economic Analysis

Capital and annualized cost estimates were prepared for the lean-burn engine proposed for Compressor Station No. 20. The differential engine cost of the lean-burn engine compared to the baseline rich-burn engine was obtained from other recent permit applications submitted by FGTC. The engine has a guaranteed NO_x emission limit of 2.0 grams/bhp-hr.

Control costs for the engine are summarized in Table 6-6. The differential engine cost for the Cooper-Bessemer 10V-275C engine is approximately $100,000 per unit, from which the direct capital cost is calculated to be $158,730, and the indirect capital cost is calculated to be $68,254. The total capital investment is $226,984.

The direct operating cost includes $7,937 for normal maintenance of the lean-burn technology components of the engine and a fuel credit of $75,792 for better fuel efficiency compared to the baseline rich-burn engine. The indirect operating cost is $13,841 and the capital recovery cost is $36,930. The annualized cost is -$17,083 for the lean-burn engine.

The total and incremental cost effectiveness is $-49/ton. The total cost effectiveness is based on a total NO_x removal efficiency of 82% which corresponds to a total and incremental reduction of 347.7 tons from the baseline engine.

6.2.7 NO_x BACT Summary and Conclusion

The BACT analysis for NO_x control has identified three feasible control alternatives: the lean-burn engine with SCR, the rich-burn engine with NSCR, and the lean-burn engine. Selection of a control technology as BACT will be based on comparison of the overall environmental, energy, and economic impacts. The most effective control alternative not eliminated will be selected as BACT.

6.2.7.1 Comparison of Environmental Effects

The lean-burn engine does not create any waste; therefore, it is the best alternative in terms of the environmental impact analysis. SCR poses the greatest potential for toxic impacts due to ammonia handling and storage and ammonia slip. When the alternatives are compared in terms of adverse environmental impacts the lean-burn engine with SCR is the worst due to potential ammonia release and disposal of the catalysts. The rich-burn engine with NSCR is the next worst option due to disposal of catalyst.

TABLE 6-6

Summary of Capital and Operating Costs for Lean-burn Engine NO_x Controls

Direct Capital Cost	$ 158,730
Indirect Capital Cost	$ 68,254
Total Capital Cost	$ 226,984
Direct Operating Costs	$ - 67,855
Overhead	$ 4,762
Capital Charges at 16.27 percent of Capital Cost	$ 36,930
G&A, Taxes, and Insurance at 4 percent	$ 9,080
Interest on Working Capital	Neglected
Total Annual Costs	$ -17,083
Total NO_x Removed	347.7 tpy
Total Cost Effectiveness	$ -49 per ton

NOTE: See Appendix I for cost details.

6.2.7.2 Comparison of Energy Impacts

The lean-burn engine shows a savings of 36,792 MMBtu/yr in heat input over the rich-burn engine because of its inherent fuel efficient design. Therefore, a lean-burn engine has no energy impact compared to the other BACT options evaluated. The addition of SCR to a lean-burn engine imposes a fuel requirement of 36,733 MMBtu/yr for stack gas reheat. In addition, electrical power is required for the ammonia vaporizer and injection system. The rich-burn engine with NSCR has the highest energy requirements. Operating a rich-burn engine requires an additional 36,792 MMBtu/yr of heat input compared to using an engine with lean-burn technology. Thus, the lean-burn engine is the best alternative in view of the energy impact analysis.

6.2.7.3 Comparison of Economic Analysis

When the three feasible NO_x control alternatives are compared in terms of total cost effectiveness, the lean-burn engine/SCR technology has the highest cost effectiveness value of $1,723 per ton of NO_x removed. The rich-burn engine/NSCR technology is the next highest with $537 per ton of NO_x removed. The lean-burn engine has a nominal total cost effectiveness value of $ -49 per ton of NO_x removed.

The incremental cost effectiveness values for the lean-burn engine/SCR technology and the rich-burn engine/NSCR technology are $13,345 and $6,415 per ton of NO_x removed, respectively. The lean-burn engine has an incremental cost effectiveness of $-49 per ton of NO_x removed. Therefore, the lean-burn engine is the most cost effective control option.

The detailed cost estimating procedure is presented in Appendix I.

6.2.7.4 NO_x Control Summary

Based on the top-down BACT analysis, the proposed Cooper-Bessemer 10V-275C lean-burn engine is BACT for FGTC's proposed modification to Compressor Station No. 20. The environmental, energy, and economic impacts are summarized in Table 6-7. Both the lean-burn engine/SCR and the rich-burn engine/NSCR control options are eliminated primarily due to their high total and incremental cost effectiveness values for NO_x control. Recently, it has been determined by the FDER that incremental cost effectiveness values of $4,000 to $5,000 per ton of NO_x removed are unreasonable. These values were established for much larger sources of NO_x, such as utility gas turbine combined-cycle projects. In addition, add-on control technologies have significant energy penalties along with potential adverse environmental impacts, and these systems are not fully proven on IC engines of the size proposed by FGTC.

Table 6-7
Summary of Top-Down BACT Impact Analysis Results for NOx for a Stationary IC Reciprocating Engine

Control Alternative	Annual Emissions (TPY)*	Total Emission Reduction (TPY)*	Incremental Emission Reduction (TPY)*	Environmental Impacts: Potential Toxic Air Impact?	Environmental Impacts: Potential Adverse Environmental Impacts?	Energy Impacts Incremental Increase over baseline: Natural Gas (MMBtu/yr)	Energy Impacts Incremental Increase over baseline: Electricity (MW-hr/yr)	Total Annualized Cost ($/yr)	Economic Impacts: Incremental Annualized Cost ($/yr)	Economic Impacts: Total Cost Effectiveness ($/ton)	Economic Impacts: Incremental Cost Effectiveness ($/ton)
Lean-Burn Engine with SCR	15.4	409.5	27.1	Yes	Yes	(59)	12	$725,999	$520,466	$1,773	$19,205
Rich-Burn Engine with NSCR	42.5	382.4	34.7	No	No	36,792	0	$205,533	$222,616	$537	$6,415
Lean-Burn Engine	77.2	347.7	347.7	No	No	(36,792)	0	($17,083)	($17,083)	($49)	($49)
Baseline (rich-burn engine)	424.9	-----	-----	---	---	-----	---	-----	-----	---	---

* Total emission reduction, total annualized cost effectiveness are calculated based on similar baseline parameter values.
** Incremental values are based on the next lower control technology's parameter values.

With lean-burn/SCR and rich-burn/NSCR options eliminated, the lean-burn engine is BACT. This is consistent with current BACT determinations shown in Table 6-1 for similar source applications. In the most recent top-down BACT analysis, IDNR has concluded that the inherently low NO_x emitting lean-burn engine is BACT for Northern Natural Gas Company. In its BACT summary, IDNR rejected SCR on the grounds of uncertain reliability and unreasonable cost effectiveness. No other stationary IC sources, whether in natural-gas-related applications or other industrial processes, which use similar fuel and equivalent engines (i.e., natural-gas-fired and 4,000-bhp lean-burn engine) have been required to bear a high incremental cost effectiveness to reduce NO_x emissions.

6.3 BACT Summary

FGTC has conducted a top-down BACT analysis for NO_x from the proposed compressor engine at Compressor Station No. 20. The conclusions and key analysis results are summarized in this section.

The proposed BACT level for NO_x is 2.0 grams/bhp-hr based on a reciprocating engine using lean-burn technology. Two types of potential NO_x control technology alternatives were evaluated: engine modifications and post-combustion controls that treat the exhaust gas stream.

Engine modifications included steam/water injection, air-to-fuel ratio changes, retarded ignition timing, derating power output, and exhaust gas recirculation. The air-to-fuel ratio option is incorporated in the lean-burn engine design. Steam/water injection was rejected as technically infeasible. Retarded ignition timing, and exhaust gas recirculation were rejected as technically infeasible for lean-burn engines. Engine derating was rejected because of concerns regarding engine inefficiency and economic impacts.

Four potential post-combustion control options were considered: NO_xOUT, Thermal DeNO_x, selective catalytic reduction (SCR), and nonselective catalytic reduction (NSCR). Thermal DeNO_x and NO_xOUT were rejected as not commercially available and is technically infeasible for reciprocating engines. SCR and NSCR were rejected on the basis of adverse cost, economic and environmental impacts.

