Duke Energy North America
A Duke Energy Company

Duke Energy
North America, LLC
5400 Westheimer Court
Houston, TX 77056-5310
P.O. Box 1642
Houston, TX 77251-1642
(713) 627-6500

October 3, 2000

Via: FEDERAL EXPRESS

Ms. Patty Adams
Florida Department of Environmental Protection
111 South Magnolia, Suite 4
Tallahassee, Fl 32301

Dear Ms. Adams:

Enclosed please find a check for the Air Permit Application for the Duke Energy Ft. Pierce, LLC Facility.

Please contact me at 713/627-5644 should you have any questions.

Sincerely,

Nathan K. Plagens

Nathan K. Plagens
Manager, Environmental Services

cc: D. Runyan

APPLICATION FOR

Permit to Construct and Operate Air Emissions Equipment

for

Duke Energy Fort Pierce, LLC
Duke Energy Fort Pierce Generating Station
Fort Pierce, Florida

Prepared for

Duke Energy Fort Pierce, LLC

Prepared by

CH2MHILL

115 Perimeter Center Place, Suite 700
Atlanta, Georgia 30346

September 2000

CH2MHILL

CH2M HILL
115 Perimeter Center Place NE
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Atlanta, GA
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September 20, 2000

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Mr. A. A. Linero, P.E.
Administrator, New Source Review Section
Florida Department of Environmental Protection
Division of Air Resources Management
111 South Magnolia, Suite 4
Tallahassee, FL 32301

Subject: Application for Permit To Construct
Duke Energy Fort Pierce Generating Station
Fort Pierce, Florida

Dear Mr. Linero:

Enclosed please find six copies of the Application for a Permit to Construct the proposed Duke Energy Fort Pierce Generating Station to be located near Fort Pierce, Florida. This application is being submitted on behalf of our client, Duke Energy North America and we ask that your office review this document and initiate the permitting process.

We very much appreciate the cooperation and assistance provided you and your staff at FDEP during the course of the preparation of this application. If you should have any questions regarding this submittal, please do not hesitate to call Nathan Plagans at Duke Energy North America at (713)-627-5985, or the undersigned at (770) 604-9182, ext 355.

Sincerely,

CH2M HILL

George Howroyd

George Howroyd, Ph.D., P.E.
Principal Engineer

ATL\14648 Duke Florida\App Cover Letter.doc
c: Nathan Plagens/DENA

Application for Permit to Construct and Operate Air Emissions Equipment

for

Duke Energy Fort Pierce, LLC
Duke Energy Fort Pierce Generating Station
Fort Pierce, Florida

Prepared for

Duke Energy Fort Pierce, LLC

September 2000

CH2MHILL
115 Perimeter Center Place, Suite 700
Atlanta, Georgia 30346

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Acronyms

ABB	Asea Brown Boveri
BACT	Best Available Control Technology
CARB	California Air Resources Board
CO	Carbon Monoxide
CFR	Code of Federal Regulations
CH_4	Methane
CRF	Capital Recovery Factor
CT	Combustion Turbine
CTG	Combustion Turbine Generator
DLN	Dry Low NO_X
ESP	Electrostatic Precipitator
FAC	Florida Administrative Code
FDEP	Florida Department of Environmental Protection
GE	General Electric
GEP	Good Engineering Practice
HAP	Hazardous Air Pollutant
HRSG	Heat Recovery Steam Generator
ISC	Industrial Source Complex
KW	Kilowatts
KWh	Kilowatt per hour
LAER	Lowest Achievable Emission Rate
LHV	Lower Heating Value
LTO	Low Temperature Oxidation
MACT	Maximum Available Control Technology
MMBtu/hr	Million Btu per hour
MW	Megawatts
NAAQS	National Ambient Air Quality Standards
NH_3	Ammonia
NO_X	Nitrogen Oxides
NSPS	New Source Performance Standards
O_2	Oxygen
OAQPS	Office of Air Quality Planning and Standards
PAH	Polycyclic Aromatic Hydrocarbons

PG&E	Pacific Gas and Electric
PM	Particulate Matter
PM-10	Particulate matter less than 10 micrometers in diameter
Ppmvd	Parts per million based on dry volume
Ppmvw	Parts per million based on wet volume
POM	Polycyclic Organic Matter
PSD	Prevention of Significant Deterioration
Psia	Pounds per square inch absolute
RBLC	RACT/BACT/LAER Clearinghouse
ROI	Radius Of Impact
SARA	Superfund Amendments and Reauthorization Act
SCAQMD	South Coast Air Quality Management District
SCF	Standard Cubic Feet
SDCFH	Standard Dry Cubic Feet per Hour
SCR	Selective Catalytic Reduction
SO_2	Sulfur Dioxide
SO_3	Sulfur Trioxide
US EPA	United States Environmental Protection Agency
VOC	Volatile Organic Compound

1.0 Introduction

Duke Energy Fort Pierce, LLC (Duke) proposes to construct and operate a power generating facility near the City of Fort Pierce, Florida, in St. Lucie County. The Facility will be known as the Duke Energy Fort Pierce Generating Station, but will be referred to as "The Facility" for the purposes of this report.

The Facility will utilize eight simple cycle generating units to produce up to 640 megawatts (MW) of peak power at its design operating conditions. The primary fuel used by the turbines will be natural gas, with the capability of using low sulfur (0.05 percent) No. 2 distillate fuel oil as a backup fuel in the unlikely event of a natural gas curtailment.

Construction of the Facility is expected to commence in May 2001 with commercial operation expected by June 2002.

This permit application was prepared with the assistance of the consulting firm, CH2M HILL. Questions regarding CH2M HILL's participation can be addressed to the individuals listed below at Duke Energy North America in Houston, Texas, or CH2M HILL in Atlanta, Georgia:

Mr. Nathan K. Plagens
Manager, Environmental Services
Duke Energy North America
5400 Westheimer Court
Houston, Texas 77056-5310
Telephone (713) 627-5985
FAX (713) 627-5644
e-mail: nkplagens@duke-energy.com

Dr. George C. Howroyd, P.E
CH2M HILL
115 Perimeter Center Place, Suite 700
Atlanta, Georgia 30346
Telephone (770) 604-9182, ext. 355
FAX (770) 604-9183

e-mail: ghowroyd@ch2m.com

2.0 Facility Description

2.1 General

Facility Name:	Duke Energy Fort Pierce Generating Station
Owner:	Duke Energy Fort Pierce, LLC
Contact:	Mr. Nathan Plagens Manager, Environmental Services Duke Energy North America 5400 Westheimer Court Houston, Texas 77056-5310 Telephone (713) 627-5985 FAX (713) 627-5644

2.2 Site Description

The proposed Facility will be located on a parcel of land approximately 96-acres in size, and located approximately four miles south southwest of Fort Pierce, St. Lucie County Florida, as shown in Figure 2-1. The proposed plot plan of the facility is illustrated in Figure 2-2. Proposed power train elevations for the simple cycle generating units are illustrated in Figure 2-3.

The Facility will be constructed to generate nominally 640 MW of electricity using eight General Electric Model 7EA combustion turbines (CTs) operating in simple cycle configuration.

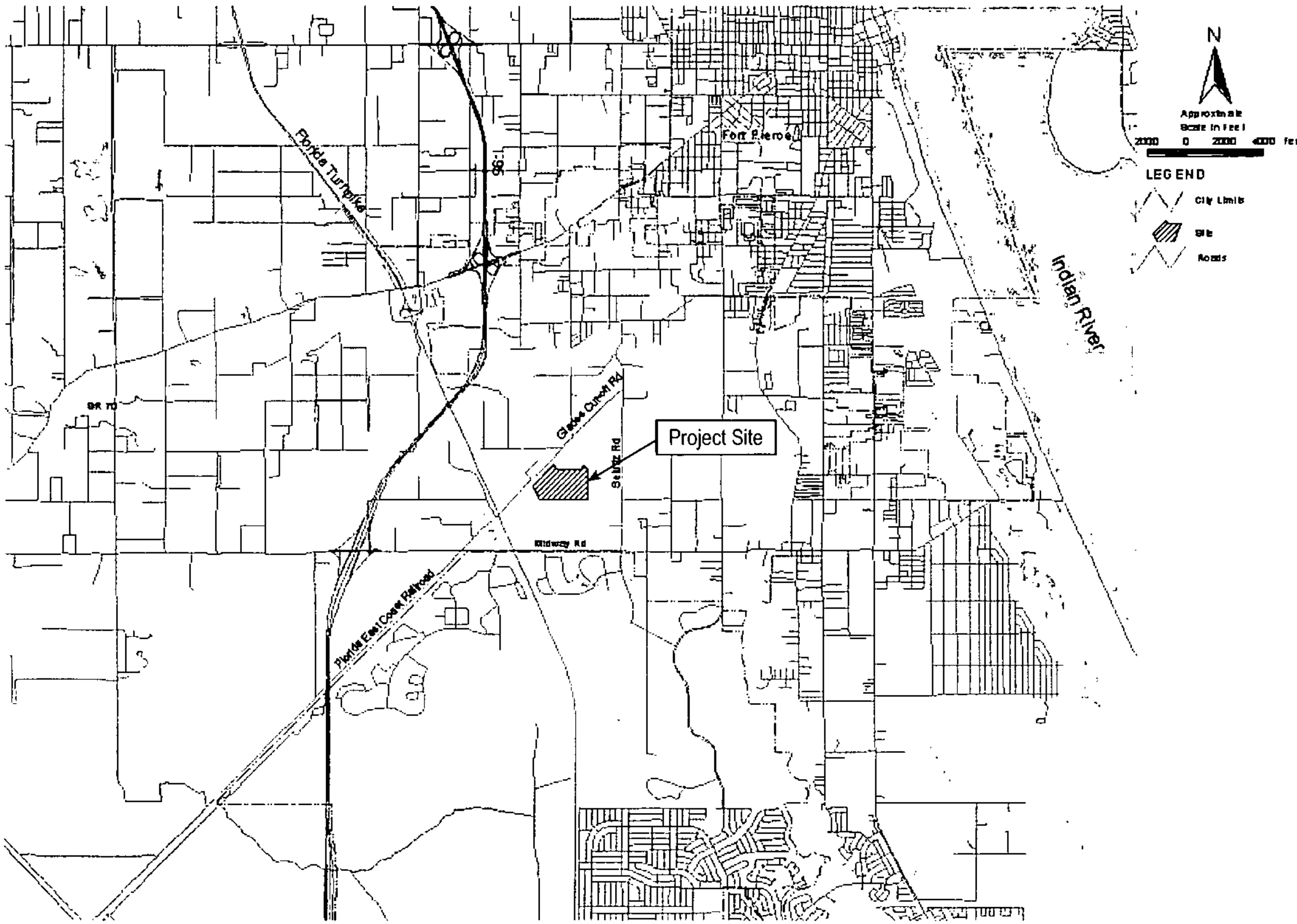

Figure 2-1
Site Location Map
Duke Energy Fort Pierce, LLC
Fort Pierce Generating Station
Fort Pierce, Florida

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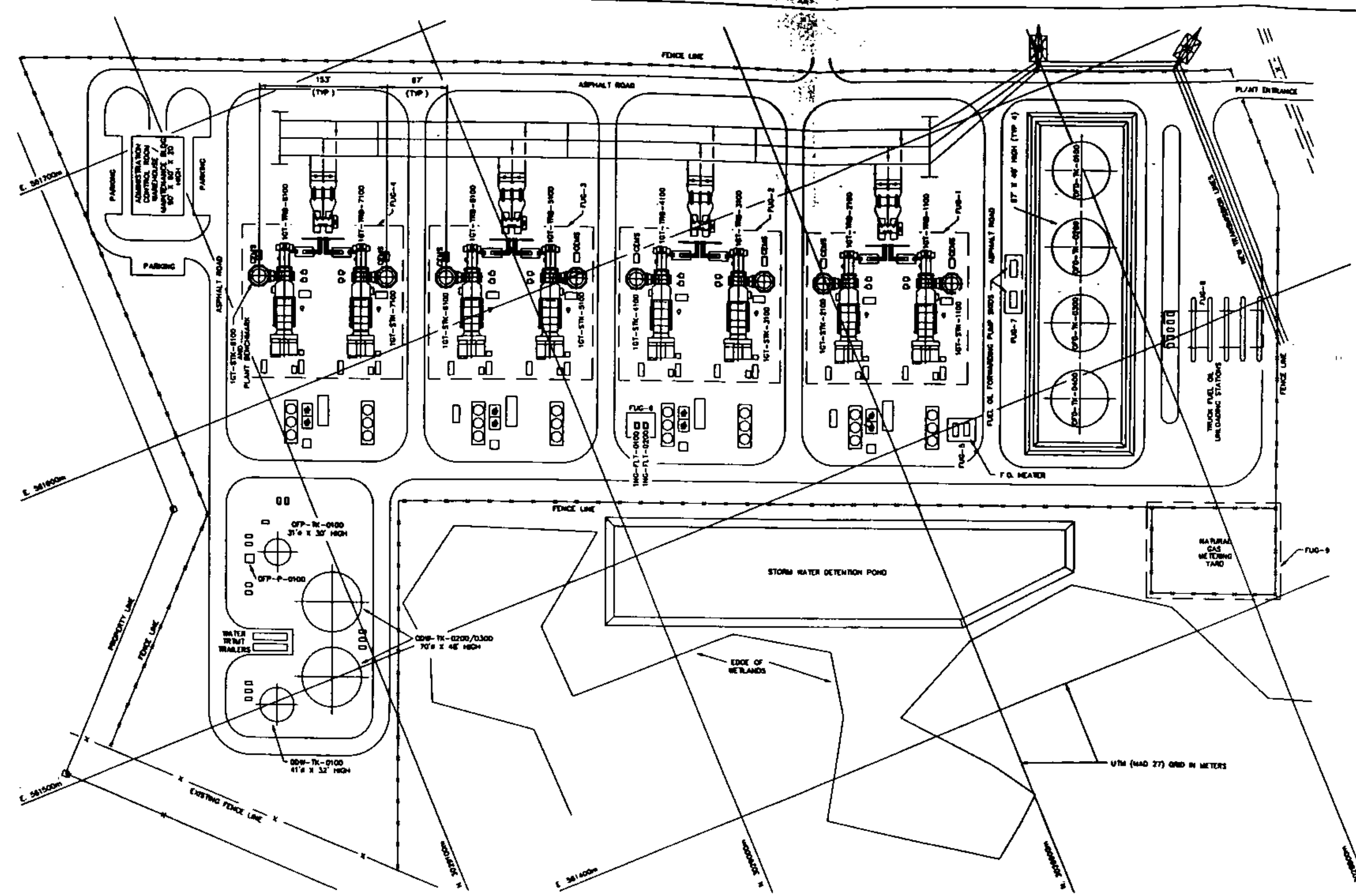

EMISSION POINT COORDINATES

DESCRIPTION	NORTHING	EASTING
0GT-STK-1100	N. 3028858m	E. 561548m
0GT-STK-2100	N. 3028901m	E. 561565m
0GT-STK-3100	N. 3028921m	E. 561573m
0GT-STK-4100	N. 3028863m	E. 561591m
0GT-STK-5100	N. 3028883m	E. 561599m
0GT-STK-6100	N. 3029025m	E. 561618m
0GT-STK-7100	N. 3029045m	E. 561623m
0GT-STK-8100	N. 3029087m	E. 561642m

EQUIPMENT LIST

1GT-TRB-1100 - 8100	COMBUSTION TURBINE GENERATOR
1GT-STK-1100 - 8100	TURBINE EXHAUST STACK
1NG-FLT-0100/0200	FUEL GAS COALESCING FILTERS
0DW-TK-0100	FOGGING WATER STORAGE TANK
0DW-TK-0200/0300	NOx WATER STORAGE TANK
0FP-TK-0100	FIRE WATER/SERVICE WATER TANK
0FP-P-0100	DIESEL FIRE WATER PUMP
0FO-TK-0100 - 0400	FUEL OIL STORAGE TANKS

NOTES

1. POST-CONSTRUCTION ELEVATION OF SITE = 17' ABOVE MSL.
2. FUG-X DENOTES FUGITIVE EMISSIONS AREAS.
3. ALL COORDINATES SHOWN ARE UTM ZONE 17 GRID, NAD27, AND ARE GIVEN IN METERS.

PRELIMINARY

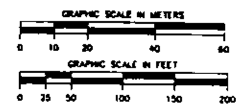

Figure 2-2
Proposed Plot Plan
Duke Energy Fort Pierce, LLC
Fort Pierce Generating Station
Fort Pierce, Florida

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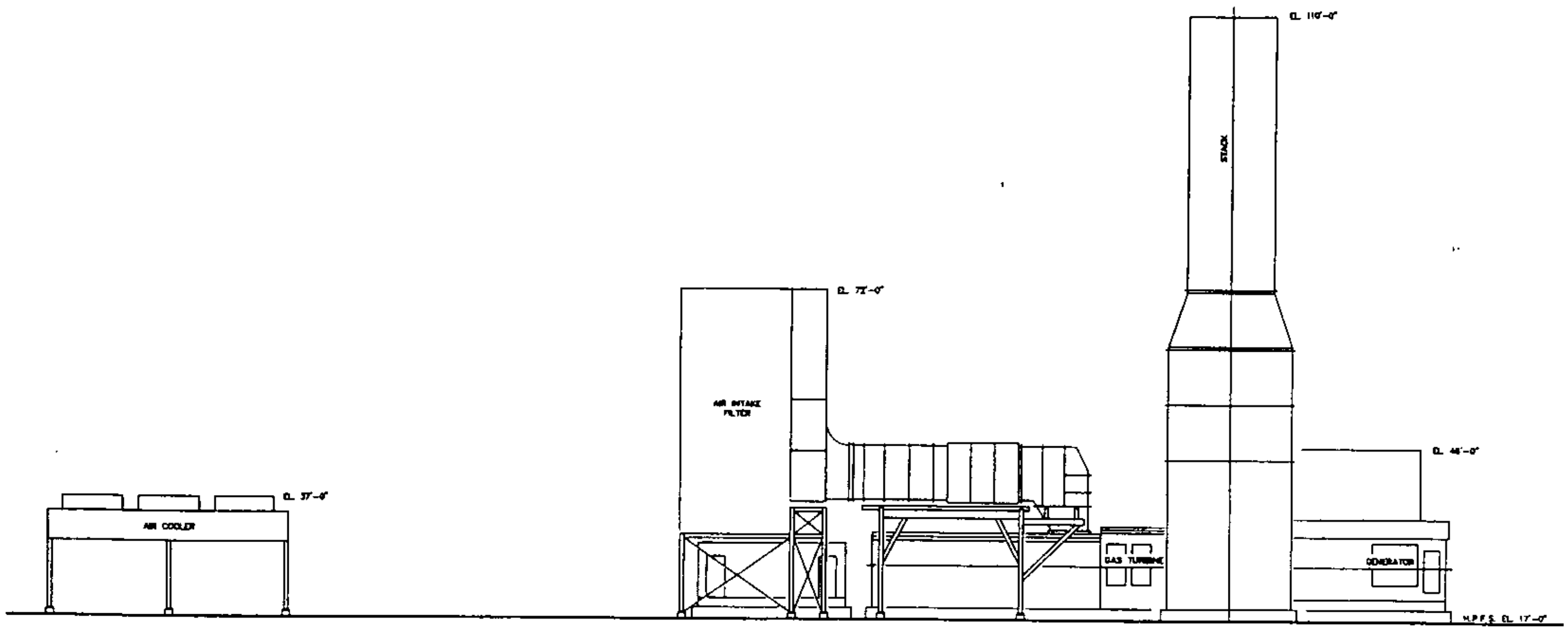

POWER TRAIN ELEVATION
VIEW LOOKING NORTH

PRELIMINARY

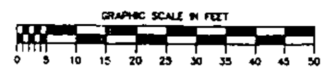

Figure 2-3
Power Train Elevation
Duke Energy Fort Pierce, LLC
Fort Pierce Generating Station
Fort Pierce, Florida

The Facility will also be designed to incorporate the following major components:

- Eight 93 foot-exhaust stacks (measured above plant grade), one for each simple-cycle combustion turbine generator (CTG) set;
- Air-cooled auxiliary cooling system;
- Various single-story buildings of approximately 6,000 to 7,000 square feet housing the control room, maintenance shop, and other support facilities;
- Outdoor electrical switchyard, including station step-up transformers, switches, and power metering equipment;
- Underground natural gas transmission line extending from an existing gas transmission line to the Facility;
- Water and wastewater treatment systems and stormwater management facilities. These services will be provided to and from the Facility via underground pipeline;
- Tanks for water and fuel oil storage, etc.;
- Paved roads and parking areas; and
- Diesel firewater pump for emergency use only.