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APPENDIX A

APPLICATION TO OPERATE/CONSTRUCT AIR POLLUTION SOURCE

Florida Department of Environmental Regulation

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

Lawton Chiles, Governor — Carol M. Browner, Secretary

AC 56-230129

PSD-FL-203

RECEIVED

APR 23 1993

Bureau of Air Regulation

APPLICATION TO OPERATE/CONSTRUCT AIR POLLUTION SOURCES

SOURCE TYPE: Natural Gas Compressor Engine [X] New[1] [ ] Existing[1]

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

COMPANY NAME: Florida Gas Transmission Company COUNTY: St. Lucie

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) Station 20, Unit No. 5

SOURCE LOCATION: Street 8701 Orange City Ft. Pierce

UTM: East 558.01 km North 3,035.68 km

Latitude 27 ° 26 ' 43 "N Longitude 80 ° 24 ' 47 "W

APPLICANT NAME AND TITLE: Carl D. Schulz, Vice President, Project Management Services, Florida Gas Transmission Company, (713) 853-3893

APPLICANT ADDRESS: P.O. Box 1188, Houston, Texas 77251-1188

SECTION I: STATEMENTS BY APPLICANT AND ENGINEER

A. APPLICANT

I am the undersigned owner or authorized representative* of Florida Gas Transmission Company

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: [signature]

Carl D. Schulz, Vice President, Project Management Services

Name and Title (Please Type)

Date: ________ Telephone No. (713) 853-3893

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

This is to certify that the engineering features of this pollution control project have been [redacted]/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, t

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

DER Form 17-1.202(1)
Effective October 31, 1982

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 Barry D. Andrews

Name (Please Type)

Company Name (Please Type)

Mailing Address (Please Type)

Florida Registration No. 36024 Date: 4-14-93 Telephone No. (205) 740-8240

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.

See Application report. Section 1.0 - Facility Description

Section 2.0 - Project Description

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

Start of Construction February 1994 Completion of Construction December 1994

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.)

Not Applicable

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

Not Applicable

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.

See Application report. Section 1.0 - Facility Description

Section 2.0 - Project Description

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

Start of Construction February 1994 Completion of Construction December 1994

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.)

Not Applicable

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

Not Applicable

E. Requested permitted equipment operating time: hrs/day 24 ; days/wk 7 ; wks/yr 52 ;

if power plant, hrs/yr ______ ; if seasonal, describe: Not Applicable

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? ______

   b. If yes, has "Lowest Achievable Emission Rate" been applied? ______

   c. If yes, list non-attainment pollutants. ______

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

3. Does the State "Prevention of Significant Deteriotiration" (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? No

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? ______

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

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

See Application Report.

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

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

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

B. Process Rate, if applicable: (See Section V, Item 1)

1. Total Process Input Rate (lbs/hr): Not Applicable
2. Product Weight (lbs/hr): Not Applicable

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

Emission Point 2005

Name of Contaminant	Emission[1] Maximum lbs/hr	Emission[1] Actual T/yr	Allowed[2] Emission Rate per Rule 17-2	Allowable[3] Emission lbs/hr	Potential[4] Emission lbs/yr	Potential[4] Emission T/yr	Relate to Flow Diagram
NO_x	52.92	77.3			52.92	77.3	
CO	26.46	81.1			26.46	81.1	
VOC	12.35	23.18			12.35	23.18	
SO_2	0.84	3.33			0.84	3.33	
PM	0.15	0.6			0.15	0.6	

[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).

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

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

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

B. Process Rate, if applicable: (See Section V, Item 1)

1. Total Process Input Rate (lbs/hr): Not Applicable

2. Product Weight (lbs/hr): Not Applicable

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

Emission Point 2011

Name of Contaminant	Emission[1] Maximum lbs/hr	Emission[1] Actual T/yr	Allowed[2] Emission Rate per Rule 17-2	Allowable[3] Emission lbs/hr	Potential[4] Emission lbs/yr	Potential[4] Emission T/yr	Relate to Flow Diagram
NO_x	1.35	0.27			1.35	0.27	
CO	2.95	0.59			2.95	0.59	
VOC	0.06	0.01			0.06	0.01	
SO_2	0.14	0.03			0.14	0.03	
PM	0.03	0.005			0.03	0.005	

[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)

E. Fuels

Type (Be Specific)	Consumption*		Maximum Heat Input (MMBTU/hr)
	avg/hr	max./hr	
	0.025	0.0267	27.80

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

Fuel Analysis:

Percent Sulfur: 0.031 (by weight) Percent Ash: N/A

Density: 0.0455 lb/ft^3 lbs/gal Typical Percent Nitrogen: N/A

Heat Capacity: 22,857 BTU/lb N/A BTU/gal

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

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

Annual Average N/A Maximum N/A

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

Not Applicable

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

Emission Point 2005

Stack Height: 65 ft. Stack Diameter: 4 ft.

Gas Flow Rate: 34,928 ACFM ______ DSCFM Gas Exit Temperature: 540 °F.

Water Vapor Content: ______ % Velocity: 46.32 FPS

SECTION IV: INCINERATOR INFORMATION

Not Applicable

Type of Waste	Type O (Plastics)	Type I (Rubbish)	Type II (Refuse)	Type III (Garbage)	Type IV (Pathological)	Type V (Liq.& Gas By-prod.)	Type VI (Solid By-prod.)
Actual lb/hr Incinerated							
Uncontrolled (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 Type	Fuel BTU/hr	Temperature (°F)
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) ______

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

Emission Point 2011

Stack Height: 22 ft. Stack Diameter: 0.5 ft.

Gas Flow Rate: 3,043 ACFM ______ DSCFM Gas Exit Temperature: 1112 °F.

Water Vapor Content: ______ % Velocity: 258.3 FPS

SECTION IV: INCINERATOR INFORMATION

Type of Waste	Type 0 (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 Type	Fuel BTU/hr	Temperature (°F)
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 Application Report, Section 2.0, Appendix C, D
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. See Application Report, Appendix C, D
3. Attach basis of potential discharge (e.g., emission factor, that is, AP42 test).
   See Application Report, Appdendix C, D
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.)
   Not Applicable
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).
   Not Applicable
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 Application Report, Figure 2-1
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 Application Report, Figure 1-1, 2-1
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 Application Report, Appendix B

9. The appropriate application fee in accordance with Rule 17-4.05. The check should be made payable to the Department of Environmental Regulation.

Submitted Separately

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.

Not Applicable

SECTION VI: BEST AVAILABLE CONTROL TECHNOLOGY

See Application Report, Section 3.0 and 6.0

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

[ ] Yes [ ] No

Contaminant	Rate or Concentration

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

[ ] Yes [ ] No

Contaminant	Rate or Concentration

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

Contaminant	Rate or Concentration

D. Describe the existing control and treatment technology (if any).

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

*Explain method of determining

Useful Life: f. 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).

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:

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

Refer to Application Report

A. Company Monitored Data

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

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

Pollutant	Emission Rate	
TSP	____________________	grams/sec
SO^2	____________________	grams/sec

E. Emission Data Used in Modeling

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.

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.

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.

APPENDIX B

PLOT PLAN

APPENDIX C

SITE SUMMARY TABLE

Phase III Station Characteristics

20-Apr-93
CS20.WK1

Compressor Station:	Number 20
Name:	Ft. Pierce
County:	St. Lucie
Nearest City:	Ft. Pierce
Compressor Supervisor:	Donnie Owings
Mailing Address:	8701 Orange Ft. Pierce, Florida 34945
Telephone:	407-466-6277
Latitude:	27-26-43
Longitude:	80-24-47
UTM Zone:	17
UTM Easting:	558.01 km
UTM Northing:	3,035.68 km
Elevation (ft):	22

ENGINE IDENTIFICATION	2005
Phase III Engine Characteristics	
Operating Time (hr/yr)	8760
Hours/Day	24
Days/Week	7
Engine Type	Recip.
Manufacturer	Cooper - Bessemer
Model	10V-275C
Horsepower Rating (hp)	4000
Air Charging	Turbo
Exhaust Temperature (F)	540
Mass Flow Rate (lbs/hr) (a)	80,640
Volumetric Flow Rate (acfm)	34,928
Volumetric Flow Rate (dscfm)	18,163
Nominal Fuel Consumption (MMscfh) (b)	0.0267
Max. Fuel Consumption (MMscfh) (b)	0.0294
Nominal Specific Fuel Consump. (Btu/bhp-hr)	6,950
Maximum Specific Fuel Consump. (Btu/bhp-hr)	7,650
Nominal Heat Input (MMBtu/Hr)	27.8
Maximum Heat Input (MMBtu/Hr)	30.6
Phase III Stack Parameters	
Stack Height (ft)	65.00
Stack Diameter (ft)	4.00
Stack to Building Offset (ft)	24.00
Building Height (ft) (c)	41.00
Building Length (ft) (c)	72.00
Building Width (ft) (c)	60.00
Phase III Fuel Characteristics	
Fuel Type	N.G.
Heating Value (Btu/CF)	1040
Heat Capacity (Btu/lb)	22,857
Density (lb/cubic ft)	0.0455
Percent Sulfur (%) (d)	0.031
Percent Ash (%)	N/A

ENGINE IDENTIFICATION 2005

Phase III Emissions Rates by Engine for Station 20

		Nominal	Maximum
Grams/BHP-Hour			
	NOX	2.000	6.000
	CO	2.100	3.000
	NMHC	0.600	1.400
	SO2 (e)	0.086	0.095
	PM (f)	0.015	0.017
Pounds/Hour			
	NOX	17.64	52.92
	CO	18.52	26.46
	NMHC	5.29	12.35
	SO2	0.76	0.84
	PM	0.13	0.15
Tons/Year			
	NOX	77.26	
	CO	81.12	
	NMHC	23.18	
	SO2	3.33	
	PM	0.57	

Notes:
(a) Wet mass flow (@ 60 F, 14.7 psi).
(b) Based on heating value of fuel gas.
(c) Engine enclosed in building.
(d) Percent by weight.
(e) Based on 10 grains S/100 SCF n.g. (assume full conversion).
(f) Based AP-42 factor of 5 lbs/MMSCF.

Phase III Station Characteristics

Compressor Station:	Number 20
Name:	Ft. Pierce
County:	St. Lucie
Nearest City:	Ft. Pierce
Compressor Supervisor:	Donnie Owings
Mailing Address:	8701 Orange Ft. Pierce, Florida 34945
Telephone:	407-466-6277
Latitude:	27-26-43
Longitude:	80-24-47
UTM Zone:	17
UTM Easting:	558.01 km
UTM Northing:	3,035.68 km
Elevation (ft):	22

ENGINE IDENTIFICATION	2011
Phase III Emergency Generator Characteristics	
Operating Time (hr/yr)	400
Engine Type	Recip.
Manufacturer	Caterpillar
Model	398 TA-LCR
Horsepower Rating (hp)	625
Kilowatt Rating (kw)	450
Exhaust Temperature (F)	1112
Volume Air to Fuel Ratio	9.5:1
Exhaust Flow (acfm)	3,043
Air Flow (kg/hr)	1,929
Nominal Fuel Consumption (MMscfh) (b)	0.0050
Max. Fuel Consumption (MMscfh) (b)	0.0050
Brake Specific Fuel Consump. (Btu/bhp-hr)	8,387
Maximum Heat Input (MMBtu/Hr)	5.24
Phase III Stack Parameters	
Stack Height (ft)	22
Stack Diameter (ft)	0.5
Stack to Building Offset (ft)	5
Building Height (ft) (c)	21
Building Length (ft) (c)	135
Building Width (ft) (c)	25
Phase III Fuel Characteristics	
Fuel Type	N.G.
Heating Value (Btu/CF)	1040
Heat Capacity (Btu/lb)	22,857
Density (lb/cubic ft)	0.0455
Percent Sulfur (%) (d)	0.031
Percent Ash (%)	N/A

ENGINE IDENTIFICATION 2011

Phase III Emissions Rates for Emergency Generator at Station 20

Grams/BHP-Hour		
	NOX	0.980
	CO	2.140
	NMHC	0.040
	SO2 (e)	0.105
	PM (f)	0.018
Pounds/Hour		Maximum
	NOX	1.350
	CO	2.950
	NMHC	0.055
	SO2	0.144
	PM	0.025
Tons/Year		Restricted (400 hrs/yr)
	NOX	0.270
	CO	0.590
	NMHC	0.011
	SO2	0.028
	PM	0.005

Notes:
(a) Wet mass flow (@ 60 F, 14.7 psi).
(b) Based on heating value of fuel gas.
(c) Engine enclosed in auxillary building.
(d) Percent by weight.
(e) Based on 10 grains S/100 SCF n.g. (assume full conversion).
(f) Based AP-42 factor of 5 lbs/MMSCF.

APPENDIX D

SUPPORTING CALCULATIONS

CRITERIA POLLUTANT
EMISSION CALCULATIONS

MAXIMUM HEAT INPUT:

COMPRESSOR ENGINE:

Engine No. 2005:

Fuel Heating Value	=	1,040 Btu/cf
Engine Rating	=	4,000 bhp
Brake Specific Fuel Consumption (max.)	=	7,650 Btu/bhp-hr
Brake Specific Fuel Consumption (nominal)	=	6,950 Btu/bhp-hr
Maximum Heat Input = MMBtu/Hr	=	(Btu/bhp-hr * hp)/10^6
	=	(7,650 * 4,000)/10^6
	=	30.6 MMBtu/hr

POLLUTANT EMISSION FACTORS:

COMPRESSOR ENGINE:

Engine No. 2005:

NORMAL OPERATION:

NO_x:	2.00 grams/bhp-hr	Manufacturer's Data
CO:	2.10 grams/bhp-hr	Manufacturer's Data
NMHC:	0.60 grams/bhp-hr	Manufacturer's Data
SO_2:	10 grains/100 CF	Contract Limit on Sulfur Content

lb/SO_2/hr = 10 grains/100 CF* 1 lb/7,000 grains * Btu/bhp-hr * bhp * 1 CF/1,040 Btu * 64 lb SO_2/32 lb S

= 10 grains/100CF * 1 lb/7,000 grains * 6,950 Btu/bhp-hr * 4,000 bhp * 1 CF/1,040 Btu * 64 lb SO_2/32 lb S

	=	0.76 lb SO_2/hr
grams/bhp-hr	=	lb SO_2/hr * 453.6 g * 1/bhp
	=	0.76 lb SO_2/hr * 453.6 g * 1/4,000 bhp
	=	0.086 grams/bhp-hr

PM:	5 lbs/10^6 CF	Table 1.4-1, AP-42
lb PM/hr	= 5 lb PM/10^6 CF * CF/hr	
	= 5 lb PM/10^6 CF * 0.0267 MMCF/hr	
	= 0.13 lb PM/hr	
grams/bhp-hr	= lb PM/hr * 453.6 g/1 lb * 1/bhp	
	= 0.13 lb PM/hr * 453.6 g/lb * 1/4,000 bhp	
	= 0.015 grams/bhp-hr	

WORST CASE:

NO_x:	6.00 grams/bhp-hr	Manufacturer's Data
CO:	3.00 grams/bhp-hr	Manufacturer's Data
NMHC:	1.40 grams/bhp-hr	Manufacturer's Data
SO_2:	10 grains/100 CF	Contract Limit on Sulfur Content

lb/SO_2/hr	=	10 grains/100 CF* 1 lb/7,000 grains * Btu/bhp-hr * bhp * 1 CF/1,040 Btu * 64 lb SO_2/32 lb S
	=	10 grains/100CF * 1 lb/7,000 grains * 7,650 Btu/bhp-hr * 4,000 bhp * 1 CF/1,040 Btu * 64 lb SO_2/32 lb S
	=	0.84 lb SO_2/hr
grams/bhp-hr	=	lb SO_2/hr * 453.6 g * 1/bhp
	=	0.84 lb SO^2/hr * 453.6 g/lb * 1/4,000 bhp
	=	0.095 grams/bhp-hr

PM:	5 lb/10^6 CF	Table 1.4-1, AP-42
lb PM/hr	= 5 lb PM/10^6 CF * CF/hr	
	= 5 lb PM/10^6 CF * 0.0294 MMCF/hr	
	= 0.15 lb PM/hr	
grams/bhp-hr	= lb PM/hr * 453.6 g/1 lb * 1/bhp	
	= 0.15 lb SO_2/hr * 453.6 g/lb * 1/4,000 bhp	
	= 0.017 grams/bhp-hr	

HOURS OF OPERATION:

The compressor engines are analyzed as if they have a potential to operate 8,760 hours per year.