2.3 Facility Description

The simple cycle generating units will be operated as a fully dispatchable peak power generating facility, and may operate up to 24 hours per day and up to 20,000 hours per year for all eight units combined (i.e., an average of 2,500 hours per year per unit). In the event that natural gas is not available, each turbine could operate (on average) up to 1,000 hours per year on backup fuel oil. Exclusive of short-term transient periods (i.e., such as a change in load level and periods of startup and shutdown), nitrogen oxide (NO_X) emissions from the proposed CTG exhaust will be controlled to a level of 12.0 parts per million based on dry volume (ppmvd) (corrected to 15 percent O_2) at full load using dry low-NO_X combustion technology when firing natural gas. During periods of fuel oil firing, NO_X

emissions will be controlled to a level of 42.0 ppmvd (corrected to 15 percent O_2) by using water injection to control flame temperatures in the combustor. These levels of control are consistent with what is currently considered to be Best Available Control Technology (BACT) for the industry.

The combustion turbine is the main component of a simple-cycle power system. First, air is filtered and compressed in a multiple-stage axial flow compressor. Compressed air and fuel are mixed and combusted in the turbine combustion chamber. Dry low NO_X combustors are used to minimize NO_X formation during combustion. Exhaust gas from the combustion chamber is expanded through a multi-stage power turbine that drives both the air compressor and electric power generator. Exhaust gas exits the power turbine at approximately 1,100°F and 14.69 pounds per square inch absolute (psia).

An inlet air fogging system will be provided to enhance the power output of the combustion turbine generators during the summer months of natural gas operation. The fogging system will consist of two demineralized water storage tanks, pump forwarding/injection skids for each combustion turbine generator unit, and a water treatment system to provide makeup water to the demineralized water storage tanks.

For auxiliary plant equipment, a closed loop auxiliary cooling water system will be utilized. This system will use a water/glycol mixture as the cooling medium and will include an expansion tank, pumps, and water-to-air fin fan heat exchangers.

Table 2-1 summarizes the energy consumption and production capabilities of the CTG for each of the eight CTG trains. The hourly electrical production rate is dependent on operating and ambient conditions such as CTG operating load (percent of maximum load) and ambient temperature. The production rates presented in this Table are based on maximum output of the turbine at the ambient conditions noted (i.e., the approximate mean annual average temperature).

TABLE 2-1 Summary of Energy Production Design Criteria for Simple Cycle Generating Units Duke Energy Fort Pierce, LLC Fort Pierce Generating Facility *Fort Pierce, Florida*	
General Electric Model 7EA Combustion Turbine Generator Sets	
Number of units	8
Fuel[a]	Natural Gas/Fuel Oil
Electrical Capacity (at 74.6°F, 72% RH, 14.69 psia)	
Net Electrical Capacity (one CTG, with Inlet Fogger on)	81,360 kW (Natural Gas)[b]
Net Electrical Capacity (one CTG, Water Injection)	81,910 kW (Fuel Oil)[c]
Total Energy Input, Higher Heating Value (HHV) (One CTG)	975 MMBtu/hr (Natural Gas)[b]
	1,026 MMBtu/hr (Fuel Oil)[c]

Notes:

[a] Natural gas is primary fuel. Fuel oil used as a backup fuel when natural gas is not available under an interruptible gas supply contract.

[b] CTG firing natural gas.

[c] CTG firing fuel oil.

Figure 2-4 provides a simplified process flow schematic of the proposed simple cycle generating units. Each combustion turbine power block will include an advanced firing temperature combustion turbine air compressor section, gas combustion system (dry low NO_X combustors), power turbine, and a generator. Each gas turbine generator set is designed to produce a nominal 81 MW of gross electrical power (at 74.6°F, 72% RH, 14.69 psia).

2.4 Operation

The Facility will be capable of operating up to a maximum of 24 hours and up to 20,000 hours per year for all eight units combined (i.e., an average of 2,500 hours per year per unit). Each turbine will be permitted to operate (on average) up to 1,000 hours per year on backup fuel oil (i.e., 8,000 hours per year for all eight units combined) in the event that natural gas is not available. The CTGs can be operated on a continuous basis with the capability to operate down to load levels as low as 60 percent for maximum flexibility. The facility will employ approximately 10 personnel once fully operational.

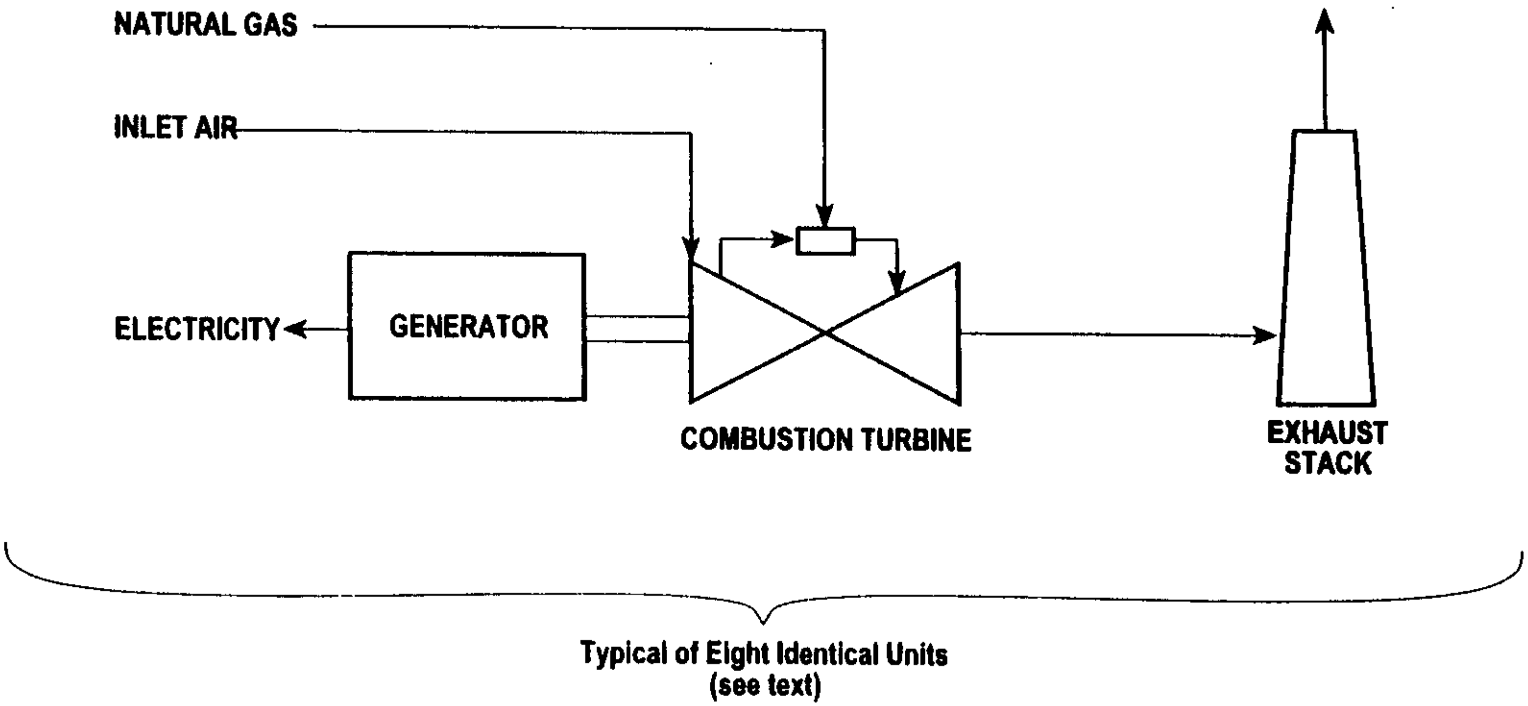

Figure 2-4
Simple Cycle Generating Units
Duke Energy Fort Pierce, LLC
Fort Pierce Generating Station
Fort Pierce, Florida

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3.0 Emission Source Information

3.1 Proposed Facility Emission Sources

3.1.1 Regulated Pollutants

The principal sources of emissions from the proposed Facility will be the eight simple cycle combustion turbines. Summaries of the hourly emissions (ppmvd and lb/hr) for each simple cycle combustion turbine train at maximum and partial load (i.e., 100, 75, and 60 percent) are provided in Tables 3-1 through 3-3 for natural gas fired operation, and in Tables 3-4 through 3-6 for oil fired operation. Due to economic efficiency and equipment control considerations, the turbines will not be operated at partial loads less than the lowest indicated load ratings except during startup and shut down conditions.

The CTG hourly emissions and emission characteristics were calculated at the design ambient temperatures of 101°F (peak summer), 74.6°F (mean annual), and 27°F (minimum winter). This assumption provides a basis for the calculation of emissions over the entire range of conditions under which the turbines may operate. The emission estimates provided in the tables are based on the following assumptions:

- Sulfur content of natural gas is less than 2 grains per 100 standard cubic feet (scf)
- Sulfur content of low sulfur No. 2 distillate fuel oil is 0.05 percent sulfur, by weight
- All particulate emissions are less than or equal to 10 micrometers (PM-10)
- All Volatile Organic Compound (VOC) hourly emissions are represented as methane (CH_4) and result from the combustion of natural gas or fuel oil.

Table 3-1
Summary of Maximum Hourly Emissions and Emission Characteristics (Maximum Load, Natural Gas Firing)
General Electric Model GE 7EA Simple Cycle Combustion Turbine Generator Set
Duke Energy Fort Pierce, LLC
Fort Pierce, Florida

Parameter		Operating Scenario		
		1	2	3
Load	%	100	100	100
Unit Output Per CTG	kWe	76264	79733	91140
Net Unit Heat Rate (HHV)	Btu/kWh	12131	11984	11677
Temperature	°F	101	74.6	27
Relative Humidity	%	40	72	81
Fuel		Natural Gas	Natural Gas	Natural Gas
Stack Parameters				
Stack Temperature	°F	1013	1005	977
Stack Height	ft	93	93	93
Stack Diameter	ft	15	15	15
Exit Velocity	ft/sec	134.4	137.4	147.4
Stack Emissions Per CTG				
NO_X	ppm_{vd}	12.0	12.0	12.0
	lb/hr	40.0	41.0	47.0
CO	ppm_{vd}	25.0	25.0	25.0
	lb/hr	50.0	52.0	58.0
VOC	ppm_{vw}	1.4	1.4	1.4
	lb/hr	1.8	1.8	2.0
PM-10	lb/MMBtu	0.013	0.013	0.011
	lb/hr	11.0	11.0	11.0
SO_2	lb/MMBtu	0.0071	0.0068	0.0072
	lb/hr	6.0	6.0	7.0

Notes:

1. NO_X concentrations are corrected to 15% O_2
2. NO_X emissions based on GE guarantee of 12 ppm_{vd} @ 15% O_2 at 100% load only
3. CO emissions based on GE guarantee of 25 ppm_{vd} at 100% load only
4. VOC emissions based on GE guarantee of 1.4 ppm_{vw} at 100% load only
5. SO_2 emissions based on sulfur in fuel content of 2 gr/100 SCF
6. All PM emissions assumed to be PM-10
7. Inlet fogging assumed for all temperatures above 59 °F at 100% load

Table 3-2
Summary of Maximum Hourly Emissions and Emission Characteristics (75 Percent Load, Natural Gas Firing)
General Electric Model GE 7EA Simple Cycle Combustion Turbine Generator Set
Duke Energy Fort Pierce, LLC
Fort Pierce, Florida

Parameter		Operating Scenario 4	Operating Scenario 5	Operating Scenario 6
Load	%	75	75	75
Net Unit Output Per CTG	kWe	52553	58210	68146
Net Unit Heat Rate (HHV)	Btu/kWh	13645	13156	12498
Temperature	°F	101	74.6	27
Relative Humidity	%	40	72	81
Fuel		Natural Gas	Natural Gas	Natural Gas
Stack Parameters				
Stack Temperature	°F	1094	1064	1017
Stack Height	ft	93	93	93
Stack Diameter	ft	15	15	15
Exit Velocity	ft/sec	106.5	110.9	118.0
Stack Emissions Per CTG				
NO_X	ppm_{vd}	12.0	12.0	12.0
	lb/hr	31.0	33.0	37.0
CO	ppm_{vd}	25.0	25.0	29.0
	lb/hr	38.0	40.0	52.0
VOC	ppm_{vw}	1.4	1.4	1.4
	lb/hr	1.4	1.4	1.6
PM-10	lb/MMBtu	0.0021	0.0020	0.0020
	lb/hr	11.0	11.0	11.0
SO_2	lb/MMBtu	0.017	0.016	0.014
	lb/hr	5	5	6

Notes:

1. NO_X concentrations are corrected to 15% O_2
2. SO_2 emissions based on <2.0 grains S/100 SCF natural gas

Table 3-3
Summary of Maximum Hourly Emissions and Emission Characteristics (60 Percent Load, Natural Gas Firing)
General Electric Model GE 7EA Simple Cycle Combustion Turbine Generator Set
Duke Energy Fort Pierce, LLC
Fort Pierce, Florida

Parameter		**Operating Scenario** 7	8	9
Load	**%**	60	60	60
Net Unit Output Per CTG	**kWe**	41782	46288	54182
Net Unit Heat Rate (HHV)	**Btu/kWh**	15169	14690	13900
Temperature	**°F**	101	74.6	27
Relative Humidity	**%**	40	72	81
Fuel		Natural Gas	Natural Gas	Natural Gas
Stack Parameters				
Stack Temperature	**°F**	1100	1100	1059
Stack Height	**ft**	93	93	93
Stack Diameter	**ft**	15	15	15
Exit Velocity	**ft/sec**	96.9	100.3	106.3
Stack Emissions Per CTG				
NO_X	**ppm_{vd}**	12.0	12.0	12.0
	lb/hr	28.0	29.0	32.0
CO	**ppm_{vd}**	42.0	25.0	25.0
	lb/hr	58.0	36.0	39.0
VOC	**ppm_{vw}**	2.0	1.4	1.4
	lb/hr	1.8	1.2	1.4
PM-10	**lb/MMBtu**	0.019	0.017	0.016
	lb/hr	11.0	11.0	11.0
SO_2	**lb/MMBtu**	0.0068	0.0079	0.0072
	lb/hr	4	5	5

Notes:
1. NO_X concentrations are corrected to 15% O_2
2. SO_2 emissions based on <2.0 grains S/100 SCF natural gas

Table 3-4 Summary of Maximum Hourly Emissions and Emission Characteristics (Maximum Load, Oil Firing) General Electric Model GE 7EA Simple Cycle Combustion Turbine Generator Set Duke Energy Fort Pierce, LLC Fort Pierce, Florida				
		Operating Scenario		
Parameter		10	11	12
Load	**%**	100	100	100
Net Unit Output Per CTG	**kWe**	72383	80272	94266
Net Unit Heat Rate (HHV)	**Btu/kWh**	12788	12527	12210
Temperature	**°F**	101	74.6	27
Relative Humidity	**%**	40	72	81
Fuel		Distillate Oil	Distillate Oil	Distillate Oil
Stack Parameters				
Stack Temperature	**°F**	1023	1005	971
Stack Height	**ft**	93	93	93
Stack Diameter	**ft**	15	15	15
Exit Velocity	**ft/sec**	130.2	137.3	149.6
Stack Emissions Per CTG				
NO_X	**ppm_{vd}**	42.0	42.0	42.0
	lb/hr	146.0	159.0	182.0
CO	**ppm_{vd}**	20.0	20.0	20.0
	lb/hr	39.0	42.0	47.0
VOC	**ppm_{vw}**	3.5	3.5	3.5
	lb/hr	4.5	4.5	5.0
PM-10	**lb/MMBtu**	0.029	0.027	0.025
	lb/hr	25.0	25.0	26.0
SO_2	**lb/MMBtu**	0.054	0.054	0.055
	lb/hr	46	50	58

Notes:

1. NO_X concentrations are corrected to 15% O_2
2. NO_X emissions based on GE guarantee of 42 ppm_{vd} @ 15% O_2 at 100% load only
3. CO emissions based on GE guarantee of 20 ppm_{vd} at 100% load only
4. VOC emissions based on GE guarantee of 3.5 ppm_{vw} at 100% load only
5. SO_2 emissions based on sulfur in fuel content of 0.05 percent by weight
6. All PM emissions assumed to be PM-10.