NO_x EMISSIONS

COMPRESSOR ENGINE

Engine No. 2005:

NORMAL OPERATION:

lb NO_x/hr = (grams/bhp-hr) * (0.002205 lb/gram) * (bhp)

= (2.00 grams/bhp-hr) * (0.002205 lb/gram) * (4000 bhp)

= 17.64 lb/hour

tons NO_x/yr = (lb NO_x/hr) * (8760 hr/yr) / (2000 lb/ton)

= (17.64 lb/hr) * (8760 hr/yr) / (2000 lb/ton)

= 77.26 tons/year

WORST CASE:

lb NO_x/hr = (grams/bhp-hr) * (0.002205 lb/gram) * (bhp)

= (6.00 grams/bhp-hr) * (0.002205 lb/gram) * (4000 bhp)

= 52.92 lb/hour

EMISSION SUMMARY:

NORMAL OPERATION:

lb NO_x/hr = 17.64 lb NO_x/hr

tons NO_x/yr = 77.26 TPY NO_x

WORST CASE:

lb NO_x/hr = 52.92

CO EMISSIONS

COMPRESSOR ENGINE

Engine No. 2005:

NORMAL OPERATION:

lb CO/hr = (grams/bhp-hr) * (0.002205 lb/gram) * (bhp)

= (2.10 grams/bhp-hr) * (0.002205 lb/gram) * (4000 bhp)

= 18.52 lb/hour

tons CO/yr = (lb CO/hr) * (8760 hr/yr) / (2000 lb/ton)

= (18.52 lb/hr) * (8760 hr/yr) / (2000 lb/ton)

= 81.12 tons/year

WORST CASE:

lb CO/hr = (grams/bhp-hr) * (0.002205 lb/gram) * (bhp)

= (3.00 grams/bhp-hr) * (0.002205 lb/gram) * (4000 bhp)

= 26.46 lb/hour

EMISSION SUMMARY:

NORMAL OPERATION:

lb CO/hr = 18.52 lb CO/hr

tons CO/yr = 81.12 TPY CO

WORST CASE:

lb CO/hr = 26.46 lb CO/hr

NMHC EMISSIONS

COMPRESSOR ENGINE

Engine No. 2005:

NORMAL OPERATION:

lb NMHC/hr = (grams/bhp-hr) * (0.002205 lb/gram) * (bhp)

= (0.60 grams/bhp-hr) * (0.002205 lb/gram) * (4000 bhp)

= 5.29 lb/hour

tons NMHC/yr = (lb NMHC/hr) * (8760 hr/yr) / (2000 lb/ton)

= (8.82 lb/hr) * (8760 hr/yr) / (2000 lb/ton)

= 23.18 tons/year

WORST CASE:

lb NMHC/hr = (grams/bhp-hr) * (0.002205 lb/gram) * (bhp)

= (1.40 grams/bhp-hr) * (0.002205 lb/gram) * (4000 bhp)

= 12.35 lb NMHC/hour

EMISSIONS SUMMARY:

NORMAL OPERATION:

lb NMHC/hr = 8.82 lb NMHC/hr

tons NMHC/yr = 23.18 TPY NMHC

WORST CASE:

lb NMHC = 12.35 lb NMHC/hr

SO_2 EMISSIONS

COMPRESSOR ENGINE

Engine No. 2005:

NORMAL OPERATION:

lb SO_2/hr = (grams/bhp-hr) * (0.002205 lb/gram) * (bhp)

= (0.086 grams/bhp-hr) * (0.002205 lb/gram) * (4000 bhp)

= 0.76 lb/hour

tons SO_2/yr = (lb SO_2/hr) * (8760 hr/yr) / (2000 lb/ton)

= (0.76 lb/hr) * (8760 hr/yr) / (2000 lb/ton)

= 3.33 tons/year

WORST CASE:

lb/SO_2/hr = (grams/bhp-hr) * (0.002205 lb/gram) * (bhp)

= (0.095 grams/bhp-hr) * (0.002205 lb/gram * (4000 bhp)

= 0.84 lb/hr

EMISSIONS SUMMARY:

NORMAL OPERATION:

lb SO_2/hr = 0.76 lb SO_2/hr

tons SO_2/yr = 3.33 TPY SO_2

WORST CASE:

lb/SO_2/hr = 0.84 lb SO_2/hr

PM EMISSIONS

COMPRESSOR ENGINE

Engine No. 2005:

NORMAL OPERATION:

lb PM/hr = (grams/bhp-hr) * (0.002205 lb/gram) * (bhp)

= (0.015 grams/bhp-hr) * (0.002205 lb/gram) * (4000 bhp)

= 0.13 lb/hour/engine

tons PM/yr = (lb PM/hr) * (8760 hr/yr) / (2000 lb/ton)

= (0.13 lb/hr) * (8760 hr/yr) / (2000 lb/ton)

= 0.57 tons/year

WORST CASE:

lb PM/hr = (grams/bhp-hr) * (0.002205 lb/gram) * (bhp)

= (0.017 grams/bhp-hr) * (0.002205 lb/gram) * (4000 bhp)

= 0.15 lb/hr

EMISSION SUMMARY:

NORMAL OPERATION:

lb PM/hr = 0.13 lb PM/hr

tons PM/yr = 0.57 TPY PM

WORST CASE:

lb PM/hr = 0.15 lb PM/hr

CRITERIA POLLUTANT
EMISSION CALCULATIONS

MAXIMUM HEAT INPUT:

EMERGENCY ELECTRICAL GENERATOR:

Generator No. 2011:

Fuel Heating Value	=	1040 Btu/cf
Engine Rating	=	625 bhp
Brake Specific Fuel Consumption	=	8,387 Btu/bhp-hr
Maximum Heat Input = MMBtu/Hr	=	(Btu/bhp-hr * hp)/10^6
	=	(8,387 * 625)/10^6
	=	5.24 MMBtu/hr
Gas Consumption	=	(5.24 MMBtu/hr/1040 Btu/scf)
	=	0.005 MMscf/hr

POLLUTANT EMISSION FACTORS:

EMERGENCY ELECTRICAL GENERATOR:

Generator No. 2011:

Without Catalytic Silencer

NO_x:	9.8 grams/bhp-hr	Manufacturer's Data
CO:	10.7 grams/bhp-hr	Manufacturer's Data
HC:	0.8 grams/bhp-hr	Manufacturer's Data
NMHC:	0.08 grams/bhp-hr	(10 % of HC)
SO_2:	10 grains/100 CF	Contract Limit on Sulfur Content
	0.10 grams/bhp-hr	

lbSO_2/hr	=	10 grains/100 CF * 1 lb/7,000 grams * Btu/bhp-hr
		* bhp * CF/1,040 Btu * 64 lb SO_2/32 lb
	=	10 grains/100 CF * 1 lb/7,000 grains * 8,387 Btu/bhp-hr
		* 625 bhp * CF/1,040 Btu * 64 lb SO_2/32 lb
	=	0.144 lb SO_2/hr
grams/bhp-hr	=	lb SO_2/hr * 453.6 g/1 lb/bhp
	=	0.144 lb SO_2/hr * 453.6 g/1 lb/625 bhp
	=	0.10 grams/bhp-hr

PM:	5 lbs/10^6 CF	Table 1.4-1, AP-42
lb PM/hr	=	5 lb PM/10^6 CF * CF/hr
	=	5 lb PM/10^6 CF * 0.005 MMCF/hr
	=	0.025 lb PM/hr
grams/bhp-hr	=	lb PM/hr * 453.6 g/1 lb/bhp
	=	0.025 lb PM/hr * 453.6 g/lb/625 bhp
	=	0.018 grams/bhp-hr

With Catalytic Silencer

NO_x:	0.98 grams/bhp-hr	(10% of NO_x W/O Catalytic Silencer)
CO:	2.14 grams/bhp-hr	(20% of CO W/O Catalytic Silencer)
NMHC:	0.04 grams/bhp-hr	(50% of NMHC W/O Catalytic Silencer)
SO_2:	0.10 grains/100 CF	(100% of SO_2 W/O Catalytic Silencer)
PM:	0.018 grams/bhp-hr	(100% of PM W/O Catalytic Silencer)

HOURS OF OPERATION:

The generator will operate a maximum of 400 hours per year.

NO_x EMISSIONS

EMERGENCY ELECTRICAL GENERATOR

Generator No. 2011:

lb NO_x/hr = (grams/bhp-hr) * (0.002205 lb/gram) * (bhp)

= (0.98 grams/bhp-hr) * (0.002205 lb/gram) * (625 bhp)

= 1.35 lb/hour

tons NO_x/yr = (lb NO_x/hr) * (400 hr/yr) / (2000 lb/ton)

= (1.35 lb/hr) * (400 hr/yr) / (2000 lb/ton)

= 0.27 tons/year

CO EMISSIONS

EMERGENCY ELECTRICAL GENERATOR

Generator No. 2011:

lb CO/hr	=	(grams/bhp-hr) * (0.002205 lb/gram) * (bhp)
	=	(2.14 grams/bhp-hr) * (0.002205 lb/gram) * (625 bhp)
	=	2.95 lb/hour
tons CO/yr	=	(lb CO/hr) * (400 hr/yr) / (2000 lb/ton)
	=	(2.95 lb/hr) * (400 hr/yr) / (2000 lb/ton)
	=	0.59 tons/year

NMHC EMISSIONS

EMERGENCY ELECTRICAL GENERATOR

Generator No. 2011:

lb NMHC/hr	=	(grams/bhp-hr) * (0.002205 lb/gram) * (bhp)
	=	(0.04 grams/bhp-hr) * (0.002205 lb/gram) * (625 bhp)
	=	0.055 lb/hour
tons NMHC/yr	=	(lb NMHC/hr) * (400 hr/yr) / (2000 lb/ton)
	=	(0.055 lb/hr) * (400 hr/yr) / (2000 lb/ton)
	=	0.011 tons/year

SO_2 EMISSIONS

EMERGENCY ELECTRICAL GENERATOR

Generator No. 2011:

lb SO_2/hr	=	(grams/bhp-hr) * (0.002205 lb/gram) * (bhp)
	=	(0.10 grams/bhp-hr) * (0.002205 lb/gram) * (625 bhp)
	=	0.14 lb/hour
tons SO_2/yr	=	(lb SO_2/hr) * (400 hr/yr) / (2000 lb/ton)
	=	(0.14 lb/hr) * (400 hr/yr) / (2000 lb/ton)
	=	0.028 tons/year

PM EMISSIONS

EMERGENCY ELECTRICAL GENERATOR

Generator No. 2011:

lb PM/hr	=	(grams/bhp-hr) * (0.002205 lb/gram) * (bhp)
	=	(0.018 grams/bhp-hr) * (0.002205 lb/gram) * (625 bhp)
	=	0.025 lbs/hour
tons PM/yr	=	(lb PM/hr) * (400 hr/yr) / (2000 lb/ton)
	=	(0.025 lb/hr) * (400 hr/yr) / (2000 lb/ton)
	=	0.005 tons/year

APPENDIX E

FDER REGULATORY REQUIREMENTS SUMMARY

AIR QUALITY
REGULATORY REQUIREMENTS CHECKLIST
FLORIDA

Rules and Regulations	Applicability	Name	Comments
Title 17		Rules and Regulations of the State of Florida	Heading. No specific regulatory requirements.
• Chapter 17-2		Air Pollution	Heading. No specific regulatory requirements.
• Part I		Definitions	Heading. No specific regulatory requirements.
§17-2.100	Yes	Definitions	This subsection defines the terms used in Chapter 17-2. No specific regulatory requirements.
• Part II		General Provisions	Heading. No specific regulatory requirements.
§17-2.200	Yes	Statement of Intent	Chapter 17-2 is promulgated to eliminate, prevent, and control air pollution, except from outdoor burning and outdoor heating devices which are regulated under Chapter 17-5. It also furthers the Department of Environmental Regulation's (DER's) Prevention of Significant Deterioration (PSD) policy, and establishes ambient air quality standards and emission standards. No specific regulatory requirements.
§17-2.210	Yes	Permits Required	Unless exempt, all sources at the compressor station which emit or can reasonably be expected to emit any air pollutant are required to be permitted prior to

Rules and Regulations	Applicability	Name	Comments
			construction, modification, or initial or continued operation. FGTC must file a construction permit for new sources or those desiring to undergo modification. The permit term will be for a time period sufficient to allow determination of compliance. An operation permit is required of the source after the construction permit expires. The permit specifies the manner, nature, volume and frequency of emission permitted, applicable limiting standard (if any), proper operation and maintenance of pollution control equipment, and a term of 5 years. Requirements for sources which have shut down and desire to reactivate are specified. Exemptions to Chapter 17-2 are listed including emergency electrical generators operating $\leq$400 hrs/yr.
§17-2.215	No	Emission Estimates	Standards for making emissions estimates for all regulatory purposes including permitting and reporting purposes are established. Since standards have only been established for solid sulfur storage and handling facilities, this section is not applicable to the compressor station.
§17-2.220	Yes	Public Notice and Comment	Public notice must be provided by FGTC for construction (including modifications) permit applications. There are additional public notice requirements for sources subject to New Source Review (NSR), i.e., sources located in non-attainment areas, or Prevention of Significant Deterioration (PSD), i.e., sources located in attainment

Rules and Regulations	Applicability	Name	Comments
			areas. FGTC is required to publish the public notice after it has been prepared by DER. Procedures and specifications for public notice are detailed.
§17-2.240	Yes	Circumvention	Circumvention of pollution control devices and use of improperly operating devices are prohibited. No specific regulatory requirements.
§17-2.250	Yes	Excess Emissions	Excess emissions resulting from startup, shutdown, or malfunction are allowed for ≤ 2 hours in any 24-hour period provided best operational practices to minimize emissions are used and the activity did not result from poor maintenance or operations. Fossil fuel steam generators are presented as a special case. DER must be notified by FGTC of upset emissions followed by a written report on the malfunction(s), if requested.
§17-2.260	Yes	Air Quality Models	FGTC's estimates of concentrations of ambient air pollutants are to be based on applicable air quality models, data bases, and other DER approved requirements specified in USEPA's "Guidelines On Air Quality Models" (1978). Alternative models may be allowed following public comment and as justified in USEPA's "Workbook for Comparison of Air Quality Models" (1978).

Rules and Regulations	Applicability	Name	Comments
§17-2.270	Yes	Stack Height Policy	For the purpose of estimating ambient air concentrations through modeling, FGTC must use Good Engineering Practice (GEP). A required emission limitation shall not be affected by stack heights which exceed GEP or by other specified dispersion techniques. Actual stack heights are not restricted. GEP specifications and details regarding dispersion techniques are presented. The engine stack at this facility meets GEP.
§17-2.280	Yes	Severability	If any part of this rule is invalidated, all other parts remain valid. No specific regulatory requirements.
§17-2.290	Yes	Effective Date	The effective date of this rule is 11/1/81. No specific regulatory requirements.
• Part III		Ambient Air Quality	Heading. No specific regulatory requirements.
§17-2.300	Yes	Ambient Air Quality Standards	Standards are established to protect human health and welfare. Violations of ambient air quality standards (AAQS) are not allowed by any source. Standards are established for SO_2 (maximum 3-hour concentration not to be exceeded more than once per year = 1,500 $\mu g/m^3$; 24-hour standard not to be exceeded more than once per year = 260 $\mu g/m^3$); for PM_{10} (24-hour average concentration not to be exceeded more than once per year = 150 $\mu g/m^3$); for CO (maximum 1-hour concentration not to be exceeded more than once per

Rules and Regulations	Applicability	Name	Comments
			year = 40 $\mu g/m^3$); for O_3 (daily maximum 1-hour concentration not to be exceeded an average of more than one day per year = 100 $\mu g/m^3$); for NO_2 (annual arithmetic mean = 100 $\mu g/m^3$); and for lead (maximum quarterly arithmetic mean = 1.5 $\mu g/m^3$). Specific instructions for determining O_3 exceedances and compliance are presented. FGTC is required to maintain AAQS.
§17-2.310	Yes	Maximum Allowable Increases (Prevention of Significant Deterioration Increments	At each point within the baseline area, any increase in pollutant concentration by the compressor station over the baseline concentration shall be limited to the amounts specified in this section. Specifications regarding averaging periods and allowable increases are presented on a pollutant-by-pollutant basis for each area designation (i.e., Class I or II). One exceedance per year above the maximum allowable increase is permitted during one averaging period in the year. The engines at this station is an existing major stationary source for at least one criteria pollutant. Therefore, the new engine is subject to preconstruction PSD review.
§17-2.320	Yes	Air Pollution Episodes	Air Pollution Episodes are defined and classified. DER is authorized to declare and terminate episodes and define affected areas. Preplanned abatement strategies prepared by FGTC may be requested by DER. Plan contents are established. Procedures for enforcing non-compliance are presented.