Table 3-5 Summary of Maximum Hourly Emissions and Emission Characteristics (75 Percent Load, Oil Firing) General Electric Model GE 7EA Simple Cycle Combustion Turbine Generator Set Duke Energy Fort Pierce, LLC Fort Pierce, Florida				
		Operating Scenario		
Parameter		13	14	15
Load	**%**	75	75	75
Net Unit Output Per CTG	**kWe**	54126	60017	57981
Net Unit Heat Rate (HHV)	**Btu/kWh**	14077	13610	13009
Temperature	**°F**	101	74.6	27
Relative Humidity	**%**	40	72	81
Fuel		Distillate Oil	Distillate Oil	Distillate Oil
Stack Parameters				
Stack Temperature	**°F**	1091	1061	1016
Stack Height	**ft**	93	93	93
Stack Diameter	**ft**	15	15	15
Exit Velocity	**ft/sec**	107.3	111.9	119.4
Stack Emissions Per CTG				
NO_X	**ppm_{vd}**	42.0	42.0	42.0
	lb/hr	119.0	128.0	143.0
CO	**ppm_{vd}**	20.0	20.0	20.0
	lb/hr	31.0	33.0	36.0
VOC	**ppm_{vw}**	3.5	3.5	3.5
	lb/hr	3.5	3.5	4.0
PM-10	**lb/MMBtu**	0.034	0.032	0.030
	lb/hr	24.0	24.0	25.0
SO_2	**lb/MMBtu**	0.054	0.054	0.054
	lb/hr	38	41	46

Notes:

1. NO_X concentrations are corrected to 15% O_2
2. SO_2 emissions based on 0.05% Sulfur in fuel oil, by weight

Table 3-6 Summary of Maximum Hourly Emissions and Emission Characteristics (60 Percent Load, Oil Firing) General Electric Model GE 7EA Simple Cycle Combustion Turbine Generator Set Duke Energy Fort Pierce, LLC Fort Pierce, Florida				
		Operating Scenario		
Parameter		16	17	18
Load	%	60	60	60
Net Unit Output Per CTG	kWe	43035	47725	56036
Net Unit Heat Rate (HHV)	Btu/kWh	15592	15146	14403
Temperature	°F	101	74.6	27
Relative Humidity	%	40	72	81
Fuel		Distillate Oil	Distillate Oil	Distillate Oil
Stack Parameters				
Stack Temperature	°F	1100	1100	1057
Stack Height	ft	93	93	93
Stack Diameter	ft	15	15	15
Exit Velocity	ft/sec	97.5	101.1	107.4
Stack Emissions Per CTG				
NO_X	ppm_{vd}	42.0	42.0	42.0
	lb/hr	104.0	112.0	126.0
CO	ppm_{vd}	20.0	20.0	20.0
	lb/hr	28.0	29.0	32.0
VOC	ppm_{vw}	3.5	3.5	3.5
	lb/hr	3.0	3.0	3.5
PM-10	lb/MMBtu	0.037	0.036	0.032
	lb/hr	23.0	24.0	24.0
SO_2	lb/MMBtu	0.055	0.054	0.053
	lb/hr	34	36	40

Notes:

1. NO_X concentrations are corrected to 15% O_2
2. SO_2 emissions based on 0.05% Sulfur in fuel oil, by weight

The maximum expected annual emissions from the Facility (assuming average annual ambient conditions, CTGs fired with natural gas and low sulfur No. 2 distillate fuel oil) and the corresponding Prevention of Significant Deterioration (PSD) significant emission rates are as follows:

Pollutant	Maximum Expected Annual Emissions (tons/yr)[a,b]	PSD Threshold for Major Sources (tons/yr)
NO_X	1,010	40
CO	580	100
VOC	32	40
PM-10[c]	170	15
SO_2	274	40

[a] Emissions are based on maximum hourly emission rates.
[b]Based on 2,500 hours operation per turbine, up to 1000 hours (per turbine) of which could be on fuel oil
[c]All PM assumed to be PM-10.

Since the projected emissions of NO_X, CO, PM-10, and SO_2 are all greater than their respective PSD thresholds, the project is a major source as defined by the regulations governing PSD for each of these pollutants. As such, a PSD permit is required, including a demonstration of BACT, and a dispersion modeling analysis to demonstrate that there will not be a violation of any National Ambient Air Quality Standards (NAAQS) and that no PSD increments will be exceeded.

3.1.2 Non-regulated Pollutants

EPA's guidance on the assessment of non-regulated "toxic pollutants" requires that permit applicants evaluate emissions of toxic substances for those pollutants that the proposed Facility could emit in amounts potentially of concern to the public. In the case of combustion turbines, potential toxic air pollutants could include acetaldehyde, benzene, formaldehyde, and heavy metals. A more complete analysis of these non-regulated pollutants is provided in Section 6.5.2.

3.2 Other Emission Sources

In order to facilitate the determination of PSD increment consumption and compliance with the National Ambient Air Quality Standards (NAAQS) resulting from the operation of the Facility, an inventory of existing and permitted emission sources would normally be requested from the Florida Department of Environmental Protection (FDEP) for all emission sources with the potential to interact with emissions from the proposed Facility. However, the dispersion modeling analysis of the proposed new emission sources (see Section 6) indicates that the Facility will result in an "insignificant" impact (as defined by FDEP and EPA) on ambient air quality at all locations and for all applicable averaging periods. Therefore, it will not be necessary to consider other sources of emission in the analysis.

4.0 Applicable Regulations

4.1 Applicable Pollutants

Expected emissions rates for the proposed Facility's combustion turbines were summarized in Section 3. The maximum expected annual emissions from the Facility for NO_X, CO, PM-10, and SO_2 will each exceed the applicable PSD threshold making the Facility a major source of emissions under the regulations governing PSD (40 Code of Federal Regulations [CFR] 52.21). As a result, an ambient air quality impact analysis and demonstration of BACT are required for each of these pollutants.

4.2 Ambient Air Quality Impact Analysis Requirements

The ambient limits with which the proposed project must comply are the NAAQS for SO_2, NO_2, CO, and particulate matter (PM-10) (40 CFR 50 and Rule 62-204.240, Florida Administrative Code [FAC]), and the PSD Class II and Class I increments for SO_2, PM-10, and NO_2 (40 CFR 52 and Rule 62-204.260, FAC). These limits are summarized in Table 4-1. Analyses of the proposed Facility emissions (see Section 6) demonstrate that the Facility will be in compliance with all state and federal ambient air quality regulations.

Also listed in Table 4-1 are the "significant" impact levels for each pollutant. The impact area for the proposed Facility is defined as the area from the source of emissions to the distance at which the emissions from the Facility no longer produce a significant impact for each pollutant. When the ambient concentrations at a particular location attributable to a given source are below the significant impact levels, the impact of the source at that location is considered to be insignificant. There are no significant impact levels defined for VOC emissions since VOCs are not a modeled pollutant.

TABLE 4-1
Applicable Ambient Air Quality Limits and Significant Impact Levels
Duke Energy Fort Pierce, LLC
Fort Pierce, Florida

Pollutant and Averaging Period	National Ambient Air Quality Standards		Florida	PSD Increments		Significant Impact Level (Class II Areas)
	Primary	Secondary	AAQS	Class II	Class I	
SO_2						
3-hour	-	1300[a]	1300[a]	512[a]	25[a]	25
24-hour	365[a]	-	260[a]	91[a]	5[a]	5
Annual	80	-	60	20	2	1
NO_2						
Annual	100	100	100	25	2.5	1
CO						
1-hour	40,000[a]	-	40,000[a]	[b]	[b]	2,000
8-hour	10,000[a]	-	10,000[a]	[b]	[b]	500
PM-10[c]						
24-hour	150[a]	150[a]	150[a]	30	8	5
Annual	50	50	50	17	4	1

(Concentrations in μg/m³)

Notes:
[a] Concentrations not to be exceeded more than once per year, on an average basis.
[b] No increments applicable.
[c] Particulate matter with aerodynamic diameters less than or equal to 10 μm.

4.3 Emission Limits and Performance Standards

4.3.1 Combustion Turbines

New Source Performance Standards (NSPS) have been developed by the United States Environmental Protection Agency (US EPA) for stationary gas turbines (40 CFR 60, Subpart GG). These NSPS impose maximum allowable emission limitations on NO_X and SO_2 emissions from turbines with peak load heat inputs of greater than 10 MMBtu/hr. For the proposed turbines, Subpart GG specifies that the maximum NO_X emissions will be less than:

$$STD = 0.0075 \frac{(14.4)}{Y} + F$$

where:

STD = Maximum allowable NO_X emissions in percent by volume (15% O_2, dry)

Y = Manufacturers rated heat input (Kj/watt-hour)
= 12.644 Kj/watt-hr (Natural Gas)
= 13.217 Kj/watt-hour (Fuel Oil)

F = NO_X emission allowance based on FBN content
= .00060 (Fuel Oil)
= 0 (Natural Gas)

Therefore STD = 0.0081% or 81 ppm (Natural Gas)
0.0088 or 88 ppm (Fuel Oil)

Subpart GG also specifies that SO_2 emissions be less than 0.015 percent by volume (15 percent oxygen) and that fuels contain less than 0.8 percent sulfur by weight. The NO_X and SO_2 emissions from the proposed Facility will be substantially less than those specified by Subpart GG of the NSPS and the sulfur content of natural gas and low sulfur No. 2 distillate fuel oil will be substantially less than that specified by Subpart GG of the NSPS.

US EPA has also recently issued an "interpretative rule" on the applicability of sections 112(g) and (h) of the Clean Air Act to new combustion turbines. According to the rule, published in the April 21, 2000 Federal Register, all stationary combustion turbines constructed after June 29, 1998 are subject to case-by-case maximum available control technology (MACT) for hazardous air pollutants (HAPs). The EPA rule clarifies that the MACT review requirement applies to combustion turbines that are part of a combined cycle power plant, as well as those used in a simple cycle configuration. This interpretive ruling is essentially a clarification of an existing rule and its implications are that the project will have to demonstrate that the level and control of HAPs from the combustion turbines will reflect MACT. For combustion turbines firing natural gas and fuel oil, this assessment would essentially be limited to the emissions of formaldehyde, although there may be lesser amounts of acetaldehyde, benzene, polycyclic organic matter (POM), polycyclic aromatic hydrocarbons (PAH), and trace amounts of heavy metals. As discussed in Section 6.5.2, the emissions of Formaldehyde are estimated to be less than 1 lb/hr. No individual HAP will exceed 10 tons/yr, and all HAPs combined will not exceed 25 tons/yr. Therefore, there is no requirement for case-by-case MACT for this facility.

4.3.2 Fuel Oil Storage Tanks

There are four No. 2 distillate fuel oil storage tanks on-site which may emit a regulated pollutant (VOCs). All four fuel oil storage tanks are subject to 40 CFR 60, Kb. Annual emissions are estimated to be less than 1.0 ton per year.

4.4 Monitoring Requirements

4.4.1 Pre-construction Monitoring

PSD regulations and Rule 62-212.400, FAC, have a potential requirement for the development and operation of an ambient air quality and/or meteorological monitoring station for the purpose of determining ambient air quality and meteorological conditions in the immediate vicinity of the site. Air quality monitoring could be required for any criteria pollutant emitted in significant amounts if representative data are not available. Exemptions from the pre-construction monitoring requirements can be obtained if:

- Representative meteorological data is available for use in the air quality modeling;
- The predicted ambient impact(s) attributable to the operation of the proposed turbine or the existing ambient pollutant concentrations are less than the US EPA prescribed *de minimis* level of concentrations; and
- The proposed source is located in an area not affected by other major stationary sources so that existing ambient monitoring data from representative regional sites are appropriate for ambient background concentrations.

Section 6.2 describes the meteorological data available for use in the transport and dispersion modeling analysis. Personnel from the FDEP have indicated that they consider these data representative of the area of the proposed Facility site. Therefore, pre-application meteorological monitoring will not be required for this project.

Transport and dispersion modeling performed for the proposed turbine configuration has indicated that the predicted air quality impacts (Section 6.0) attributable to the proposed

Facility for all pollutants emitted in excess of the significant emission rates are less than the US EPA defined *de minimis* ambient impact levels for NO_X, PM-10, SO_2, and CO. Therefore, pre-construction monitoring for these pollutants will not be required. Ozone is not an emitted pollutant, rather it forms as a result of complex chemical reactions between precursor emissions of VOCs and NO_X in the presence of sunlight and higher temperatures, resulting in peak ozone levels occurring at mid-day during the warmest months of the year. The proposed Facility will be a source of both NO_X and VOC emissions, with proposed maximum allowable emissions of 822 and 29 tons/year, respectively. Maximum NO_X emissions of 822 tons/year will occur only under the scenario of maximum oil firing (i.e., 1,000 hours/year in all eight units). Under the preferred operating scenario of 100 percent natural gas-fired operation, NO_X emissions will be only 310 tons/year. The Facility will be located in St. Lucie County, which is designated as being in attainment of all ambient air quality standards, including ozone. Background ozone monitoring data was requested from FDEP for use in lieu of pre-construction monitoring. FDEP staff provided three years (1996 to 1998) of ozone monitoring results from Fort Pierce, approximately 8 kilometers northeast of the project site. The results of this monitoring are summarized below:

Monitored Ozone Concentrations in St. Lucie County (ppm)			
Year	**Site Identification Number**	**1st High**	**2nd High**
1996	3960 002 F01	0.082	0.072
1997	3960 002 F01	0.085	0.082
1998	12 111 1002	0.095	0.095

These monitoring results are well below the 1-hour ozone standard of 0.12 ppm, indicating that the area is in attainment for ozone.

4.4.2 Operational Monitoring

The Facility, and in particular the proposed new turbines, will comply with all applicable operational monitoring requirements imposed by Federal and State regulations. Sections 4.4.2.1 and 4.4.2.3 summarize the monitoring requirements that are applicable to this project.

4.4.2.1 Combustion Turbines

In addition to any one-time or periodic performance testing requirements, the Facility will install, calibrate, maintain, and operate the necessary monitoring equipment to monitor and record the fuel consumption in the combustion turbines as specified by 40 CFR 60, Subpart GG, and 40 CFR 75.

4.4.2.3 Fuel

Due to the expected requirement to continuously monitor NO_X emissions and due to the inherently low sulfur content in natural gas and low sulfur No. 2 distillate fuel oil, Duke may seek a waiver of the fuel monitoring requirements of 40 CFR 60 (Subparts Dc and GG). Otherwise, annual testing would be anticipated.

4.4.2.4 Other

The Facility will comply with all other operational monitoring and reporting requirements as may be determined necessary by FDEP in order to ensure compliance with any Federal or State rules or regulations. This will include any applicable future monitoring, reporting, and record keeping required as a result of the implementation of Title V (Operating Permits) and Title IV (Acid Deposition Control) of the Clean Air Act Amendments of 1990. Additionally, this will include Rules 62-213 (Operating Permits for Major Sources of Air Pollution) and 62-214 (Acid Rain Program Requirements), FAC.

5.0 Demonstration of Best Achievable Control Technology

5.1 Introduction

Under PSD regulations, a new or modified "major source" is required to apply BACT for any pollutant emitted in "major" or "significant" amounts. As discussed in section 3.0, the proposed Facility will have the potential to emit NO_X, PM-10, CO, and SO_2 in "significant" quantities. A BACT analysis is therefore required for these pollutants. The purpose of this review is to demonstrate that the air pollution control measures to be utilized at the proposed Facility represent BACT as defined by Section 169 of the Clean Air Act:

> "An emission limitation (including a visible emissions standard) based on the maximum degree of reduction of each pollutant subject to regulations under the Act which would be emitted from any proposed major stationary source or major modification, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, economic impacts and other costs, determines is achievable for such source or modifications through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment of innovative fuel combination techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which will exceed the emissions allowed by any applicable standard under 40 CFR Parts 60 and 61."

Both the US EPA and FDEP require that the demonstration of BACT described above must follow the "top-down" approach. This approach will ensure that a BACT demonstration considers the most stringent level of control technology available. If it can be shown that this level of control is technically, economically, or environmentally infeasible, then the next most stringent level of control is determined and similarly evaluated. The process continues until the BACT level under consideration cannot be eliminated by any substantial or unique economic or environmental objectives. For this project, the only emission sources for which BACT will apply will be the eight GE 7EA combustion turbines.

Currently, the only pollutants from combustion turbines for which a new source performance standard exists are nitrogen oxides and sulfur oxides. Firewater pump engines that will be installed on-site will not be operated concurrently with the combustion turbines (except during periodic performance and reliability testing) and are therefore exempt from BACT review and will not be considered further.

The purpose of this section is to demonstrate that the proposed emission control systems and methods will be representative of BACT. The following sections present the available control technology alternatives and a demonstration of BACT for each pollutant that will be emitted in significant amounts from the Facility, as discussed previously in Section 3.

A BACT analysis is presented for each emissions unit that contributes to the total emissions of a pollutant.

5.2 Methodology

The top-down BACT analysis presented here consists of the following steps:

1) Identify and rank feasible control technologies
2) Determine the economic, energy, and environmental impacts of the control technology
3) Propose the highest remaining technology as BACT

The first step is to compile a list of all feasible control options for each pollutant subject to PSD review. These control options are then ranked and listed in order of overall control effectiveness in descending order, with the most effective control option at the top of the list. The second step is to determine the potential economic, energy, and environmental impacts the control option would have on the project, starting at the top of the list. The last step is to propose the most effective control (which was not eliminated in the second step) as BACT. The three-step process described above simply compresses into a single step, for purposes of description, the first three steps described in US EPA's Draft New Source

Review Workshop Manual (October 1990) but is otherwise essentially the same as the BACT process outlined in the Draft Manual.

Identification of Feasible Control Options

The first step in the BACT analysis is the identification of feasible control options, including consideration of transferable and innovative control measures that may not have previously been applied to the source type under analysis. The minimum requirement for a BACT proposal is an option that meets federal NSPS limits, applicable air quality standards, or other minimum state or local requirements that would prevail in the absence of BACT decision making. In a top-down BACT analysis, the option that represents lowest achievable emission rate (LAER), the most stringent permitted emission limitation achieved in practice by another unit in the same class or category of source, must be examined as the starting point for the analysis. Options that are technically infeasible for the intended application are eliminated from further review. If there is only a single feasible option, or if the applicant is proposing the "top," or LAER alternative, then no further analysis is required.

If several feasible options are identified, the next step is applied to identify and compare the economic, energy, and environmental impacts of the options. Technical considerations and site-specific issues will often play a role in BACT determinations.

Economic Impact Analysis

The cost estimation methodology used in this BACT analysis is consistent with the latest US EPA guidance (Office of Air Quality Planning and Standards [OAQPS] Cost Control Manual [EPA 453/b-96-001]). Vendor quotes and engineering estimates are the basis for calculating the total capital and operating costs, or cost differentials, for control options, and are documented accordingly. Standard engineering economic analyses are used to convert all costs to equivalent annual costs, so that the pollution control cost-effectiveness, in dollars per ton of pollutant controlled, may be calculated for comparison with other control options. The cost estimates include capital costs and annual operation and maintenance costs. Capital costs include both direct costs (equipment purchase costs, sales taxes, freight), installation costs (foundations, supports, field erection, electrical, piping, insulation, painting), and indirect capital costs (engineering, construction, contractor fees, start-up, performance tests, contingencies, and interest during construction). Annual costs also include direct and indirect costs. Direct costs include instrumentation, losses in generating revenue, operating and supervision labor, routine replacement parts, maintenance labor, maintenance replacement parts, and contingencies. Annual indirect costs include overhead, administration, property taxes, and insurance.

The following variables, equations, and assumptions were used to evaluate the cost effectiveness of alternative control strategies for the pollutants in question:

$$CRF = i(1+i)^n/((1+i)^n-1)$$

where,

CRF = capital recovery factor

i = interest rate (assumed at 7 percent)

n = equipment life (assumed 10 years for the equipment and 3 years for the catalyst)

Table 5-1 presents the site-specific economic assumptions used in the BACT analysis. These assumptions include labor rates, estimates of operational and maintenance labor requirements, cost and usage rates of consumables, and indirect costs. The cost effectiveness of a control technology is calculated by dividing the total annualized costs of the control technology by the potential reduction in emissions from the application of the control technology.

TABLE 5-1
Summary of BACT Costing Assumptions
Duke Energy Fort Pierce, LLC
Fort Pierce Generating Facility
Fort Pierce, Florida

Cost Item	Cost Assumption	Cost
Operator Labor Rate	0.5 Hours/Shift	$35.00/Hour
Supervisor Labor Rate	15 percent of Operating Labor	-
Instrumentation Labor	40 Hours/Year	$35.00/Hour
Catalyst Replacement Labor	320 man-hours every 3 years[1]	$35.00/Hour
Material	100 percent of Labor	-
Electricity	NA	$0.065/kWh
Overhead	60 percent of labor and materials	-
Administrative	2 percent of Total Installed Cost	-
Property Taxes	1 percent of Total Installed Cost	-
Insurance	1 percent of Total Installed Cost	-

[1] 8 workers for 40 hours every 3 years.

Energy Impact Analysis

Two forms of energy impacts that may be associated with a control option can normally be quantified. The first impact is an increase in energy consumption resulting from increased heat rate (which can be shown as a reduction of electrical generation resulting from the application of the control technology due to increased parasitic load or back pressure). The second impact is the reduced unit availability due to additional maintenance requirements for the applied control technology.

Environmental Impact Analysis

The primary focus of the environmental impact analysis is the reduction in ambient concentrations of the pollutants being controlled. Increases and decreases in other criteria or non-criteria pollutants may occur with some technologies, and should also be identified. Non-air impacts, such as solid waste disposal and increased water consumption, may be an issue as well.

5.3 Simple Cycle Generating Units

The proposed Facility will include eight simple cycle generating units. Each unit will consist of a GE Model 7EA combustion turbine generator set, and a dedicated exhaust stack. The combustion turbines will operate up to 2,500 hours per year using natural gas as a primary fuel, although they will be capable of operating up to 1,000 hours/yr on backup distillate fuel oil during periods of natural gas curtailment. For operational flexibility, Duke is requesting that the Facility be permitted to operate up to 20,000 hours per year for all eight units combined, or 2,500 hours per unit, whichever is less restrictive. An analysis of BACT for the emissions from the simple cycle generating units is provided below.

5.3.1 Nitrogen Oxides (NO_X)

There are several technologies to consider for controlling NO_X emissions from combustion turbines in a simple cycle configuration. These are categorized into pre-combustion controls and post-combustion controls. The following is a discussion of the potential control technologies and a discussion of their technical feasibility.

Pre-Combustion NO_X Control Technologies

Water or Steam Injection - The injection of water or steam into the combustor of a combustion turbine quenches the flame and absorbs heat, reducing the combustion temperature. This temperature reduction minimizes the formation of thermal NO_X. Water or steam injection also allows more fuel to be burned without overheating critical turbine parts, increasing the combustion turbine's maximum power output. For gas-fired operation, this technology has effectively been superceded in the industry by Dry Low NO_X (DLN) combustor technology which produces lower NO_X emissions and improves combustion turbine unit energy efficiency. Therefore, water/steam injection technology will not be considered in this analysis for gas-fired operation. During oil-fired operation, water injection is still considered to be a viable means of emission control, with the capability of achieving 60 to 80 percent control efficiency, with NOx emissions as low as 42 ppmvd.

Dry Low NO_X Combustors. There are two potential types of DLN combustors that may be appropriate for this application. These are lean pre-mix and catalytic technologies. The lean pre-mix type is the most popular DLN combustor available. Conventional combustors are diffusion controlled. Fuel and air are injected separately with combustion occurring at stoichiometric interfaces. This method of combustion can result in combustion "hot spots" which produce higher levels of NO_X. In the lean pre-mix combustor, air and fuel are mixed before they enter the combustor. Lean pre-mix combustors have only been developed for gas-fired turbines and the more advanced designs are capable of achieving a 70 to 90 percent NO_X reduction with a range of NO_X concentration from 9 to 25 ppmvd. DLN technology has been successfully installed and operated at several combustion turbine facilities. Therefore, the lean pre-mix DLN technology is considered to be feasible for use at the Facility.

The other type of DLN combustor is a catalytic combustor, such as Catalytica's XONON™ system, that uses a catalyst inside the combustor where the air/fuel mixture passes through the catalyst. Combustion typically occurs at much lower temperatures when compared to a standard combustor. This reduction in combustion temperature can significantly reduce the formation of thermal NO_X. Emissions of NO_X from catalytic combustors are typically below 5 ppmvd. Catalytica Combustion Systems has successfully demonstrated the XONON™ system on a pilot scale 1.5 MW combustion turbine located in Santa Clara, CA (in October

1998). This system was operated with NO_X concentrations observed to be below 3 ppm. Catalytic combustors have not been applied commercially to large gas turbines such as the GE 7EA, and discussions with Catalytica indicate that the first possible commercial availability of the XONON system for large combustion turbines is still several years away. A company, in cooperation with Catalytica and General Electric, is in the process of commercially demonstrating the XONON system at a power plant being developed in Central California (Pastoria District Energy Center). The Pastoria project has recently started the siting process in California and is not expected to be operational until the third quarter of 2003 and initial operating results are not expected until early 2004. The Pastoria facility will utilize two one-on-one GE 7FA combined cycle powers blocks and is being designed to utilize SCR control technology if XONON technology is not commercially available before the facility commences operation, or if it does not perform as expected in practice. Because the Facility is scheduled to begin construction in May of 2001 and commence operation in June 2002, and since this technology has not been demonstrated on GE 7EA gas turbines in practice for a facility of the size being proposed, this technology is not considered feasible for use on this project.

Post Combustion NOx Control Technologies

Three post-combustion controls exist for combustion turbines. These are the $SCONO_X$™, selective catalytic reduction (SCR), and Cannon Technology's Low Temperature Oxidation (LTO).

$SCONO_X$™ System. The $SCONO_X$™ system is produced by Goal Line Environmental Technologies and is currently being licensed by Asea Brown Boveri (ABB). The $SCONO_X$™ system uses a coated catalyst to oxidize and adsorb NO_X onto the catalyst. The system consists of a catalyst bed installed in a location where the temperature is between 280 °F and 700 °F. NO_X emissions are oxidized to NO_2, and then adsorbed onto the catalyst. The catalyst requires periodic regeneration, up to several times per hour, using a regeneration gas containing 4 percent hydrogen, 3 percent nitrogen, and 1.5 percent carbon dioxide. The regeneration gas is created by reacting natural gas with air in the presence of a nickel oxidation catalyst which is electrically heated to 1,900 °F. This gas is then mixed with steam and passed over a second catalyst to form the regeneration gas. The regeneration gas is introduced into the catalyst rack through a system of piping, valves, and louvers.

The catalyst rack being regenerated must be isolated from the exhaust gases. This is accomplished using two sets of louvers located both upstream and downstream of the catalyst module. The regeneration gas exits the catalyst rack and is ducted back into the exhaust stream, upstream of the $SCONO_X$™ system. The $SCONO_X$™ louver dampers isolate the catalyst system from the exhaust gases during regeneration. These louver dampers and associated supports are all exposed to the exhaust gas stream which could present long-term maintenance and reliability problems. The $SCONO_X$™ demonstration project in Southern California has experienced numerous outages as a result of failures of the louver system. ABB, as part of its scale-up process, has reportedly redesigned the louver system and is testing the redesigned system to determine the function and reliability. The $SCONO_X$™ system has achieved NO_X emissions of less than 3.5 ppmvd on the Southern California demonstration project that is a much smaller turbine than the size of what is being proposed herein. Goal Line Environmental has made claims that the $SCONO_X$™ system is capable of achieving emission rates as low as 2.0 ppmvd. However, these claims represent data derived from the pilot facility in Southern California which is a GE LM-2500 based combustion turbine combined cycle cogeneration facility (rated at approximately 23 MW) and does not represent emissions from a Frame 7 sized simple cycle combustion turbine project (nominally rated at 80 MW). $SCONO_X$™ technology has not been demonstrated on a combustion turbine the size of that being proposed herein.

Several US EPA Regions (including Region IV) have notified the state agencies that $SCONO_X$ technology should be considered technically feasible for large combustion turbine projects. Additionally, a San Diego Union Tribune newspaper article (January 28, 2000) reported that Pacific Gas and Electric (PG&E) Generating Company has announced that it would install the $SCONO_X$™ system on one of the four combustion turbines at its Otay Mesa Power Project. However, the hearing transcripts for the Otay Mesa Power Plant licensing process (through the California Energy Commission), indicate that PG&E Generating Company qualifies the January 28th announcement with the statement that the $SCONO_X$ system will be installed "if it is able to be commercialized" (California Energy Commission, November 15, 1999 Hearing Transcript). Additionally, PG&E Generating Company, in concert with ABB, is requesting a 3-year demonstration period for the $SCONO_X$ system in the Otay Mesa Power Plant air quality permits, and is incorporating provisions to install an SCR system if the SCONOx™ system fails to meet contractual guarantees (California Energy Commission, March 2, 2000 Status Conference Transcript).

As discussed above, SCONOx™ is an emerging technology that shows promise for future combined cycle applications (i.e., it has not been proven for large turbines) where gas temperatures can be lowered in the heat recovery process to a narrow temperature range in the Heat Recovery Steam Generator (HRSG) of between 280 °F and 700 °F. Since the simple cycle unit exhaust gas streams will be in the range of 1,100 °F, SCONOx™ substantial cooling of the exhaust stream would be required for the system to function properly. Therefore, SCONOx™ is not considered to be a technically feasible NOx emission control option for use on the proposed simple cycle units and will not be considered further.

Selective Catalytic Reduction. Selective catalytic reduction (SCR) involves the injection of ammonia into the flue gas stream where it selectively reacts with NOx in the presence of oxygen and a catalyst to form molecular nitrogen and steam. Because the reactions normally proceed at temperatures between 1,600 and 1,800°F, a catalyst is used to promote the reactions at lower temperatures. Reduction catalysts are divided into two groups: base metal (lower temperature - primarily vanadium, platinum, or titanium) and zeolite (higher temperature). Both groups exhibit advantages and disadvantages in terms of operating temperature, reducing agent/NO_X ratio, and optimum oxygen concentration. A disadvantage common to platinum and base metal catalysts is the narrow range of temperatures in which the reactions will proceed. Operating above the maximum temperature results in oxidation of NH_3 to either nitrogen oxides (thereby actually increasing NO_X emissions) or ammonium nitrate. Vanadium-titanium catalyst systems have been shown to operate efficiently at temperatures from 550 to 800°F, which is significantly higher than earlier platinum catalyst systems. However, the vanadium-titanium catalyst systems begin to break down when continuously operated at temperatures above this range or under the wide temperature swings that are normal for simple-cycle peaking turbines. Consequently, operating above the maximum temperature for the catalyst system would result in the oxidation of NH_3 to either nitrogen oxides (thereby actually increasing NO_X emissions) or ammonium nitrate and would permanently damage the catalyst.

Zeolite is the only currently available SCR catalyst material that may be used at the elevated temperatures and load swings associated with peaking turbine installations. However, zeolite has a maximum temperature limitation of approximately 1,025°F, which corresponds to the normal operating exhaust temperatures of the GE 7EA combustion turbines. There are only four known installations of this technology on gas-fired simple cycle peaking units, and none of these has a long-term history of success. All are substantially smaller than the 80 MW GE 7EA turbines being proposed for this project, and three of the turbines have operating histories of less than only a few thousand hours. Operating experience with the existing installations has indicated that there is a pattern of degradation of SCR performance after only a few hundred hours of operation, and/or catastrophic catalyst failure. Ammonia slip has also been observed to increase over time.

A second concern associated with SCR technology is the effect of sulfur-bearing fuels on the catalyst. The problems associated with the use of sulfur-bearing fuels are due to the formation of ammonium bisulfate, NH_4HSO_4, and ammonium sulfate, $(NH_4)_2SO_4$. These are ammonia salts formed by the chemical reaction between the sulfur in the fuel and ammonia injected for NO_x control and they are emitted to the atmosphere as particulate matter. Ammonium bisulfate is a sticky substance which forms in the lower temperature section of the system where it deposits on the combustion turbine downstream surfaces. These surface deposits result in increased pressure drop, reduced power output, and lower cycle efficiency. To prevent corrosion damage, the system must be shut down periodically and water-washed, thereby reducing availability. While ammonium sulfate is not corrosive, its formation also contributes to increased pressure drop, reduced power output, lower cycle efficiency, and higher particulate emissions. Because of these problems, the use of SCR is not considered to be technically feasible.

Also of significant concern is the handling and use of ammonia. Ammonia is regulated under the EPA Risk Management Program and Title III, Section 302 of the Superfund Amendments and Reauthorization Act of 1986 (SARA). Releases of ammonia to the atmosphere may occur in several ways, including ammonia slip, or it can be accidentally released during transport, transfer, or storage. In addition, ammonia is potentially a PM-10 precursor and concerns about the potential health impacts of secondary emissions, such as nitrous oxide and nitroamines, have been raised.

Cannon Technology's Low Temperature Oxidation (LTO). The Cannon LTO technology was primarily developed to control emissions from large steam boilers. The basic operation of the LTO system injects ozone into a cooled exhaust gas (approximately 300 °F) to oxidize NO_X, CO, and SO_2 to nitrates, carbonates, and sulfates. These higher oxides are absorbed by a dilute nitric acid solution in a scrubber. Testing on natural gas fired boilers has shown NO_X concentrations below 3.5 ppmvd at 3 percent oxygen and vendor literature indicates NO_X guarantees of less than 4 ppmvd.

The LTO system has been demonstrated on relatively small natural gas-fired boilers ranging in size from 4.1 to 16.7 MMBtu/hr. The volume of exhaust gas from a 16.7 MMBtu/hr boiler will be approximately 145,457 standard dry cubic feet per hour (SDCFH). The exhaust gas volume from one of the combustion turbines proposed for use on this project will be 28,857,148 SDCFH. This would require a drastic scale-up of the LTO technology. Additionally, the scrubber solution would result in the generation of additional pollution (scrubber waste), and would require disposal. Cannon Technology literature indicates the scrubber waste can be discharged to sanitary sewer systems, but this option has not been verified and would directly impact costs. Therefore, the LTO technology was rejected as a technically infeasible NO_X control measure for this project.

Control Technology Ranking

Based on the above discussion, there are only three technically feasible NO_X control technologies identified for this Project – high temperature SCR, DLN, and/or water/steam injection. There are numerous examples of projects where DLN has been permitted as BACT with emission rates between 9 and 15 ppm natural gas fired units. There are no examples of high temperature SCR technology being permitted (and successfully demonstrated) as BACT for a large scale turbine installation. The proposed BACT for this project is DLN combustors which are capable of achieving a NO_X emission rate of 12.0 ppmvd at 15 percent oxygen.

Because SCR has the potential for greater removal efficiency than DLN combustors, the cost-effectiveness of the system to reduce NO_X emissions was also evaluated. The cost analysis is presented below.

Selective Catalytic Reduction Cost Effectiveness

High temperature SCR is not considered by Duke Energy to be a technically feasible option for a dual fuel (oil/gas) turbine. However its hypothetical cost effectiveness was calculated for comparison with other technologies. Capital costs associated with supplying a base SCR system (natural gas operation only) to each turbine are shown in Table 5-2. SCR capital equipment includes the catalyst housing, auxiliary equipment, instrumentation, catalyst, and structural support. The basic equipment cost is estimated at $2,485,450 based on a quote from Englehard. With other direct and indirect installation and start-up costs, the total capital investment for installing a SCR system is estimated at $4,511,200.

Table 5-2
Combustion Turbine NO_x BACT Analysis
71 Percent NO_x Control Efficiency for a SCR system (Per Turbine)
Duke Energy Fort Pierce, LLC
Fort Pierce Generating Facility
Fort Pierce, Florida

Cost Item	Cost Factor	Reference	Cost ($1999)
Direct Costs (Dc)			
Purchased Equipment Costs (PEC)			
Basic Equipment & Auxiliaries	As Estimated, A	Vendor Quote	$2,037,250
Instrumentation	0.1 X A	(EPA, 1995a)	$203,700
State Sales Taxes	0.07 X A	State Sales Tax	$142,600
Freight	0.05 X A	(EPA, 1995a)	$101,900
PEC Subtotal (B)			**$2,485,450**
Direct Installation Costs (DIC)			
Foundations & Supports	0.08 X B	(Ulrich, 1984)	$198,800
Labor	0.14 X B	(EPA, 1990a)	$348,000
Electrical	0.04 X B	(EPA, 1990a)	$99,400
Piping	0.02 X B	(EPA, 1995a)	$49,700
Insulation	0.01 X B	(EPA, 1995a)	$24,900
Painting	0.01 X B	(EPA, 1990a)	$24,900
DIC Subtotal	0.3 X B	(EPA, 1990a)	**$745,700**
Total Dc	PEC+DIC	-	**$3,231,200**
Indirect Costs (IDC)			
Engineering	0.10 X B	(EPA,1990a)	$248,500
Construction Overhead	0.05 X B	(EPA,1990a)	$124,300
Contractor Fees	0.10 X B	(EPA,1990a)	$248,500
Contingencies	0.20 X B	(EPA,1990a)	$497,100
Start-Up	0.02 X B	(EPA,1990a)	$49,700
Performance Testing	0.01 X B	(EPA,1990a)	$24,900
Simple Interest During Construction	PEC X 7% X 0.5 YEARS	Estimate	$86,990
Total IDC		-	**$1,280,000**
Total Capital Investment (TCI)	**Dc + IDC**		**$4,511,200**

Table 5-2
Combustion Turbine NO_x BACT Analysis
71 Percent NO_x Control Efficiency for a SCR system (Per Turbine)
Duke Energy Fort Pierce, LLC
Fort Pierce Generating Facility
Fort Pierce, Florida

Cost Item	Cost Factor	Reference	Cost ($1999)
Operating Cost Factors For The SCR			
Cost Data			
Interest Rate	7%	***CAPITAL RECOVERY FACTOR (CRF)***	
Catalyst Life	3	0.380	
Equipment Life	10	0.1440	
Direct Annual Costs, $/Yr			
	FACTOR	**REFERENCE**	**COSTS, $/Yr**
Power Loss Due To Pressure Drop Across Catalyst	0.3% per inch of pressure drop @ $0.065/kWh and 245 KW loss	Vendor	$39,780
Operating Labor	$30/hr @ 3 hr/12-hr shift	Industry Average/Estimate	$65,700
Supervisory Labor	15 % of operating labor	(EPA,1993a)	$9,855
Maintenance Labor	$30/hr @ 4 hr/12-hr shift	Estimate	$87,600
Maintenance Materials	100 % of maintenance labor	(EPA,1993a)	$87,600
Revenue Loss During Cat, Replacement (A)	72 Hours at $0.065/kWh	Estimate	$381,888
Catalyst Cleaning	80 Man-hours per year	Estimate	$2,800
Catalyst Replacement Labor (B)	8 Workers for 40 hours	Estimate	$11,200
Catalyst Replacement (Cr) (C)	$1,077,000 every 3 years including disposal	Vendor Quote	$1,077,000
Sales Tax (D)	7%	State Tax Rate	$75,390
Capital Recovery	[A+B+C+D] * CRF	(EPA, 1995a)	$587,281
TOTAL DIRECT ANNUAL COSTS, $/YR			**$880,600**
Indirect Annual Costs, $/Yr			
Overhead	60% of All Labor Main. Costs	(EPA,1990a)	$111,033
Insurance & Administration	3% of TCI	(EPA,1990a)	$135,336
Capital Recovery	CRF X TCI	N/A	$ +649,612
Property Tax	1% of TCI	Estimate	$45,112
			$941,093
Total Annual Costs, $/Yr	**$1,821,693**		
Total Net NOx Reductions (TPY)	36	Natural gas operation, 71% removal, 2,500 hours/yr operation	
Incremental Cost Effectiveness, $/Ton	**$50,602**		

Annualized costs for operation of SCR on each turbine are also summarized in Table 5-2. The total annualized cost of SCR operation is estimated at $1,821,693. The amount of NO_X that would be removed annually by the SCR would be approximately 36 tons, based on 2,500 hours of natural gas operation and an estimated removal efficiency of 71 percent. This would result in a cost of removal of $50,602/ton of NO_X. Clearly, this is not a cost effective technology for controlling of NO_X emissions from the simple cycle turbines at the proposed Facility.