Rules and Regulations	Applicability	Name	Comments
§17-2.330	Yes	Air Alert	Alert level criteria are defined. Actions required of specific sources upon declaration of an alert are given. FGTC is prohibited from any form of open burning.
§17-2.340	Yes	Air Warning	Warning level criteria are defined. Actions required of specific sources upon declaration of a warning are given. FGTC is prohibited from any form of open burning and unnecessary space heating and cooling.
§17-2.350	Yes	Air Emergency	Emergency level criteria are defined. Actions required of specific sources upon declaration of an emergency are given. FGTC is prohibited from any form of open burning, any construction other than in case of an emergency, and unnecessary lighting, heating, or cooling in unoccupied structures. FGTC is required to take any action that will result in the maximum reduction of air pollutants from the compressor station.
• Part IV		Area Designation and Attainment Dates	Heading. No specific regulatory requirements.
§17-2.400	Yes	Procedures for Designation and Redesignation of Areas	All areas of the state are to be designated as non-attainment, attainment, or unclassifiable with respect to each pollutant for which an AAQS has been established. Area determinations determine emission limiting standards, new and modified source review requirements, and other air pollution control measures. All areas not designated as non-attainment are PSD areas

Rules and Regulations	Applicability	Name	Comments
			which require establishment of a baseline date. PSD areas are further classified as Class I, II, or III areas for which maximum allowable increases in SO_2 and TSP shall apply after the baseline date. FGTC must comply with these maximum allowable increases. Air Quality Maintenance Areas are former non-attainment areas which have been redesignated to attainment or unclassifiable. These areas remain subject to the emission limiting standards and permit limitations imposed upon them as non-attainment areas. Procedures for redesignation of Class I, II, and III areas and PSD areas are established.
§17-2.410	Yes	Designation of Areas Not Meeting Ambient Air Quality Standards (Non-attainment Areas)	Ozone, TSP, and SO_2 non-attainment areas within the state are designated. NO_x or PM_{10} non-attainment areas have been designated. No specific regulatory requirements.
§17-2.420	Yes	Designation of Areas Meeting Ambient Air Quality Standards (Attainment Areas)	All areas not designated as non-attainment or unclassifiable are designated as attainment areas. This compressor station is located in an attainment area for SO_2 and PM, and unclassifiable for all other criteria pollutants. No specific regulatory requirements.
§17-2.430	Yes	Designation of Areas Which Cannot Be Classified Attainment or	Unclassifiable areas in the State are designated. These are all areas not designated as attainment or non-attainment. This compressor station is located in an area

Rules and Regulations	Applicability	Name	Comments
		Non-attainment	unclassifiable for NO_x, CO, and ozone. No specific regulatory requirements.
§17-2.440	Yes	Designation of Class I, Class II, and Class III Areas	Class I areas are specifically designated. All other areas are designated as Class II areas. No Class III areas are designated. No specific regulatory requirements.
§17-2.450	Yes	Designation of Prevention of Significant Deterioration (PSD) Areas	All of the State is a PSD area for TSP and SO_2 (except for designated non-attainment areas) and has a major source baseline date of 1/6/75; a minor source baseline date of 12/27/77; and a trigger date of 8/7/77. All of the state is a PSD area for NO_2 and has a major source baseline date of 2/28/88; a minor source baseline date of 3/28/88; and a trigger date of 2/8/88 No specific regulatory requirements.
§17-2.460	Yes	Designation of Air Quality Maintenance Areas	Air Quality Maintenance Areas within the State are designated. Non-attainment areas which will automatically become air quality maintenance areas upon redesignation by USEPA as attainment are listed. No specific regulatory requirements.
• Part V		New and Modified Source Review Requirements	Heading. No specific regulatory requirements
§17-2.500	No	Prevention of Significant Deterioration	This rule applies to construction of new sources or modification of existing sources in attainment areas. Twenty-eight categories of major facilities (Table 500-1) subject

Rules and Regulations	Applicability	Name	Comments
		Non-attainment Requirements (con't)	presented in §17-2.500. Therefore, this section does not apply to the compressor station.
§17-2.530	No	Source Reclassification	A source whose operating permit has been revoked is deemed permanently shut down. A source whose permit has lapsed is deemed permanently shut down unless DER is notified within 20 days of the date of lapse and that the source intends to continue operation. The source must meet the additional requirements specified in this rule. This rule does not apply since the permit for this facility has never been revoked or has never lapsed.
§17-2.540	No	Source Specific New Source Review Requirements	This rule applies only to sulfur storage and handling facilities.
• Part VI		Emission Limiting and Performance Standards	Heading. No specific regulatory requirement.
§17-2.600	No	Specific Source Emission Limiting Standards	Emission limiting standards for specified sources are presented. This compressor station is not one of the specified sources.
§17-2.610	Yes	General Particulate Emission Limiting Standard	This rule establishes a PM standard for sources not subject to any other PM or opacity standard. The compressor station is subject to this standard since it is not subject to any other PM limiting standard. A process rate

Rules and Regulations	Applicability	Name	Comments
			standard and a 20% opacity standard is established. The rule mandates that reasonable practices be taken to prevent unconfined PM emissions.
§17-2.620	Yes	General Pollutant Emission Limiting Standard	Vapor emission control is required for storing, pumping handling, processing, loading, unloading, or using in any process or installation VOCs or organic solvents. FGTC's compressor station must not emit objectionable odors.
§17-2.630	No	Best Available Control Technology (BACT)	Because this source is subject to PSD and because BACT is a requirement under PSD NSR, the engine is subject to BACT.
§17-2.640	No	Lowest Achievable Emission Rate (LAER)	LAER is required for construction in non-attainment areas or areas of influence on non-attainment areas. Because this compressor station is located in an attainment area for all criteria pollutants, the engine is not subject to LAER.
§17-2.650	No	Reasonably Available Control Technology (RACT)	RACT for VOC control is established for sources in non-attainment areas and air quality maintenance areas, and for PM in air quality maintenance areas and areas of influence on them. Because this compressor station is located in an attainment area for all criteria pollutants, this section does not apply.

Rules and Regulations	Applicability	Name	Comments
§17-2.660	Yes	Standards of Performance for New Stationary Sources	Heading. No specific regulatory requirements.
• Subpart D	No	Standards of Performance for Fossil-Fuel Fired Steam Generators for which Construction is Commenced After August 17, 1991	This facility is not a fossil-fuel fired steam generator.
• Subpart Da	No	Standards for Performance for Electric Utility Steam Generating Units for which Construction is Commenced after September 18, 1978	This facility is not an electric utility steam generating unit.
• Subpart Db	No	Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units	This facility is not a steam generating unit.
• Subpart E	No	Standards of Performance for Incinerators	This facility is not an incinerator.
• Subpart F	No	Standards of Performance for Portland Cement Plants	This facility is not a Portland Cement Plant.
• Subpart G	No	Standards of Performance for Nitric Acid Plants	This facility is not a nitric acid plant.

Rules and Regulations	Applicability	Name	Comments
• Subpart H	No	Standards of Performance for Sulfuric Acid Plants	This facility is not a sulfuric acid plant.
• Subpart I	No	Standards of Performance for Asphalt Concrete Plants	This facility is not a hot mix asphalt facility.
• Subpart J	No	Standards of Performance for Petroleum Refineries	This facility is not a petroleum refinery.
• Subpart K	No	Standards of Performance for Storage Vessels for Petroleum Liquids Constructed after June 11, 1973, and Prior to May 19, 1978	The storage vessels at this facility do not meet the minimum criteria specified (storage capacity $\geq$40,000 gallons).
• Subpart Ka	No	Standards of Performance for Storage Vessels for Petroleum Liquids Constructed after May 18, 1978.	The storage vessels at this facility do not meet the minimum criteria specified (storage capacity $\geq$40,000 gallons).
• Subpart Kb	No	Standards of Performance for Storage Vessels for Petroleum Liquids Constructed after July 23, 1978.	The storage vessels at this facility do not meet the minimum criteria specified (storage capacity $\geq$40 m^3).
• Subpart L	No	Standards of Performance for Secondary Lead Smelters	This facility is not a lead smelter.

Rules and Regulations	Applicability	Name	Comments
• Subpart M	No	Standards of Performance for Secondary Brass and Bronze Ingot Production Plants	This facility does not produce brass or bronze.
• Subpart N	No	Standards of Performance for Iron and Steel Plants	This facility is not an iron or steel plant.
• Subpart Na	No	Standards of Performance for Basic Oxygen Process Steel-making Facilities for which Construction is Commenced after January 20, 1983	This facility is not a steelmaking facility.
• Subpart O	No	Standards of Performance for Sewage Treatment Plants	This facility is not a sewage treatment plant.
• Subpart P	No	Standards of Performance for Primary Copper Smelters	This facility is not a copper smelter.
• Subpart Q	No	Standards of Performance for Primary Zinc Smelters	This facility is not a zinc smelter.
• Subpart R	No	Standards of Performance for Primary Lead Smelters	This facility is not a lead smelter.
• Subpart S	No	Standards of Performance for Primary Aluminum Reduction Plants	This facility is not an aluminum reduction plant.