Proposed BACT for NO_X

Duke proposes to utilize DLN combustors in the turbines to limit NO_X emissions during gas fired operation to an average NO_X emission rate of 12.0 ppmvd corrected to 15 percent oxygen. During oil fired operation, Duke proposes to utilize good combustor design and water injection to limit NOx emissions to 42 ppmvd corrected to 15 percent oxygen.

5.3.2 Carbon Monoxide (CO) and Volatile Organic Compounds (VOCs)

Only two feasible technologies exist to control CO and VOC emissions from a combustion turbine: good combustor design and high temperature oxidation catalyst.

Good Combustor Design. CO and VOCs are formed during the combustion process due to incomplete combustion of the carbon present in the fuel. The formation of CO and VOCs is limited by designing the combustion system to completely oxidize the fuel carbon to CO_2. This is achieved by ensuring that the combustor is designed to allow for complete mixing of the combustion air and fuel at combustion temperatures (in excess of 1,800°F) with an excess of combustion air. Higher combustion temperatures tend to reduce the formation of CO and VOCs, but increase the formation of NO_X. The application of steam/water injection or staged combustion tends to lower combustion temperatures (in order to reduce NO_X formation), increasing CO and VOC formation. A good combustor design will minimize the formation of CO and VOCs while reducing the combustion temperature and NO_X emissions. The proposed combustion turbines already incorporate this control technology into the design, controlling CO and VOC emissions to 25 ppmvd and 1.4 part per million based on wet volume (ppmvw), at 100 percent load, respectively.

Oxidation Catalyst. The oxidation catalyst is typically a precious metal catalyst bed located in the exhaust system. The catalyst enhances oxidation of CO and VOCs to CO_2, without the addition of any reactant. Oxidation catalysts have been successfully installed on combined cycle combustion turbines for a number of years, achieving high levels of control in areas designated as non-attainment for CO. Traditionally, combustion turbine vendor estimates for CO and VOC emissions tend to be very conservative. As a result, early CO BACT analyses have shown that the installation of an oxidation catalyst was cost effective. However, as actual source testing data was generated for combustion turbines without oxidation catalysts, the results showed that the CO emission estimates were significantly greater than the actual CO emissions measured. Regardless of this fact, oxidation catalysts are considered to be technically feasible for use on combustion turbines.

Control Technology Ranking

Aside from the use of good combustion design and operating practices, the only feasible method of controlling CO emissions from a GE 7EA combustion turbine is the use of an oxidation catalyst. Several 7EA units have recently been permitted in Florida and a summary of the determinations for CO is contained in Table 5-3. Table 5-4 summarizes recent BACT determinations for VOC emissions from combustion turbines. The CO and VOC emissions being proposed for this project are consistent with these recent determinations.

Economic Analysis of CO and VOC Controls

An initial capital equipment cost of $1,515,075 for a basic oxidation catalyst system was provided by Engelhard and included the catalyst modules, internal frame, and internal seals. The remainder of the cost analyses were based on accepted engineering economic principles. Annual capital and operating costs for the installation and operation of the oxidation catalyst system for one combustion turbine were estimated using US EPA Control Cost Manual methodology. These costs include the operating and maintenance labor, supervision labor, material costs, catalyst cleaning and replacement costs (both labor and expenses), and capital recovery for both the initial equipment purchase and periodic catalyst replacement costs.

TABLE 5-3
Summary of Florida CO BACT Determinations for GE 7EA Turbines
Duke Energy Fort Pierce, LLC
Fort Pierce Generating Facility
Fort Pierce, Florida

Technology	Permitted CO Emission Rate ppmvd at 15% O_2	Project	Turbine Type
Clean Fuels, Good Combustion Design	25 (gas) 20 (oil)	FPC Int. City, FL	General Electric 7EA
Clean Fuels, Good Combustion Design	25 (gas) 20 (oil)	TECO Hardee, FL	General Electric 7EA
Clean Fuels, Good Combustion Design	25 (gas) 20 (oil)	GPU Gainesville, FL	General Electric 7EA

TABLE 5-4
Summary of VOC BACT Determinations for Combustion Turbines
Duke Energy Fort Pierce, LLC
Fort Pierce Generating Facility
Fort Pierce, Florida

Permitted VOC Emission Rate ppmvd at 15% O_2	Project
0.6	BACT, Bear Mountain Ltd., CA RBLCID Number CA-0858 08/19/1994
1.0	BACT, Florida Power and Light, FL RBLCID Number FL-0053 03/14/1991
1.5	BACT, Lakewood Cogeneration, L.P., NJ RBLCID Number NJ-0013 04/01/99
1.6	BACT, Florida Power and Light, FL RBLCID Number FL-0052 06/05/1991
1.7	BACT, Public Service of Colorado, CO RBLCID Number CO-0024 05/01/1996
1.9	BACT, Southern California Gas RBLCID Number CA-0418 10/29/1991
2.0	BACT, Tiverton Power Associates, RI RBLCID Number RI-0018 02/13/99
4.0	BACT, Blue Mountain Power, LP., PA RBLCID Number PA-0148 07/31/1996

The most cost-effective installation of the oxidation catalyst equipment (including the catalyst module, auxiliary equipment, instrumentation, catalyst, and structural supports) results in an estimated total annual cost of $1,157,071, and will reduce the combustion turbine CO emissions by 52 tons per year (80 percent CO control efficiency) and VOC emissions by 1 ton per year (45 percent VOC control efficiency). The cost-effectiveness of this system is $21,832/ton of CO and VOC removed. Table 5-5 presents the economic analyses (for a single turbine) for the installation of an oxidation catalyst to control CO and VOC emissions.

Table 5-5
Combustion Turbine CO and VOC BACT Analysis (Per Turbine)
Duke Energy Fort Pierce, LLC
Fort Pierce Generating Facility
Fort Pierce, Florida

Cost Item	Cost Factor	Reference	Cost ($1999)
Direct Costs (Dc)			
Purchased Equipment Costs (PEC)			
Basic Equipment & Auxiliary Equipment (A)	As Estimated	Vendor Quote	$1,241,875
Instrumentation	0.1 X A	(EPA, 1995a)	$124,200
State Sales Taxes	0.07 X A	State Sales Tax	$86,900
Freight	0.05 X A	(EPA, 1995a)	$62,100
PEC Subtotal (B)			**$1,515,075**
Direct Installation Costs (DIC)			
Foundations & Supports	0.08 X B	(Ulrich, 1984)	$121,200
Labor	0.14 X B	(EPA, 1990a)	$212,100
Electrical	0.04 X B	(EPA, 1990a)	$60,600
Piping	0.02 X B	(EPA, 1995a)	$30,300
Insulation	0.01 X B	(EPA, 1995a)	$15,200
Painting	0.01 X B	(EPA, 1990a)	$15,200
DIC Subtotal		(EPA, 1990a)	**$454,600**
Total Dc	PEC+DIC	-	**$1,969,700**
Indirect Costs (IDC)			
Engineering	0.10 X B	(EPA,1990a)	$151,500
Construction Overhead	0.05 X B	(EPA,1990a)	$75,800
Contractor Fees	0.10 X B	(EPA,1990a)	$151,500
Contingencies	0.03 X B	(EPA,1990a)	$45,500
Start-Up	0.02 X B	(EPA,1990a)	$30,300
Performance Testing	0.01 X B	(EPA,1990a)	$15,200
Simple Interest During Construction	PEC X 7% X 0.5 YEARS	Estimate	$53,027
Total IDC		-	**$522,827**
Total Capital Investment (TCI)	**Dc + IDC**		**$2,492,500**

Table 5-5
Combustion Turbine CO and VOC BACT Analysis (Per Turbine)
Duke Energy Fort Pierce, LLC
Fort Pierce Generating Facility
Fort Pierce, Florida

Cost Item	Cost Factor	Reference	Cost ($1999)
Operating Cost Factors For The Oxidation Catalyst			
Cost Data			
Interest Rate	7%	***CAPITAL RECOVERY FACTOR (CRF)***	
Catalyst Life	3	0.38	
Equipment Life	10	0.1440	
Direct Annual Costs, $/Yr			
Power Loss Due To Pressure Drop Across Catalyst	0.1% per inch of pressure drop @ $0.065/kWh and 245 KW loss	Vendor	$39,780
Operating Labor	$30/hr @ 1 hr/12-hr shift	Industry Average/Estimate	$21,900
Supervisory Labor	15 % of operating labor	(EPA,1993a)	$3,285
Maintenance Labor	$30/hr @ 1 hr/12-hr shift	Estimate	$21,900
Maintenance Materials	100 % of maintenance labor	(EPA,1993a)	$21,900
Revenue Loss During Cat, Replacement (A)	72 hours at $0.065/kWh	Estimate	$381,888
Catalyst Cleaning	80 man-hours per year	Estimate	$2,800
Catalyst Replacement Labor (B)	8 workers for 40 hours every 3 years	Estimate	$11,200
Catalyst Replacement (Cr) (C)	$1,006,540 every 3 years including disposal	Vendor Quote	$1,006,540
Sales Tax (D)	7%	State Tax Rate	$70,458
Capital Recovery	[A+B+C+D] * CRF	(EPA, 1995a)	$558,632
TOTAL DIRECT ANNUAL COSTS, $/YR			**$670,200**
Indirect Annual Costs, $/Yr			
Overhead	60% of All Labor Main. Costs	(EPA,1990a)	$28,251
Insurance & Administration	3% of TCI	(EPA,1990a)	$74,775
Capital Recovery	CRF X TCI	N/A	$358,920
Property Tax	1% of TCI	Estimate	$24,925
TOTAL INDIRECT ANNUAL COSTS, $/YR			**$486,871**
Total Annual Costs, $/Yr	**$1,157,071**		
Total Net CO Reductions (TPY)	52	80% Removal Efficiency, 2,500 hours/yr operation	
Total Net VOC Reductions (TPY)	1	45% Removal Efficiency, 2,500 hours/yr operation	
Incremental Cost Effectiveness, $/Ton	**$21,832**		

Environmental Impacts

Although the use of an oxidation catalyst has the technical potential to further reduce CO and VOC emissions (when compared to good combustion design and operating practices), its application would also result in some negative environmental impacts that must be considered. The primary environmental concerns regarding catalytic oxidation include:

- Disposal of spent catalyst
- Increase in PM-10 emissions
- Increase of SO_3 emissions

Spent catalyst from catalytic oxidation systems will have to be disposed of either by the user or through some type of agreement with the vendor. There is some concern about the future possibilities that catalyst might have to be treated as a hazardous waste. The quantity of catalyst to be disposed would be significant and on the order of approximately 2 tons/year per unit.

PM-10 emissions can increase due to the additional oxidation of sulfur and ammonia present in the combustion turbine exhaust gas. The combustion turbine oxidizes any sulfur compounds in natural gas (either naturally occurring or added as an odorant) to SO_2. The SO_2 would be further oxidized to SO_3 across the oxidation catalyst and could be emitted either as a sulfate or as H_2SO_4. Additionally, the oxidation catalyst may oxidize unreacted ammonia (from the SCR) to form PM-10.

Given the fact that the emissions of CO from the proposed Facility have been shown (see Section 6) to result in an insignificant impact on ambient air quality, further reductions in CO emissions from the Facility do not appear to be environmentally justified. This is supported by the fact that there are no nonattainment areas for CO in Florida, and there is no threat to the ambient air quality standards for CO as a result of the operation of the Facility.

Proposed BACT for CO and VOC

Catalytic oxidation has primarily been used to meet specialized requirements such as LAER, typically in areas that are designated as nonattainment for CO ambient air quality standards. Most of the recent permits listed in the RBLC indicate that combustion control practices are the preferred method of CO control on combustion turbines. To date there has been no BACT determination for VOC controls applied to combustion turbines other than combustion controls and good combustion practices.

Considering all the relevant impacts, it is proposed that BACT for CO and VOC be the most efficient combustion possible while achieving the proposed BACT for NOx. The maximum emissions for CO and VOC (and proposed BACT) will be 25 ppmvd and 1.4 ppmvw, respectively, at 100 percent load during natural gas firing. During limited periods of fuel oil firing, the maximum emissions of CO and VOC (and proposed BACT) will be 20 ppmvd and 3.5 ppmvd, respectively, at 100 percent load.

5.3.3 Particulate Matter (PM-10)

Emissions of particulate matter less than 10 micrometers in diameter (PM-10) from the combustion turbine result primarily from inert solids contained in the fuel and unburned fuel hydrocarbons which agglomerate to form particles. The only feasible PM-10 emissions control technology for the combustion turbines is the use of low sulfur, low ash fuel. Post combustion particulate matter controls have never been applied to combustion turbines, the primary reasons being the very large volumes of low concentration exhaust air and excessive back pressure. The use of Electrostatic Precipitators (ESPs) and baghouse are considered technically infeasible and environmentally unjustified.

PM-10 emission rates are inherently extremely low because of very high combustion efficiencies and the clean burning nature of natural gas and low sulfur No. 2 distillate fuel oil. Clean fuels such as these are required to prevent damage to the turbine blades and other high-precision turbine components. Therefore, their use is in and of itself, a highly efficient method of controlling emissions. Based on the lack of technically feasible controls and the fact that add-on controls have not been used or proposed to reduce PM-10 emissions from combustion turbines, the use of clean burning natural gas and low ash transportation grade No. 2 fuel oil is therefore proposed as BACT for PM-10 emissions from the combustion turbines.

5.3.4 Sulfur Dioxide (SO_2)

The proposed Facility will utilize natural gas and low sulfur No. 2 distillate fuel oil (0.05 percent sulfur, by weight). The use of natural gas will result in negligible SO_2 emissions while the use of low sulfur No. 2 distillate fuel oil produces SO_2 emissions in proportion to the sulfur content of the fuel.

Add-on SO_2 controls have not been required on gas or low sulfur No. 2 distillate fuel oil-fired combustion turbines because of the extremely low sulfur content that is typical of these fuels. A review of US EPA's RACT/LAER/BACT clearinghouse for recent SO_2 BACT determinations for combustion turbines and boilers identified low sulfur natural gas and low sulfur No. 2 distillate fuel oil as BACT for all recent BACT determinations. The proposed Facility will emit a maximum of only 236 tons of SO_2 per year from the simple cycle generating units (based on 1500 hours per year operation on gas and 1000 hours per year on fuel oil). The SO_2 emissions are directly proportional to the sulfur content of the fuel the project will be burning. The above emissions estimates are based on a fuel sulfur content less than 2 grains per 100 standard cubic feet of natural gas. Therefore, the use of clean burning natural gas and low sulfur No. 2 distillate fuel oil is consistent with recent BACT determinations and is therefore being proposed as BACT for this Facility.

5.3.5 Sulfuric Acid Mist (H_2SO_4)

During the combustion process approximately 10 percent of the sulfur dioxide (SO_2) is oxidized to sulfur trioxide (SO_3). SO_3 is hydrophilic and combines with available moisture to form sulfuric acid mist (H_2SO_4) when the temperature drops below the acid dew point. For a combustion turbine, this condition is normally only reached after several minutes and some distance from the plant when the exhaust stream has dispersed and cooled.

Emission reduction alternatives for H_2SO_4 mist are the same as those reviewed for emissions of SO_2. Limiting the fuel sulfur content reduces the sulfur entering the combustion process and reduces the resultant SO_3, thus minimizing H_2SO_4 emission formation. The use of natural gas and low sulfur No. 2 distillate fuel oil is proposed as BACT for H_2SO_4 mist. Due to the low emissions of SO_2 expected from the turbine, the formation of sulfuric acid mist is expected to be insignificant.

5.3.6 Other Pollutants

The combustion of natural gas and low sulfur No. 2 distillate fuel oil may release trace amounts of a number of materials such as formaldehyde, acetaldehyde, lead, beryllium, mercury, fluorides, arsenic, benzene, manganese, chromium, nickel, copper, cadmium, and radionuclides. As discussed in Section 3.0, the emissions of these pollutants from this Facility are not expected to be significant.

5.4 BACT Summary

Table 5-6 presents the control technologies proposed as BACT for the proposed Duke Energy Fort Pierce, LLC.

TABLE 5-6
Summary of Proposed BACT
Duke Energy Fort Pierce, LLC
Fort Pierce Generating Facility
Fort Pierce, Florida

Pollutant	Control Technology	Proposed BACT
Nitrogen Oxides (NOx)	Dry Low-NO_X for Natural Gas Wet Injection and Limited Fuel Oil usage	12.0 ppmvd at 15% O_2 (Natural Gas) 42 ppmvd, at 15% O_2 (Fuel Oil)
Carbon Monoxide (CO)	Good Combustor Design and Operating Practice	25 ppmvd (Natural Gas, 100% Load) 20 ppmvd (Fuel Oil, 100% Load)
Volatile Organic Compounds (VOCs)	Good Combustor Design and Operating Practice	1.4 ppmvw (Natural Gas, 100% Load) 3.5 ppmvw (Fuel Oil, 100% Load)
Sulfur Dioxide (SO_2)	Pipeline Natural gas or Low Sulfur Fuel Oil	Sulfur content $\leq$ 2 grains/100 scf) (Natural Gas) 0.05% S by weight (Fuel Oil)
Particulate Matter (PM-10)	Pipeline Natural gas or low ash fuel oil, Good Combustor Design and Operating Practice	11 lb/hr (Natural Gas, 100% Load) 26 lb/hr (Fuel Oil, 100% Load)

6.0 Ambient Air Quality Impact Analysis

The dispersion modeling analyses documented herein were designed to assess the potential impact on ambient air quality of the proposed Facility located near Fort Pierce, Florida. Prior to initiation of the air quality impact analysis performed for the Facility, a meeting was held on July 26, 2000 with FDEP modeling staff to review and approve the modeling protocol. The dispersion models, meteorological data, modeling methodology, and results of the analyses described in this application are consistent with the previously approved protocol.

6.1 Dispersion Model

Dispersion modeling results were obtained using EPA's short-term Industrial Source Complex Model (ISCST3), version 00101 (EPA, 1999). The short-term model was used exclusively to determine short-term concentrations (i.e., 1-hour to 24-hour averaging periods) as well as annual average concentrations.

6.2 Meteorological Input Data

The meteorological database used in the air quality modeling analyses consisted of 5 years (1987 to 1991) of surface observations and upper air data from West Palm Beach, Florida. FDEP staff provided the meteorological data. The West Palm Beach Airport is located approximately 75 km to the south of the proposed project site in an area of similar topographic features. The anemometer height used by the observing station is reported to be 10 meters. These data were reportedly processed using EPA's meteorological data preprocessor program PCRAMMET, and the results made ready for input into the ISCST3 model.

6.3 Receptor Grids

A Cartesian grid was utilized for all analyses. Initial modeling was performed on a receptor grid beginning at a location 100 meters from the turbine exhaust stacks (approximate nearest fenceline). Receptor spacing was set at 100 m spacing from 100 m out to 3.0 km, 250 m from 3.0 km out to 6 km, 500 m spacing from 6.0 km out to 12 kilometers, and 1.0 km beyond 12 km. The modeling approach was based on the assumption that a refined receptor grid (minimum 100 meter spacing) would be used as necessary in order to determine maximum predicted concentrations in various areas of the initial grid.

6.4 Other Modeling Considerations

The ISC model contains options that determine the way in which calculations are made. The choice of options was made consistent with EPA's current recommended approach, including the regulatory default option. The options utilized in the analysis included stack tip downwash, final plume rise, buoyancy-induced dispersion, building wake effects, and rural dispersion coefficients. Data obtained from the 1990 United States census indicates that the population density of St. Lucie County is 101.3 people per square kilometer. This is well below the 750 people per square kilometer that an Auer Land Use analysis would trigger a requirement to use urban dispersion coefficients. Additionally, a review of topographic maps within 3 kilometers of the project site indicates that the area is predominantly rural in nature and there are no areas of high density housing or industry to suggest that an urban classification would be warranted. The ISC calms processor was used to account for calm winds in the calculations. The area around the proposed Facility is generally flat, therefore terrain elevations were not used in the modeling.

The emissions from the proposed Facility will be released from eight 93-foot exhaust stacks (simple cycle units). The dispersion modeling was designed to incorporate building wake and downwash effects attributable to the largest onsite structure, namely the air intake housings on each unit. No consideration was given to the effects of adjacent turbine stack(s) in the building wake effects analysis since the centerline spacing between the stack(s) will be sufficiently large to avoid those effects.

6.5 Dispersion Modeling Methodology and Results

6.5.1 Facility Emission Sources

The dispersion modeling results reported in this section are based on the emission source information discussed previously in Section 3.0. Tables 3-1 through 3-6 summarized the emissions and emission source characteristics for the simple cycle combustion turbine trains. The emissions summarized in these tables are maximum expected emission rates computed at ambient conditions representative of the range of ambient conditions expected for operation. It is noted that these emissions also are representative of BACT as demonstrated in Section 5.0. With the exception of NO_x emissions, all emissions were modeled at the maximum hourly rate. NO_x emissions for the simple cycle units were modeled at the effective hourly emission rate corresponding to natural gas usage of 2500 annual operating hours (i.e., maximum hourly emission rate x 2500/8760) and fuel oil usage of 1000 annual operating hours (i.e., maximum hourly emission rate x 1000/8760).

The modeling analyses described in this report were based on four different objectives, namely to determine or demonstrate: (1) the maximum impact and radius of significant impact of the proposed Facility during maximum/full load operation; (2) the maximum impact and radius of significant impact of the proposed Facility based on part load operation (i.e., as low as 60 percent load); (3) PSD increment consumption in the area surrounding the Facility; and (4) compliance with the NAAQS. In accordance with US EPA and FDEP guidance, if maximum predicted impacts due to the operation of the proposed Facility are determined to be less than the EPA-defined level of significant impacts presented below (43 FR 26398), further modeling analysis to demonstrate compliance with the applicable PSD increments and NAAQS will not be required.

Significant Impact Concentration ($\mu g/m^3$)

Pollutant	Annual	1-Hour	3-Hour	8-Hour	24-Hour
SO_2	1	-	25	-	5
PM-10	1	-	-	-	5
NO_x	1	-	-	-	-
CO	-	2000	-	500	-

Modeling analyses were performed for winter and summer ambient temperatures as well as for the average annual ambient temperature for three operational load levels in order to ensure that maximum concentrations would be identified under all operating scenarios. Electronic copies of all relevant input and output files used in the modeling analyses presented herein are submitted on a CD-ROM as part of this application (see Appendix B for index).

6.5.1.1 Maximum Impact and Radius of Significant Impact

The maximum impact and radii of significant impact for each pollutant emitted from the proposed Facility was determined by modeling the maximum expected emissions as previously presented in Tables 3-1 through Table 3-6. NO_x emissions for the simple cycle units were modeled at the hourly rate corresponding to their annual hours of operation for natural gas and fuel oil. This analysis was performed for SO_2, PM-10, NO_x, and CO emissions since the emissions for these pollutants will be greater than the US EPA-defined significant emission rates.

The results of this analysis are summarized (for the winter operating conditions) in Tables 6-1 through 6-6. The results of the modeling analyses indicated that maximum predicted concentrations generally occurred for winter conditions (27 °F ambient conditions). Modeling was performed for all ambient and operating conditions, however only the winter ambient conditions are presented here since those conditions generally result in the highest concentrations. The model input and output files are included electronically on the CD-ROM that is being submitted with this application. As shown in Tables 6-1 through 6-6, the maximum predicted offsite concentrations attributable to the operation of the proposed Facility are less than the significant impact levels for all pollutants. It is noted that this is true for all operating scenarios and for all seasons. As a result, the impact of the proposed Facility is considered to be "insignificant" for all criteria pollutants and no further dispersion modeling or ambient air quality impact analysis is necessary.

Since the emissions from all eight turbines will be released from eight identical stacks that will be located in close proximity to one another, all emissions were modeled as a single source with the emission release characteristics of a single stack. Because the emissions were treated as a single source, pollutant emissions from the simple cycle turbines were modeled using a nominal emission rate of 10 grams/second (79.3 lb/hr). The results were then scaled up or down according to the ratio of the proposed emission rates (Tables 3-1 through 3-3) to the nominal emission rate. Detailed calculations can be found in spreadsheets contained in Appendix B.

Table 6-1
Summary of Dispersion Modeling Results
Maximim Predicted Offsite Concentrations and Radii of Significant Impact (Maximum Load, Natural Gas Firing)
Duke Energy Fort Pierce, LLC
Fort Pierce Generating Facility
Fort Pierce, Florida

Pollutant	Averaging Period	Significant Impact Level (ug/m3)	Maximum Predicted Offsite Concentration (ug/m3) 1987	1988	1989	1990	1991	Maximum Radius of Significant Impact (km)
PM-10	Annual	1	0.028 Location (554500, 3033000) ROI = 0 km	0.029 Location (554500, 3033000) ROI = 0 km	0.030 Location (553500, 3033500) ROI = 0 km	**0.032** Location (553500, 3033500) ROI = 0 km	**0.032** Location (554000, 3033000) ROI = 0 km	0
	24-hour	5	0.33 Location (552000, 3037000) ROI = 0 km	0.32 Location (543000, 3032000) ROI = 0 km	0.33 Location (549500, 3025500) ROI = 0 km	**0.34** Location (550000, 3036000) ROI = 0 km	**0.34** Location (552000, 3033000) ROI = 0 km	0
NO_x	Annual	1	0.032 Location (554500, 3033000) ROI = 0 km	0.033 Location (554500, 3033000) ROI = 0 km	0.035 Location (553500, 3033500) ROI = 0 km	0.036 Location (553500, 3033500) ROI = 0 km	**0.037** Location (554000, 3033000) ROI = 0 km	0
SO_2	Annual	1	0.017 Location (554500, 3033000) ROI = 0 km	0.017 Location (554500, 3033000) ROI = 0 km	0.018 Location (553500, 3033500) ROI = 0 km	**0.019** Location (553500, 3033500) ROI = 0 km	**0.019** Location (554000, 3033000) ROI = 0 km	0
	24-hour	5	0.21 Location (552000, 3037000) ROI = 0 km	0.21 Location (543000, 3032000) ROI = 0 km	0.21 Location (549500, 3025500) ROI = 0 km	0.21 Location (550000, 3036000) ROI = 0 km	**0.22** Location (552000, 3033000) ROI = 0 km	0
	3-hour	25	0.85 Location (545000, 3039000) ROI = 0 km	0.86 Location (549000, 3039000) ROI = 0 km	0.86 Location (563000, 3022750) ROI = 0 km	0.79 Location (569500, 3017000) ROI = 0 km	**0.87** Location (568000, 3012000) ROI = 0 km	0
CO	1-Hour	2000	15.0 Location (561700, 3030500) ROI = 0 km	14.6 Location (561500, 3030600) ROI = 0 km	17.7 Location (562300, 3030300) ROI = 0 km	16.9 Location (562900, 3029600) ROI = 0 km	**18.1** Location (561500, 3030400) ROI = 0 km	0
	8-Hour	500	**4.43** Location (559500, 3026100) ROI = 0 km	4.18 Location (544000, 3025000) ROI = 0 km	4.06 Location (572000, 3014000) ROI = 0 km	3.88 Location (549000, 3039000) ROI = 0 km	3.90 Location (557000, 3032500) ROI = 0 km	0

Notes:
Location = (UTM Coordinates)
Bold indicates maximum value

Table 6-2
Summary of Dispersion Modeling Results
Maximim Predicted Offsite Concentrations and Radii of Significant Impact (75 Percent Load, Natural Gas Firing)
Duke Energy Fort Pierce, LLC
Fort Pierce Generating Facility
Fort Pierce, Florida

Pollutant	Averaging Period	Significant Impact Level (ug/m3)	Maximum Predicted Offsite Concentration (ug/m3) 1987	1988	1989	1990	1991	Maximum Radius of Significant Impact (km)
PM-10	Annual	1	0.033 Location (555500, 3032500) ROI = 0 km	0.034 Location (555500, 3032500) ROI = 0 km	0.036 Location (555500, 3032500) ROI = 0 km	0.038 Location (553500, 3033500) ROI = 0 km	**0.039** Location (555500, 3032500) ROI = 0 km	0
	24-hour	5	0.41 Location (550500, 3028500) ROI = 0 km	0.41 Location (553000, 3036000) ROI = 0 km	0.40 Location (550500, 3041000) ROI = 0 km	0.41 Location (556000, 3036500) ROI = 0 km	**0.51** Location (561800, 3029200) ROI = 0 km	0
NO_x	Annual	1	0.032 Location (555500, 3032500) ROI = 0 km	0.032 Location (555500, 3032500) ROI = 0 km	0.034 Location (555500, 3032500) ROI = 0 km	0.036 Location (553500, 3033500) ROI = 0 km	**0.037** Location (555500, 3032500) ROI = 0 km	0
SO_2	Annual	1	0.018 Location (555500, 3032500) ROI = 0 km	0.018 Location (555500, 3032500) ROI = 0 km	0.020 Location (555500, 3032500) ROI = 0 km	**0.021** Location (553500, 3033500) ROI = 0 km	**0.021** Location (555500, 3032500) ROI = 0 km	0
	24-hour	5	0.22 Location (550500, 3028500) ROI = 0 km	0.22 Location (553000, 3036000) ROI = 0 km	0.22 Location (550500, 3041000) ROI = 0 km	0.22 Location (556000, 3036500) ROI = 0 km	**0.28** Location (561800, 3029200) ROI = 0 km	0
	3-hour	25	0.87 Location (549000, 3039000) ROI = 0 km	0.88 Location (549000, 3039000) ROI = 0 km	0.83 Location (548000, 3031000) ROI = 0 km	0.81 Location (569500, 3017000) ROI = 0 km	**1.99** Location (561800, 3029200) ROI = 0 km	0
CO	1-Hour	2000	14.0 Location (561700, 3030400) ROI = 0 km	13.71 Location (558500, 3029500) ROI = 0 km	16.35 Location (562300, 3030200) ROI = 0 km	18.6 Location (562000, 3030300) ROI = 0 km	**51.6** Location (561800, 3029200) ROI = 0 km	0
	8-Hour	500	4.98 Location (559700, 3026400) ROI = 0 km	4.39 Location (544000, 3025000) ROI = 0 km	4.53 Location (558800, 3031800) ROI = 0 km	4.18 Location (549000, 3039000) ROI = 0 km	**7.40** Location (561800, 3029200) ROI = 0 km	0

Notes:
Location = (UTM Coordinates)
Bold indicates maximum value

Table 6-3
Summary of Dispersion Modeling Results
Maximim Predicted Offsite Concentrations and Radii of Significant Impact (60 Percent Load, Natural Gas Firing)
Duke Energy Fort Pierce, LLC
Fort Pierce Generating Facility
Fort Pierce, Florida

Pollutant	Averaging Period	Significant Impact Level (ug/m3)	Maximum Predicted Offsite Concentration (ug/m3) 1987	1988	1989	1990	1991	Maximum Radius of Significant Impact (km)
PM-10	Annual	1	0.037 Location (555500, 3032500) ROI = 0 km	0.037 Location (555500, 3032500) ROI = 0 km	0.039 Location (555500, 3032500) ROI = 0 km	0.042 Location (554500, 3033000) ROI = 0 km	**0.043** Location (555500, 3032500) ROI = 0 km	0
	24-hour	5	0.45 Location (551000, 3028500) ROI = 0 km	0.44 Location (553000, 3036000) ROI = 0 km	0.43 Location (551000, 3040500) ROI = 0 km	0.46 Location (556000, 3036500) ROI = 0 km	**0.54** Location (561800, 3029200) ROI = 0 km	0
NO_X	Annual	1	0.031 Location (555500, 3032500) ROI = 0 km	0.031 Location (555500, 3032500) ROI = 0 km	0.033 Location (555500, 3032500) ROI = 0 km	0.035 Location (554500, 3033000) ROI = 0 km	**0.036** Location (555500, 3032500) ROI = 0 km	0
SO_2	Annual	1	0.017 Location (555500, 3032500) ROI = 0 km	0.017 Location (555500, 3032500) ROI = 0 km	0.018 Location (555500, 3032500) ROI = 0 km	0.019 Location (554500, 3033000) ROI = 0 km	**0.020** Location (555500, 3032500) ROI = 0 km	0
	24-hour	5	0.21 Location (551000, 3028500) ROI = 0 km	0.20 Location (553000, 3036000) ROI = 0 km	0.20 Location (551000, 3040500) ROI = 0 km	0.21 Location (556000, 3036500) ROI = 0 km	**0.25** Location (561800, 3029200) ROI = 0 km	0
	3-hour	25	0.80 Location (561800, 3029100) ROI = 0 km	0.79 Location (549000, 3039000) ROI = 0 km	0.74 Location (548000, 3031000) ROI = 0 km	0.73 Location (569500, 3017000) ROI = 0 km	**1.78** Location (561800, 3029200) ROI = 0 km	0
CO	1-Hour	2000	18.6 Location (561800, 3029100) ROI = 0 km	10.4 Location (561500, 3030600) ROI = 0 km	12.5 Location (562300, 3030200) ROI = 0 km	14.1 Location (562000, 3030300) ROI = 0 km	**41.7** Location (561800, 3029200) ROI = 0 km	0
	8-Hour	500	4.09 Location (559800, 3026500) ROI = 0 km	**3.75** Location (557000, 3028250) ROI = 0 km	3.64 Location (558900, 3031700) ROI = 0 km	3.38 Location (551000, 3037500) ROI = 0 km	5.98 Location (561800, 3029200) ROI = 0 km	0

Notes:
Location = (UTM Coordinates)
Bold indicates maximum value

Table 6-4
Summary of Dispersion Modeling Results
Maximim Predicted Offsite Concentrations and Radii of Significant Impact (Maximum Load, Oil Firing)
Duke Energy Fort Pierce, LLC
Fort Pierce Generating Facility
Fort Pierce, Florida

Pollutant	Averaging Period	Significant Impact Level (ug/m3)	Maximum Predicted Offsite Concentration (ug/m3) 1987	1988	1989	1990	1991	Maximum Radius of Significant Impact (km)
PM-10	Annual	1	0.061 Location (554500, 3033000) ROI = 0 km	0.063 Location (554500, 3033000) ROI = 0 km	0.066 Location (553500, 3033500) ROI = 0 km	0.069 Location (553500, 3033500) ROI = 0 km	**0.071** Location (554000, 3033000) ROI = 0 km	0
	24-hour	5	0.78 Location (552000, 3037000) ROI = 0 km	0.76 Location (543000, 3032000) ROI = 0 km	0.76 Location (549500, 3025500) ROI = 0 km	0.78 Location (550000, 3036000) ROI = 0 km	**0.79** Location (552000, 3033000) ROI = 0 km	0
NO_X	Annual	1	0.048 Location (554500, 3033000) ROI = 0 km	0.050 Location (554500, 3033000) ROI = 0 km	0.053 Location (553500, 3033500) ROI = 0 km	0.055 Location (553500, 3033500) ROI = 0 km	**0.057** Location (554000, 3033000) ROI = 0 km	0
SO_2	Annual	1	0.14 Location (554500, 3033000) ROI = 0 km	0.14 Location (554500, 3033000) ROI = 0 km	0.15 Location (553500, 3033500) ROI = 0 km	**0.15** Location (553500, 3033500) ROI = 0 km	**0.16** Location (554000, 3033000) ROI = 0 km	0
	24-hour	5	1.73 Location (552000, 3037000) ROI = 0 km	1.69 Location (543000, 3032000) ROI = 0 km	1.70 Location (549500, 3025500) ROI = 0 km	1.75 Location (550000, 3036000) ROI = 0 km	**1.77** Location (552000, 3033000) ROI = 0 km	0
	3-hour	25	6.99 Location (545000, 3039000) ROI = 0 km	7.01 Location (549000, 3039000) ROI = 0 km	7.14 Location (563000, 3022750) ROI = 0 km	6.47 Location (572000, 3013000) ROI = 0 km	**7.16** Location (568000, 3012000) ROI = 0 km	0
CO	1-Hour	2000	12.1 Location (561700, 3030500) ROI = 0 km	11.8 Location (561500, 3030600) ROI = 0 km	14.3 Location (562300, 3030300) ROI = 0 km	13.7 Location (562900, 3029600) ROI = 0 km	**14.6** Location (561500, 3030400) ROI = 0 km	0
	8-Hour	500	**3.54** Location (559500, 3026100) ROI = 0 km	3.36 Location (544000, 3025000) ROI = 0 km	3.26 Location (572000, 3014000) ROI = 0 km	3.11 Location (548000, 3040000) ROI = 0 km	3.13 Location (557000, 3032500) ROI = 0 km	0