Rules and Regulations	Applicability	Name	Comments
• Subpart T	No	Standards of Performance for Phosphate Fertilizer Industry (P.F.I.)s: Wet Process Phosphoric Acid Plants	This facility is not part of the phosphate fertilizer industry.
• Subpart U	No	Standards of Performance for P.F.I.s: Superphosphoric Acid Acid Plants	This facility is not part of the phosphate fertilizer industry.
• Subpart V	No	Standards of Performance for P.F.I.s: Diammonium Phosphate Plants	This facility is not part of the phosphate fertilizer industry.
• Subpart W	No	Standards of Performance for P.F.I.s: Triple Superphosphate Plants	This facility is not part of the phosphate fertilizer industry.
• Subpart X	No	Standards of Performance for P.F.I.s: Granular Triple Superphosphate Storage Facilities	This facility is not part of the phosphate fertilizer industry.
• Subpart Y	No	Standards of Performance for Coal Preparation Plants	This facility is not a coal preparation plant.
• Subpart Z	No	Standards of Performance for Ferroalloy Production Facilities	This facility is not a ferroalloy production facility.

Rules and Regulations	Applicability	Name	Comments
• Subpart AA	No	Standards of Performance for Steel Plants: Electric Arc Furnaces Constructed after October 21, 1974, and on or before August 17, 1983	This facility is not a steel plant.
• Subpart AAa	No	Standards of Performance for Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels Constructed after August 7, 1983	This facility is not a furnace.
• Subpart BB	No	Standards of Performance for Kraft Pulp Mills	This facility is not a Kraft pulp mill.
• Subpart CC	No	Standards of Performance for Glass Manufacturing Plants	This facility is not a glass manufacturing plant.
• Subpart DD	No	Standards of Performance for Grain Elevators	This facility is not a grain elevator.
• Subpart EE	No	Standards of Performance for Surface Coating: Metal Furniture	This facility is not involved in surface coating operations.
• Subpart GG	No	Standards of Performance for Stationary Gas Turbines	The engine to be installed at Compressor Station No. 20 is not a turbine engine.

Rules and Regulations	Applicability	Name	Comments
• Subpart HH	No	Standards of Performance for Lime Manufacturing Plants	This facility is not a lime manufacturing plant.
• Subpart KK	No	Standards of Performance for Lead-Acid Battery Manufacture Plants	This facility is not a lead-acid battery manufacturing plant.
• Subpart LL	No	Standards of Performance for Metallic-Mineral Processing Plants	This facility is not a metallic-mineral processing plant.
• Subpart MM	No	Standards of Performance for Automobile and Light Duty Truck Surface Coating Operations	This facility is not a surface coating facility.
• Subpart NN	No	Standards of Performance for Phosphate Rock Plants	This facility is not a phosphate rock plant.
• Subpart PP	No	Standards of Performance for Ammonium Sulfate Manufacturing	This facility is not involved in the manufacture of ammonium sulfate.
• Subpart QQ	No	Standards of Performance for Graphic Arts Industry: Publication Rotogravure Printing	This facility is not part of the graphic arts industry.

Rules and Regulations	Applicability	Name	Comments
• Subpart RR	No	Standards of Performance for Pressure Sensitive Tape and Label Surface Coating Operations	This facility is not involved in coating operations.
• Subpart SS	No	Standards of Performance for Industrial Surface Coating: Large Appliances	This facility is not involved in coating operations.
• Subpart TT	No	Standards of Performance for Metal Coil Surface Coating	This facility is not involved in coating operations.
• Subpart UU	No	Standards of Performance for Asphalt Processing and Asphalt Roofing Manufacture	This facility is not involved in asphalt processing or asphalt roofing manufacture.
• Subpart VV	No	Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry	This facility is not a SOCMI facility.
• Subpart WW	No	Standards of Performance for the Beverage Can Surface Coating Industry	This facility is not involved in coating operations.
• Subpart XX	No	Standards of Performance for Bulk Gasoline Terminals	This facility is not a bulk gasoline terminal.

Rules and Regulations	Applicability	Name	Comments
• Subpart AAA	No	Standards of Performance for New Residential Wood Heaters	This facility is not a residential wood heater.
• Subpart BBB		Standards of Performance for the Rubber Tire Manufacturing Industry	This facility is not involved in the manufacture of rubber tires.
• Subpart FFF	No	Standards of Performance for Flexible Vinyl and Urethane Coating and Printing	This facility is not involved in coating or printing.
• Subpart GGG	No	Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries	This facility is not a petroleum refinery.
• Subpart HHH	No	Standards of Performance for Synthetic Fiber Production Facilities	This facility is not a synthetic fiber production facility.
• Subpart III	No	Standards of Performance for Volatile Organic Compound (VOC) Emissions from the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Air Oxidation Unit Processes	This facility is not a SOCMI facility.
• Subpart JJJ	No	Standards of Performance for Petroleum Dry Cleaners	This facility is not a petroleum dry cleaner.

Rules and Regulations	Applicability	Name	Comments
• Subpart KKK	No	Standards of Performance for Equipment Leaks of VOC from Onshore Natural Gas Processing Plants	This facility is not a natural gas processing plant.
• Subpart LLL	No	Standards of Performance for Onshore Natural Gas Processing: SO_2 Emissions	This facility is not a natural gas processing plant.
• Subpart NNN	No	Standards of Performance for Volatile Organic Compound (VOC) Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations	This facility is not a SOCMI facility.
• Subpart OOO	No	Standards of Performance for Nonmetallic Mineral Processing Plants	This facility is not a nonmetallic mineral processing plant.
• Subpart PPP	No	Standards of Performance for Wool Fiberglass Insulation Manufacturing Plants	This facility is not a wool fiberglass manufacturing plant.
• Subpart QQQ	No	Standards of Performance for Petroleum Wastewater Systems	This facility is not a petroleum wastewater system.

Rules and Regulations	Applicability	Name	Comments
• Subpart SSS	No	Standards of Performance for Magnetic Tape Manufacturing Industry	This facility is not involved in the manufacture of magnetic tape.
• Subpart TTT	No	Standards of Performance for Industrial Surface Coating: Surface Coating of Plastic Parts for Business Machines	This facility is not a surface coating facility.
• Subpart VVV	No	Standards of Performance for Polymeric Coating of Supporting Substrates Facilities	This facility is not involved in coating operations.
§17-2.670	No	National Emission Standards for Hazardous Air Pollutants	The federal NESHAPS are incorporated here by reference.
• Subpart B	No	Radon-222 Emission from Underground Uranium Mines	This facility is not an underground uranium mine.
• Subpart C	No	Beryllium	This facility is not a source of beryllium.
• Subpart D	No	Beryllium Rocket Motor Firing	This facility is not engaged in rocket motor firing.
• Subpart E	No	Mercury	There are no mercury emissions from this facility.
• Subpart F	No	Vinyl Chloride	There are no vinyl chloride emissions from this facility.
• Subpart G	No		Reserved. No specific regulatory requirements.

Rules and Regulations	Applicability	Name	Comments
• Subpart H	No		Reserved. No specific regulatory requirements.
• Subpart I	No		Reserved. No specific regulatory requirements.
• Subpart J	No	Benzene Equipment Leaks	There are no benzene emissions from this facility.
• Subpart K	No		Reserved. No specific regulatory requirements.
• Subpart L	No	Benzene Emissions from Coke By-Product Recovery Plants	This facility is not a coke by-product recovery plant.
• Subpart M	No	Asbestos	There are no asbestos emissions at this facility.
• Subpart N	No	Standard for Inorganic Arsenic Emissions from Glass Manufacturing Plants	This facility is not a glass manufacturing plant.
• Subpart O	No	Standard for Inorganic Arsenic Emissions from Primary Copper Smelters	This facility is not a primary copper smelter.
• Subpart P	No	Standard for Inorganic Arsenic Emissions from Arsenic Trioxide and Metallic Arsenic Production Facilities	This facility is not an arsenic production facility.
• Subpart Q	No		Reserved. No specific regulatory requirements.