Notes:
Location = (UTM Coordinates)
Bold indicates maximum value

Table 6-5
Summary of Dispersion Modeling Results
Maximim Predicted Offsite Concentrations and Radii of Significant Impact (75 Percent Load, Oil Firing)
Duke Energy Fort Pierce, LLC
Fort Pierce Generating Facility
Fort Pierce, Florida

Pollutant	Averaging Period	Significant Impact Level (ug/m3)	Maximum Predicted Offsite Concentration (ug/m3) 1987	1988	1989	1990	1991	Maximum Radius of Significant Impact (km)
PM-10	Annual	1	0.075 Location (555500, 3032500) ROI = 0 km	0.076 Location (554000, 3033000) ROI = 0 km	0.080 Location (555500, 3032500) ROI = 0 km	0.085 Location (553500, 3033500) ROI = 0 km	**0.087** Location (555500, 3032500) ROI = 0 km	0
	24-hour	5	0.91 Location (550500, 3028500) ROI = 0 km	0.92 Location (553000, 3036000) ROI = 0 km	0.89 Location (550500, 3041000) ROI = 0 km	0.91 Location (556000, 3036500) ROI = 0 km	**1.01** Location (553000, 3032500) ROI = 0 km	0
NO_x	Annual	1	0.049 Location (555500, 3032500) ROI = 0 km	0.049 Location (555500, 3032500) ROI = 0 km	0.052 Location (555500, 3032500) ROI = 0 km	0.056 Location (553500, 3033500) ROI = 0 km	**0.057** Location (555500, 3032500) ROI = 0 km	0
SO_2	Annual	1	0.14 Location (555500, 3032500) ROI = 0 km	0.14 Location (555500, 3032500) ROI = 0 km	0.15 Location (555500, 3032500) ROI = 0 km	**0.16** Location (553500, 3033500) ROI = 0 km	**0.16** Location (555500, 3032500) ROI = 0 km	0
	24-hour	5	1.67 Location (550500, 3028500) ROI = 0 km	1.69 Location (553000, 3036000) ROI = 0 km	1.64 Location (550500, 3041000) ROI = 0 km	1.67 Location (556000, 3036500) ROI = 0 km	**1.86** Location (561800, 3029200) ROI = 0 km	0
	3-hour	25	6.58 Location (549000, 3039000) ROI = 0 km	6.66 Location (549000, 3039000) ROI = 0 km	6.27 Location (548000, 3031000) ROI = 0 km	6.15 Location (569500, 3017000) ROI = 0 km	**8.89** Location (563000, 3029400) ROI = 0 km	0
CO	1-Hour	2000	9.64 Location (561700, 3030500) ROI = 0 km	9.49 Location (558500, 3029500) ROI = 0 km	11.3 Location (562300, 3030200) ROI = 0 km	12.9 Location (562000, 3030300) ROI = 0 km	**13.5** Location (561400, 3030300) ROI = 0 km	0
	8-Hour	500	**3.40** Location (559700, 3026400) ROI = 0 km	3.02 Location (544000, 3025000) ROI = 0 km	3.11 Location (558800, 3031800) ROI = 0 km	2.86 Location (549000, 3039000) ROI = 0 km	2.88 Location (557750, 3032000) ROI = 0 km	0

Notes:
Location = (UTM Coordinates)
Bold indicates maximum value

Table 6-6
Summary of Dispersion Modeling Results
Maximim Predicted Concentrations and Radii of Significant Impact (60 Percent Load, Oil Firing)
Duke Energy Fort Pierce, LLC
Fort Pierce Generating Facility
Fort Pierce, Florida

Pollutant	Averaging Period	Significant Impact Level (ug/m3)	Maximum Predicted Offsite Concentration (ug/m3) 1987	1988	1989	1990	1991	Maximum Radius of Significant Impact (km)
PM-10	Annual	1	0.080 Location (555500, 3032500) ROI = 0 km	0.081 Location (555500, 3032500) ROI = 0 km	0.085 Location (555000, 3032500) ROI = 0 km	0.091 Location (554500, 3033000) ROI = 0 km	**0.093** Location (555000, 3032500) ROI = 0 km	0
	24-hour	5	0.98 Location (551000, 3028500) ROI = 0 km	0.96 Location (553000, 3036000) ROI = 0 km	0.94 Location (551000, 3040500) ROI = 0 km	0.98 Location (556000, 3036500) ROI = 0 km	**1.18** Location (561800, 3029200) ROI = 0 km	0
NO_x	Annual	1	0.048 Location (555500, 3032500) ROI = 0 km	0.048 Location (555500, 3032500) ROI = 0 km	0.051 Location (555000, 3032500) ROI = 0 km	0.055 Location (554500, 3033000) ROI = 0 km	**0.056** Location (555000, 3032500) ROI = 0 km	0
SO_2	Annual	1	0.13 Location (555500, 3032500) ROI = 0 km	0.13 Location (555500, 3032500) ROI = 0 km	0.14 Location (555000, 3032500) ROI = 0 km	0.15 Location (554500, 3033000) ROI = 0 km	**0.16** Location (555500, 3032500) ROI = 0 km	0
	24-hour	5	1.63 Location (551000, 3028500) ROI = 0 km	1.59 Location (553000, 3036000) ROI = 0 km	1.56 Location (551000, 3040500) ROI = 0 km	1.64 Location (556000, 3036500) ROI = 0 km	**1.96** Location (561800, 3029200) ROI = 0 km	0
	3-hour	25	6.30 Location (561800, 3029100) ROI = 0 km	6.25 Location (549000, 3039000) ROI = 0 km	5.87 Location (548000, 3031000) ROI = 0 km	5.77 Location (569500, 3017000) ROI = 0 km	**14.1** Location (561800, 3029200) ROI = 0 km	0
CO	1-Hour	2000	15.1 Location (561800, 3029100) ROI = 0 km	8.49 Location (561500, 3030600) ROI = 0 km	10.2 Location (562300, 3030200) ROI = 0 km	11.6 Location (562000, 3030300) ROI = 0 km	**33.9** Location (561800, 3029200) ROI = 0 km	0
	8-Hour	500	3.33 Location (559800, 3026500) ROI = 0 km	3.06 Location (557000, 3028250) ROI = 0 km	2.96 Location (558900, 3031700) ROI = 0 km	2.75 Location (551000, 3037500) ROI = 0 km	**4.86** Location (561800, 3029200) ROI = 0 km	0

Notes:
Location = (UTM Coordinates)
Bold indicates maximum value

The proposed Facility is located approximately 360 km south of the Georgia border. Based on the modeling analyses conducted and summarized herein, no significant air quality impacts are expected in Georgia.

6.5.1.2 PSD Class II Increment Consumption

Since the proposed Facility has been shown to have an insignificant impact on ambient air quality at all locations, PSD Class II increment will not be consumed by this project and no additional analysis of PSD Class II increment is required.

6.5.1.3 Compliance with National Ambient Air Quality Standards

Since the emissions of NO_X, SO_2, PM-10, and CO, from the proposed Facility do not result in a significant impact (Section 6.5.1.1), it is not necessary to demonstrate compliance with the NAAQS for these pollutants; however, it is noted that St. Lucie County is considered by FDEP to be in attainment of all ambient air quality standards. Ozone is not an emitted pollutant; rather, it forms as a result of complex chemical reactions between precursor emissions of VOCs and NO_X in the presence of sunlight and higher temperatures, resulting in peak ozone levels occurring at mid-day during the warmest months of the year. The proposed Facility will be a source of both NO_X and VOC emissions; however, the increase in regional emissions is not expected to be significant enough to result in a measurable increase in ozone levels at any downwind location. Furthermore, emissions of NO_X and VOC will be minimized through the use of BACT as described in Section 5.0. St. Lucie County is currently considered to be an attainment for ozone, as previously discussed in Section 4.4.1, based on the most recent three year-period of ambient ozone monitoring data.

6.5.1.5 Impact on PSD Class I Areas

The closest PSD Class I area to the proposed Facility is the Everglades National Park, which is located approximately 190 km southeast of the project site. Since the distance to the Sipsey National Wilderness Area is greater than 100 km, and the predicted impacts on ambient air quality resulting from the operation of the Facility have been shown to be insignificant, no significant impacts (for any pollutant) are expected in this Class I area.

6.5.1.6 Ambient Air Quality Monitoring

The maximum predicted ambient air quality impacts are below *de minimis* impact levels for NO_X, PM-10, SO_2, and CO for all averaging periods. Therefore the proposed Facility is exempt from any preconstruction monitoring requirements for these pollutants. A comparison of maximum predicted impacts and the *de minimis* impact levels is as follows:

Pollutant	Duke Energy Fort Pierce, LLC Maximum Predicted Concentration ($\mu g/m^3$)	EPA De Minimis Impact Level ($\mu g/m^3$)
NO_X (annual)	0.096	14
PM-10 (24-hour)	1.18	10
SO_2 (24-hour)	1.96	13
CO (8-hour)	7.40	575

6.5.2 Air Toxics Impact Assessment

The US EPA's guidance on the assessment of non-regulated "toxic pollutants" requires that permit applicants evaluate emissions of toxic air pollutants, which the proposed Facility could emit in amounts potentially of concern to the public. Additional information is therefore provided on the potential impacts of formaldehyde emissions, as well as an estimate of other emissions (including heavy metals) from the proposed Facility.

6.5.2.1 Formaldehyde Emissions

The estimate of formaldehyde emissions for the proposed Facility was based on the results of formaldehyde stack tests for a similar facility at a recently constructed combustion turbine facility located in the South Coast Air Quality Management District (SCAQMD) of Southern California. The Facility underwent stack testing in 1995 in accordance with California Air Resources Board (CARB) Method 430 testing guidelines for formaldehyde, which consist of three tests, each with a duration of 2 hours. The units tested included two 80 - 100 MW class gas-fired, steam injected, industrial combustion turbines. The Facility in question is equipped with SCR, however, the SCRs were not in operation at the time of the test. Formaldehyde emissions rates obtained during this testing were 0.0000116 lb/MMBtu, based on lower heating value (LHV) fuel input (Unit 1) and 0.0000095 lb/MMBtu (LHV) for Unit 2, which represents an average emissions rate of 0.00001055 lb/MMBtu (LHV). For the proposed Facility, formaldehyde emissions rates based on these test data would be 0.0823 lb/hr (0.0104 g/s), using a facility heat input of 7,800 MMBtu/hr (HHV).

This value is significant because it is non-zero and the USEPA has determined that any emissions of formaldehyde are "significant". Formaldehyde is readily oxidized at combustion turbine temperatures and combustion is an acceptable method for controlling formaldehyde emissions. The proposed Facility will utilize complete combustion as demonstrated in the BACT section of the permit application. Therefore, the BACT for formaldehyde is proposed to be efficient combustion, which is consistent with previous BACT determinations for similar gas turbine installations. No significant ambient air quality impact is expected to occur as a result of this very low emission rate.

6.5.2.2 Other Emissions

The combustion of natural gas and No. 2 low sulfur fuel oil is not expected to result in any significant emissions of lead, beryllium, mercury, fluorides, arsenic, hydrogen sulfide, total reduced sulfur, manganese, nickel, cadmium, chromium, copper, or radionuclides. Of these, six have "significant" emission limits as defined by EPA. These are lead, beryllium, mercury, fluorides, hydrogen sulfide, and total reduced sulfur. Although trace amounts may result from the combustion of natural gas and No. 2 low sulfur fuel oil, EPA has not defined a significance level for benzene, manganese, nickel, chromium, copper, cadmium, or radionuclides. Estimated emissions for HAPs are shown in Tables 6-7 and 6-8 for natural gas firing and fuel oil firing, respectively.

TABLE 6-7
Summary of Air Toxic Emission Factors and Emission Rates (Natural Gas Firing)
Duke Energy Fort Pierce, LLC
Fort Pierce Generating Facility
Fort Pierce, Florida

Pollutant	Emission Factor (lb/mmBtu)	Emission Factor Source	Total Plant Emissions (tons/yr)
Formaldehyde	1.055 E-05	Test Results[a]	0.103
Benzene	1.2 E-05	AP-42	0.117
Acetaldehyde	4.5 E-05	Memorandum[b]	0.439
POM	3.69 E-06	Memorandum[b]	0.036
Acrolein	6.4 E-06	AP-42	0.062
Ethylbenzene	3.2 E-05	AP-42	0.312
Naphthalene	1.3 E-06	AP-42	0.013
PAH	2.2 E-06	AP-42	0.021

TABLE 6-7
Summary of Air Toxic Emission Factors and Emission Rates (Natural Gas Firing)
Duke Energy Fort Pierce, LLC
Fort Pierce Generating Facility
Fort Pierce, Florida

Pollutant	Emission Factor (lb/mmBtu)	Emission Factor Source	Total Plant Emissions (tons/yr)
Toluene	1.3 E-04	AP-42	1.27
Xylene	6.4 E-05	AP-42	0.624

[a]California test results as described in Section 6.5.2.3.
[b]EPA/Sims Memorandum dated 12/30/99.

TABLE 6-8
Summary of Air Toxic Emission Factors and Emission Rates (Fuel Oil Firing)
Duke Energy Fort Pierce, LLC
Fort Pierce Generating Facility
Fort Pierce, Florida

Pollutant	Emission Factor (lb/mmBtu)	Emission Factor Source	Total Plant Emissions (tons/yr)
Acetaldehyde	3.03 E-05	Memorandum[a]	0.124
Benzene	8.30 E-05	Memorandum[a]	0.341
Cadmium	4.80 E-06	Memorandum[a]	0.020
Chromium	1.08 E-05	Memorandum[a]	0.044
Formaldehyde	3.42 E-04	Memorandum[a]	1.40
Lead	1.42 E-05	Memorandum[a]	0.058
Manganese	7.89 E-04	Memorandum[a]	3.24
Mercury	1.20 E-06	Memorandum[a]	0.005
Naphthalene	3.5 E-05	AP-42	0.144
Nickel	5.20 E-05	Memorandum[a]	0.213
PAH	4.0 E-05	AP-42	0.164
POM	8.74 E-05	Memorandum[a]	0.359

[a] EPA/Sims Memorandum dated 12/30/99.

Emissions are estimated using emission factors for natural gas and distillate oil-fired stationary gas turbines found in Supplement F to the Fifth Edition of AP-42 "Compilation of Emission Factors Volume I: Stationary and Area Sources" and an EPA Memorandum authored by Roy Sims (Dated 12/30/99). A copy of the 12/30/99 memo is available on EPA's web site at www.epa.gov./ttn/uatw/combust/turbine/turbpg.html. Emissions are calculated based on a plant heat input of 7,800 MMBtu/hr and 8,208 MMBtu/hr for natural gas and fuel oil, respectively. Total emissions of air toxic pollutants from the Facility indicate that HAP emissions will not trigger a requirement for case-by-case MACT, since no single HAP emission will exceed 10 tons/yr, and total HAPs will be less than 25 tons/yr.

Organic compounds are readily oxidized at combustion turbine temperatures and combustion is an acceptable method for controlling these emissions. The proposed Facility will utilize complete combustion as demonstrated in the BACT section of the permit application. Therefore, BACT is proposed to be efficient combustion, which is consistent with previous BACT determinations for similar gas turbine installations.

7.0 Additional Impact Analyses

As required by PSD regulations, this section addresses possible impacts on visibility, vegetation and soils, growth, PSD Class I areas, and nonattainment areas.

7.1 Effects on Visibility and PSD Class I Areas

The impact on visibility in the nearest PSD Class I area (i.e., the Everglades National Park, 190 km to the Southwest) attributable to the operation of the proposed Facility is not expected to be either significant or measurable. Inasmuch as the increase in emissions associated with the operation of the proposed Facility will result in only an insignificant impact on ambient air quality in the vicinity of the Facility, it is unlikely that the operation of the proposed Facility will cause any impairment to visibility at any location.

7.2 Effects on Vegetation and Soils

One indicator of potential effects to vegetation and soils is a comparison of predicted ambient concentrations with ambient air quality standards. Of most significance here is the fact that the secondary NAAQS were established to prevent adverse "welfare" effects such as direct damage to vegetation and harmful contamination of soils. In light of the fact that it has been shown that the operation of the Facility will not result in a significant impact on air quality at any location, there should not be any discernible effects on vegetation and soils.

7.3 Effects on Associated Growth

Employment at the Facility is expected to total approximately 30 personnel once the Facility becomes operational. No significant impact on local air quality conditions is expected that might otherwise accompany significant population growth. Personnel hired for this project will most likely be drawn from the existing regional population, with no appreciable changes in traffic or other growth associated parameters.

7.4 Impacts on Nonattainment Areas

There are no nonattainment areas for any pollutant in Florida. The Facility is not expected to have a significant impact on any nonattainment area, based on the air quality impact assessment performed.

8 References

U.S. Environmental Protection Agency, 2000. Industrial Source Complex Model, Version 00101. Office of Air Quality Planning and Standards. Available from EPA TTN Electronic Bulletin Board System (919) 541-5742.

U.S. Environmental Protection Agency, 1999. Hazardous Air Pollutant (HAP) Emission Control Technology for New Stationary Combustion Turbines, Docket A-95-51, December 30, 1999.

Appendix A
Permit Application Forms

Department of Environmental Protection

Division of Air Resources Management

APPLICATION FOR AIR PERMIT - TITLE V SOURCE

See Instructions for Form No. 62-210.900(1)

I. APPLICATION INFORMATION

Identification of Facility

1. Facility Owner/Company Name: Duke Energy Fort Pierce, LLC	
2. Site Name: Duke Energy Fort Pierce Generating Station	
3. Facility Identification Number: [X] Unknown	
4. Facility Location: ½ mile east of Florida Turnpike, 1 mile north of Midway Road Street Address or Other Locator: City: Fort Pierce County: St. Lucie Zip Code: 34981	
5. Relocatable Facility? [ ] Yes [X] No	6. Existing Permitted Facility? [ ] Yes [X] No

Application Contact

1. Name and Title of Application Contact: Nathan K. Plagens; Manager, Environmental Services; Duke Energy North America
2. Application Contact Mailing Address: Nathan K. Plagens Organization/Firm: Duke Energy North America Street Address: 5400 Westheimer Court City: Houston State: Texas Zip Code: 77056-5310
3. Application Contact Telephone Numbers: Telephone: (713) 627-5985 Fax: (713)- 627-5644

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	10-5-00
2. Permit Number:	1110100-001-AC
3. PSD Number (if applicable):	PSD-FL-302
4. Siting Number (if applicable):	

Purpose of Application

Air Operation Permit Application

This Application for Air Permit is submitted to obtain: (Check one)

[ ] Initial Title V air operation permit for an existing facility which is classified as a Title V source.

[ ] Initial Title V air operation permit for a facility which, upon start up of one or more newly constructed or modified emissions units addressed in this application, would become classified as a Title V source.

Current construction permit number:______________________________

[ ] Title V air operation permit revision to address one or more newly constructed or modified emissions units addressed in this application.

Current construction permit number:______________________________

Operation permit number to be revised:______________________________

[ ] Title V air operation permit revision or administrative correction to address one or more proposed new or modified emissions units and to be processed concurrently with the air construction permit application. (Also check Air Construction Permit Application below.)