Rules and Regulations	Applicability	Name	Comments
• Subpart R	No		Reserved. No specific regulatory requirements.
• Subpart S	No		Reserved. No specific regulatory requirements.
• Subpart T	No		Reserved. No specific regulatory requirements.
• Subpart U	No		Reserved. No Specific regulatory requirements.
• Subpart V	No	Equipment Leaks (Fugitive Emission Sources)	This facility will have no benzene or vinyl chloride emissions.
• Subpart W	No	Radon-222 Emissions from Licensed Uranium Mill Tailings	This facility is not a licensed uranium mill tailing.
• Subpart X	No		Reserved. No specific regulatory requirements.
• Subpart Y	No	Benzene Emissions from Benzene Storage Vessels	This facility does not have benzene storage vessels.
• Subpart Z	No		Reserved. No specific regulatory requirements.
• Subpart AA	No		Reserved. No specific regulatory requirements.
• Subpart BB	No	Benzene Emissions from Benzene Transfer Operations	There are no benzene transfer operations at this facility.
• Subpart CC	No		Reserved. No specific regulatory requirements.

Rules and Regulations	Applicability	Name	Comments
• Subpart DD	No		Reserved. No specific regulatory requirements.
• Subpart EE	No		Reserved. No specific regulatory requirements.
• Part VII	No	Source Sampling and Monitoring	Heading. No specific regulatory requirements.
§17-2.700	Yes	Stationary Point Source Emissions Test Procedures	The methods and procedures which FGTC must use to perform compliance test on stack emission are presented.
§17-2.710	No	Continuous Monitoring Requirements	These requirements apply only to certain specified sources. This facility is not one of those specified.
§17-2.753	No	DER Ambient Test Methods	These requirements apply only to certain specified sources. This facility is not one of those specified.
• Part VIII	Yes	Local Air Pollution Control Programs	This part establishes local air pollution control programs. in specified counties. This facility is not located in one of the counties with approved programs.
• Part IX	No	Compliance Schedules	This part applies only to certain specified sources. This facility is not one of the sources specified.
• Chapter 17-4		Permits	Heading. No specific regulatory requirements.
§17-4.001	No	Scope of Part I	This section establishes that procedures for obtaining an FDER permit will be presented in Part I. No specific regulatory requirements.

Rules and Regulations	Applicability	Name	Comments
§17-4.020	Yes	Definitions	Definitions of terms used in Part I to which FGTC is subject are presented.
§17-4.021	No	Transferability of Definitions	Terms defined in other Chapters retain their meaning here, unless otherwise defined. No specific regulatory requirements.
§17-4.022	No	Determination of the Land-ward Extent of Surface Waters of the State	Transferred to §17-3.022. No specific regulatory require-ments.
§17-4.030	Yes	General Prohibition	All FGTC stationary sources must have a valid permit unless exempted, and must be constructed, maintained, and operated consistent with the terms of the permit.
§17-4.040	Yes	Exemptions	DER may exempt structural changes which will not change quality, nature, or quantity of emissions or will not cause pollution. DER may exempt sources which do not contribute significantly to pollution problems within the state. FGTC may request an exemption for sources which meet the previously stated conditions.
§17-4.050	Yes	Procedure to Obtain Permit: Application	FGTC is to complete an application in quadruplicate on DER forms. The application must be certified by a Florida Registered Professional Engineer and must be accompanied by the appropriate processing fee. FGTC must submit a certification of construction and permit fee

Rules and Regulations	Applicability	Name	Comments
			upon completion of construction in order to be granted an operation permit.
§17-4.055	Yes	Permit Processing	This section establishes the schedule which DER must follow in processing the permit application. DER may request additional information from FGTC. FGTC may request a hearing if it believes that the requested information is not legally authorized.
§17-4.060	Yes	Consultation	FGTC or their representatives are encouraged to consult with DER prior to submitting the permit application. No specific regulatory requirements.
§17-4.070	Yes	Standards for Issuing or Denying Permits; Issuance; Denial	The construction permit will be issued "for a period of time as necessary." The operation permit will have a 5 year term. FGTC's compliance history will be considered in issuing/denying the application. DER will stipulate permit conditions. No specific regulatory requirements.
§17-4.080	Yes	Modification of Permit Conditions	DER may, after issuing the permit, modify or establish new permit conditions. FGTC may request a permit modification permit extension.
§17-4.090	Yes	Renewals	FGTC must apply for a permit renewal prior to 60 days before the expiration of the permit.
§17-4.100	Yes	Suspension and Revocation	FGTC's permit may be suspended or revoked for actions specified within the section.

Rules and Regulations	Applicability	Name	Comments
§17-4.110	Yes	Financial Responsibility	DER may request FGTC to submit proof of financial responsibility, and may require a bond to guarantee compliance.
§17-4.120	Yes	Transfer of Permits	FGTC must submit an "Application for Transfer of Permit" within 30 days of selling/legally transferring a permitted facility.
§17-4.140	No	Reports	Repealed. No specific regulatory requirements.
§17-4.150	Yes	Review	After having received notice of a proposed or final DER action, FGTC waives its right to an administrative hearing if FGTC fails to respond to the notice with 14 days of receipt.
§17-4.160	Yes	Permit Conditions	FGTC is required to properly operate and maintain the facility in order to maintain compliance. DER may access FGTC's records, inspect the facility, and collect samples. All FGTC data may be used in enforcement proceedings. FGTC must keep a copy of the permit at the facility. All monitoring information, reports, and data used to complete applications must be retained at the site or other location specified in the permit for 3 years. FGTC is required to keep specific information regarding monitoring data.

Rules and Regulations	Applicability	Name	Comments
• Part II	No	Specific Permits: Requirements	Heading. No specific regulatory requirements.
§17-4.200	No	Scope of Part II	This section establishes that additional requirements for certain permits are established in the following sections. No specific regulatory requirements.
§17-4.210	Yes	Construction Permits	FGTC is required to apply on DER forms for a permit to construct.
§17-4.220	Yes	Operation Permit for New Sources	FGTC is required to submit the appropriate fee and certification that construction was completed.
§17-4.230	No	Operation Permits for Pollution Sources	Repealed. No specific regulation requirements.
§17-4.240	No	Operation Permits for Water Pollution Sources	This facility is not a water pollution source.
§17-4.242	No	Antidegradation Permitting Requirements; Outstanding Florida Waters; Outstanding National Resource Waters; Equitable Abatement	This facility is not a water pollution source.
§17-4.243	No	Exemption from Water Quality Criteria	This facility is not a water pollution source.

Rules and Regulations	Applicability	Name	Comments
§17-4.244	No	Mixing Zones; Surface Waters	This facility is not a water pollution source.
§17-4.245	No	Installations Discharging to Ground Water; Permitting and Monitoring Requirements	Transferred to §17-28.700. This facility is not a water pollution source.
§17-4.246	No	Sampling and Testing Methods	This facility is not a water pollution source.
§17-4.247	No	Pollution Surveys	Transferred to §17-19.090. This facility is not a water pollution source.
§17-4.248	No	Stormwater	Repealed. No specific regulatory requirements.
§17-4.250	No	Water Pollution Temporary Operation Permits; Conditions	This facility is not a water pollution source.
§17-4.260	No	Permits Required for Sewage	Repealed. No specific regulatory requirements.
§17-4.270	No	Drainage Wells; Permits	Deleted. No specific regulatory requirements.
§17-4.280	No	Dredging or Filling Activities; Permits, Certifications	Transferred to §17-12.150. This facility is not engaged in dredge/fill operations.
§17-4.290	No	Construction, Dredging, or Filling in, or over Navigable Waters; Permits Required Pursuant to Chapter 253, F.S.	Transferred to §17-12.160. This facility is not engaged in dredge/fill operations.

Rules and Regulations	Applicability	Name	Comments
• Part III	No	Procedures for General Permits	This facility does not meet the requirements for being issued a general permit.
• Chapter 17-256	No	Open Burning and Frost Protection Fires	This facility will not be engaged in open burning or use of frost protection fires.
• Chapter 17-8	Yes	Ad Valorem Tax Assessment Rules	A tax assessor may require FGTC to submit a detailed list of pollution control devices at the facility, and their cost and function, for the purpose of assessing ad valorem taxes.
• Chapter 17-242	No	Mobile Source - Motor Vehicle Emission Standards and Test Procedures	This facility is not involved with compliance and testing of mobile sources/motor vehicles.
• Chapter 17-243	No	Tampering With Motor Vehicle Air Pollution Control Equipment	This facility is not involved with checking motor vehicle pollution control devices for tampering.