Operation permit number to be revised/corrected:______________________________

[ ] Title V air operation permit revision for reasons other than construction or modification of an emissions unit. Give reason for the revision; e.g., to comply with a new applicable requirement or to request approval of an "Early Reductions" proposal.

Operation permit number to be revised:______________________________

Reason for revision:______________________________

Air Construction Permit Application

This Application for Air Permit is submitted to obtain: (Check one)

[X] Air construction permit to construct or modify one or more emissions units.

[ ] Air construction permit to make federally enforceable an assumed restriction on the potential emissions of one or more existing, permitted emissions units.

[ ] Air construction permit for one or more existing, but unpermitted, emissions units.

Owner/Authorized Representative or Responsible Official

1.	Name and Title of Owner/Authorized Representative or Responsible Official: Steven F. Gilliland, Senior Vice President
2.	Owner/Authorized Representative or Responsible Official Mailing Address: Organization/Firm: Duke Energy North America Street Address: 5400 Westheimer Court City: Houston State: Texas Zip Code: 77056-5310
3.	Owner/Authorized Representative or Responsible Official Telephone Numbers: Telephone: (713) 627-6500 Fax: (713) 627-5644
4.	Owner/Authorized Representative or Responsible Official Statement: *I, the undersigned, am the owner or authorized representative*(check here [ ], if so) or the responsible official (check here [X], if so) of the Title V source addressed in this application, whichever is applicable. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof. I understand that a permit, if granted by the Department, cannot be transferred without authorization from the Department, and I will promptly notify the Department upon sale or legal transfer of any permitted emissions unit.* Signature 9/18/00 Date

* Attach letter of authorization if not currently on file.

Professional Engineer Certification

1.	Professional Engineer Name: Pamela A. Lehr, P.E. Registration Number: 042634
2.	Professional Engineer Mailing Address: Organization/Firm: CH2M HILL Street Address: 800 Fairway Dr., Suite 350 City: Deerfield Beach State: FL Zip Code: 33441
3.	Professional Engineer Telephone Numbers: Telephone: (954) 426-4008 Fax: (954) 698-6010

4. Professional Engineer Statement:

I, the undersigned, hereby certify, except as particularly noted herein, that:*

(1) To the best of my knowledge, there is reasonable assurance that the air pollutant emissions unit(s) and the air pollution control equipment described in this Application for Air Permit, when properly operated and maintained, will comply with all applicable standards for control of air pollutant emissions found in the Florida Statutes and rules of the Department of Environmental Protection; and

(2) To the best of my knowledge, any emission estimates reported or relied on in this application are true, accurate, and complete and are either based upon reasonable techniques available for calculating emissions or, for emission estimates of hazardous air pollutants not regulated for an emissions unit addressed in this application, based solely upon the materials, information and calculations submitted with this application.

If the purpose of this application is to obtain a Title V source air operation permit (check here [ ], if so), I further certify that each emissions unit described in this Application for Air Permit, when properly operated and maintained, will comply with the applicable requirements identified in this application to which the unit is subject, except those emissions units for which a compliance schedule is submitted with this application.

If the purpose of this application is to obtain an air construction permit for one or more proposed new or modified emissions units (check here [X], if so), I further certify that the engineering features of each such emissions unit described in this application have been designed or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles applicable to the control of emissions of the air pollutants characterized in this application.

If the purpose of this application is to obtain an initial air operation permit or operation permit revision for one or more newly constructed or modified emissions units (check here [ ], if so), I further certify that, with the exception of any changes detailed as part of this application, each such emissions unit has been constructed or modified in substantial accordance with the information given in the corresponding application for air construction permit and with all provisions contained in such permit.

Pamela A Peters

Signature

August 25, 2000

Date

(seal)

* Attach any exception to certification statement.

Scope of Application

Emissions Unit ID	Description of Emissions Unit	Permit Type	Processing Fee
CTG-1 – CTG-8	Combustion Turbines (8 identical units)	AC1A	$7,500

Application Processing Fee

Check one: [X] Attached - Amount: $7,500 [ ] Not Applicable

Construction/Modification Information

1. Description of Proposed Project or Alterations: Duke Energy Fort Pierce, LLC (Duke) proposes to construct and operate a power generating facility near the City of Fort Pierce, Florida (the Facility) in St. Lucie County. The Facility will be known as the Fort Pierce Generating Station and will utilize eight simple cycle generating units to produce up to 640 MW of peak power at its design operating conditions. The Facility will be permitted to operate each of the turbines up to 2,500 hours per year, or 20,000 hours per year for all units combined, whichever is less restrictive. The primary fuel used by the turbines will be natural gas, with the capability of using ultra low sulfur (0.05 percent) No. 2 distillate fuel oil as a backup fuel in the unlikely event of a natural gas curtailment. Fuel oil use will be limited to 1,000 hours per turbine per year.
2. Projected or Actual Date of Commencement of Construction: May 2001
3. Projected Date of Completion of Construction: June 2002

Application Comment

Additional information relative to the proposed project is provided by the in a document entitled "Application for Permit to Construct Air Emissions Equipment", in which this application is included as an Appendix.

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates: Zone: 17 East (km): 561.591 North (km): 3028.963			
2. Facility Latitude/Longitude: Latitude (DD/MM/SS): Longitude (DD/MM/SS):			
3. Governmental Facility Code: 0	4. Facility Status Code: C	5. Facility Major Group SIC Code: 49	6. Facility SIC(s): 4911
7. Facility Comment (limit to 500 characters):			

Facility Contact

1. Name and Title of Facility Contact: Nathan K. Plagens, Manager, Environmental Services, Duke Energy North America.
2. Facility Contact Mailing Address: Organization/Firm: Duke Energy North America Street Address: 5400 Westheimer Court City: Houston State: Texas Zip Code: 77056-5310
3. Facility Contact Telephone Numbers: Telephone: (713)-627-5985 Fax: (713)-627-5644

Facility Regulatory Classifications

Check all that apply:

1. [ ] Small Business Stationary Source?	[ ] Unknown
2. [X] Major Source of Pollutants Other than Hazardous Air Pollutants (HAPs)?	
3. [ ] Synthetic Minor Source of Pollutants Other than HAPs?	
4. [ ] Major Source of Hazardous Air Pollutants (HAPs)?	
5. [ ] Synthetic Minor Source of HAPs?	
6. [X] One or More Emissions Units Subject to NSPS?	
7. [ ] One or More Emission Units Subject to NESHAP?	
8. [X] Title V Source by EPA Designation?	
9. Facility Regulatory Classifications Comment (limit to 200 characters):	

List of Applicable Regulations

See Section 4.0 of attached PSD Permit Application Report	

B. FACILITY POLLUTANTS

List of Pollutants Emitted

1. Pollutant Emitted	2. Pollutant Classif.	3. Requested Emissions Cap lb/hour	tons/year	4. Basis for Emissions Cap	5. Pollutant Comment
NO_X	A				
PM10	A				
SO_2	A				
CO	A				
VOC	SM				

C. FACILITY SUPPLEMENTAL INFORMATION

Supplemental Requirements

1. Area Map Showing Facility Location: [X] Attached, Document ID: Figure 2-1 [ ] Not Applicable [ ] Waiver Requested
2. Facility Plot Plan: [X] Attached, Document ID: Figure 2-2 [ ] Not Applicable [ ] Waiver Requested
3. Process Flow Diagram(s): [X] Attached, Document ID: Figure 2-4 [ ] Not Applicable [ ] Waiver Requested
4. Precautions to Prevent Emissions of Unconfined Particulate Matter: [ ] Attached, Document ID:_______ [X] Not Applicable [ ] Waiver Requested
5. Fugitive Emissions Identification: [ ] Attached, Document ID:_______ [X] Not Applicable [ ] Waiver Requested
6. Supplemental Information for Construction Permit Application: [X] Attached, Document ID: PSD Application Report [ ] Not Applicable
7. Supplemental Requirements Comment: Supplemental information is provided in the attached "Application for Permit to Construct Air Emissions Equipment" submitted in September of 2000, and in which this application is included as an appendix.

Additional Supplemental Requirements for Title V Air Operation Permit Applications

8. List of Proposed Insignificant Activities: [ ] Attached, Document ID:________ [X] Not Applicable
9. List of Equipment/Activities Regulated under Title VI: [ ] Attached, Document ID:________ [ ] Equipment/Activities On site but Not Required to be Individually Listed [X] Not Applicable
10. Alternative Methods of Operation: [ ] Attached, Document ID:________ [X] Not Applicable
11. Alternative Modes of Operation (Emissions Trading): [ ] Attached, Document ID:________ [X] Not Applicable
12. Identification of Additional Applicable Requirements: [ ] Attached, Document ID:________ [X] Not Applicable
13. Risk Management Plan Verification: [ ] Plan previously submitted to Chemical Emergency Preparedness and Prevention Office (CEPPO). Verification of submittal attached (Document ID:________) or previously submitted to DEP (Date and DEP Office:____________________) [ ] Plan to be submitted to CEPPO (Date required:____________________) [X] Not Applicable
14. Compliance Report and Plan: [ ] Attached, Document ID:________ [X] Not Applicable
15. Compliance Certification (Hard-copy Required): [ ] Attached, Document ID:________ [X] Not Applicable

III. EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through J as required) must be completed for each emissions unit addressed in this Application for Air Permit. If submitting the application form in hard copy, indicate, in the space provided at the top of each page, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application.

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in This Section: (Check one)

[X] This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Regulated or Unregulated Emissions Unit? (Check one)

[X] The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

[ ] The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

3. Description of Emissions Unit Addressed in This Section (limit to 60 characters): 80 MW simple cycle combustion turbine generating units 1 through 8 (8 identical units)

4. Emissions Unit Identification Number:
ID:

[X] No ID
[ ] ID Unknown

5. Emissions Unit Status Code: C	6. Initial Startup Date: 6/2002	7. Emissions Unit Major Group SIC Code: 4911	8. Acid Rain Unit? [X]

9. Emissions Unit Comment: (Limit to 500 Characters) Eight identical simple cycle generating units that will be fired on natural gas as a primary fuel for up to 2,500 hours/year (maximum average annual hours per unit), with distillate fuel oil as a backup fuel for up to 1,000 hours/year (maximum average annual hours per unit).

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method): Proposed controls are described in the attached PSD Permit Application Report. NO_X Emissions will be controlled by utilizing dry low NO_X combustors (gas and oil firing), as well as water injection during periods of oil firing; clean burning pipeline natural gas and low sulfur, low ash fuel oil for the control of SO_2 and PM10 emissions; good operating practices for CO and VOC emission control.
2. Control Device or Method Code(s): 024, 028, 030

Emissions Unit Details

1. Package Unit: Manufacturer: General Electric		Model Number: 7EA
2. Generator Nameplate Rating:	80 MW	
3. Incinerator Information: Dwell Temperature:		°F
Dwell Time:		seconds
Incinerator Afterburner Temperature:		°F

B. EMISSIONS UNIT CAPACITY INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Operating Capacity and Schedule

1. Maximum Heat Input Rate:	975 mmBtu/hr (gas), 1026 mmBtu/hr (oil) (HHV) 878 mmBtu/hr (gas), 925 mmBtu/hr (oil) (LHV)	
2. Maximum Incineration Rate:	lb/hr	tons/day
3. Maximum Process or Throughput Rate:		
4. Maximum Production Rate: 80 MW per turbine (8 identical)		
5. Requested Maximum Operating Schedule:	24 hours/day 52 weeks/year	7 days/week 2,500 hours/year
6. Operating Capacity/Schedule Comment (limit to 200 characters): To be operated as a fully dispatchable peak power generating facility, up to 20,000 hours per year for all eight units combined (i.e., an average of 2,500 hours per year per unit). If natural gas is not available, each turbine could operate (on average) up to 1,000 hours/yr on backup fuel oil (i.e., 8,000 hours per year for all eight units combined). Production rate and heat inputs are based on average ambient temperature conditions.		

Emissions Unit Information Section ______ of ______

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

See Section 4.0 of attached PSD Permit Application Report	

D. EMISSION POINT (STACK/VENT) INFORMATION
(Regulated Emissions Units Only)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram? CTG-1 – CTG-8	2. Emission Point Type Code: 1
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point): Not Applicable	
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:	

5. Discharge Type Code: V	6. Stack Height: 93 feet	7. Exit Diameter: 15 feet
8. Exit Temperature: 1005 °F	9. Actual Volumetric Flow Rate: 1,456,800 acfm	10. Water Vapor: 9 %

11. Maximum Dry Standard Flow Rate: 477,790 dscfm	12. Nonstack Emission Point Height: feet

13. Emission Point UTM Coordinates:

Zone: 17 East (km): 561.591 North (km): 3028.963

14. Emission Point Comment: Exit temperature and volumetric flow rate based on average ambient temperature conditions.

E. SEGMENT (PROCESS/FUEL) INFORMATION
(All Emissions Units)

Segment Description and Rate: Segment __1__ of __2__

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Natural gas** fired in combustion turbines		
2. Source Classification Code (SCC): 20100201	3. SCC Units: Million Cubic Feet Burned	
4. Maximum Hourly Rate: 0.975	5. Maximum Annual Rate: 2437.5	6. Estimated Annual Activity Factor: N/A
7. Maximum % Sulfur: Negligible	8. Maximum % Ash: Negligible	9. Million Btu per SCC Unit: 1,000
10. Segment Comment (limit to 200 characters): Calculations based on 1,000 Btu per cubic foot of natural gas and HHV heat input of 975 mmBtu/hr. Maximum annual heat input is based on 2,500 hours/year operation. Information provided is per turbine.		

Segment Description and Rate: Segment __2__ of __2__

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Fuel oil** firing in combustion turbines		
2. Source Classification Code (SCC): 20100101	3. SCC Units: Thousand Gallons Burned	
4. Maximum Hourly Rate: 8.085	5. Maximum Annual Rate: 8,085	6. Estimated Annual Activity Factor: N/A
7. Maximum % Sulfur: 0.05	8. Maximum % Ash: Negligible	9. Million Btu per SCC Unit: 126.9
10. Segment Comment (limit to 200 characters): Calculations based on 1026 mmBtu/hr heat input (HHV), 18,000 Btu/lb of fuel oil, 7.05 lb/gallon of fuel oil. Maximum annual heat input is based on 1,000 hours/year operation. Information provided is per turbine.		

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
NO_X	**024 (Gas + Oil)**	**028 (Oil)**	**EL**
PM10	**0**	**0**	**EL**
SO_2	**0**	**0**	**EL**
CO	**0**	**0**	**EL**
VOC	**0**	**0**	**EL**

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units: CTG-1 – CTG-8 [8 identical]
Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions **Note: Emissions are per Turbine (8 Identical)**

1. Pollutant Emitted: NO_X	2. Total Percent Efficiency of Control: N/A
3. Potential Emissions: 182 lb/hour 126.25 tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 _____ to _____ tons/year	
6. Emission Factor: 42 ppm Reference: Manufacturer guarantee	7. Emissions Method Code: 1
8. Calculation of Emissions (limit to 600 characters): Potential hourly NO_X emissions are based on maximum load, 27 °F, and a manufacturer's guarantee of 42 ppmvd (at 15 percent O_2) as shown in Table 3-4 of PSD Permit Application Report. Potential annual emissions are based on 2,500 hours/year operation, with 1,500 hours/year gas firing (at 12.0 ppmvd, 27 °F) and 1,000 hours/year oil firing (at 42 ppmvd, 27 °F). Total potential annual NO_X emissions <u>for all 8 units combined</u> are 1,010 tons/year.	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions __1__ of __2__

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions: June 2002
3. Requested Allowable Emissions and Units: 12.0 ppmvd (at 15 percent O_2)	4. Equivalent Allowable Emissions: 47 lb/hour 58.75 tons/year
5. Method of Compliance (limit to 60 characters): Stack testing and/or continuous monitoring as required by 40 CFR 60, Subpart GG and 40 CFR 75.	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): Hourly NO_X emissions based on maximum load, **GAS FIRED OPERATION**, 27 °F. Annual NO_X emissions are based on 2,500 hours/yr operation, 27 °F, as shown in Table 3-1 of PSD Application. Total allowable annual emissions <u>for all 8 units combined</u> is 470 tons/yr.	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions: June 2002
3. Requested Allowable Emissions and Units: 42 ppmvd (at 15 percent O_2)	4. Equivalent Allowable Emissions: 182 lb/hour 91.0 tons/year
5. Method of Compliance (limit to 60 characters): Stack testing and/or continuous monitoring as required by 40 CFR 60, Subpart GG and 40 CFR 75	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): Hourly NO_X emissions based on maximum load, **OIL FIRED OPERATION**, 27 °F. Annual NO_X emissions are based on 1,000 hours/yr operation, 27 °F, as shown in Table 3-4 of PSD Application. Total allowable annual emissions for all 8 units combined is 728 tons/yr.	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - : CTG-1 – CTG-8 [8 identical]
Emissions-Limited and Preconstruction Review Pollutants Only)

<u>Potential/Fugitive Emissions</u> **Note: Emissions are Per Turbine (8 Identical)**

1. Pollutant Emitted: SO_2	2. Total Percent Efficiency of Control: N/A
3. Potential Emissions: 58 lb/hour 34.25 tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 _____ to _____ tons/year	
6. Emission Factor: Sulfur content of fuel Reference: Fuel specification	7. Emissions Method Code: 2
8. Calculation of Emissions (limit to 600 characters): Potential hourly SO_2 emissions are based on maximum load, 27 °F, and the sulfur content of the fuel oil burned as shown in Table 3-4 of the PSD Permit Application Report. Potential annual emissions are based on 2,500 hours/year operation, with 1,500 hours/year gas firing (at 2 grains sulfur per 100 SCF gas burned, 27 °F) and 1,000 hours/year oil firing (at 0.05% Sulfur, 27 °F), as shown in Tables 3-1 and 3-4 of the PSD Permit Application. Total potential annual SO_2 emissions <u>for all 8 units combined</u> are 274 tons/year.	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

<u>**Allowable Emissions**</u> Allowable Emissions __1__ of __2__

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions: June 2002
3. Requested Allowable Emissions and Units: 0.01 lb/mmBtu (LHV)	4. Equivalent Allowable Emissions: 7 lb/hour 8.75 tons/year
5. Method of Compliance (limit to 60 characters): Fuel monitoring in accordance with 40 CFR 60 Subparts Dc and GG	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): Hourly SO_2 emissions based on maximum load, **GAS FIRED OPERATION**, 27 °F. Annual SO_2 emissions are based on 2,500 hours/yr operation, 27 °F, as shown in Table 3-1 of PSD Application. Total allowable annual emissions <u>for all 8 units combined</u> is 70 tons/yr.	

Emissions Unit Information Section ______ of ______

<u>Allowable Emissions</u> Allowable Emissions __2___ of __2___

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions: June 2002
3. Requested Allowable Emissions and Units: 0.06 lb/mmBtu (LHV)	4. Equivalent Allowable Emissions: 58 lb/hour 29 tons/year
5. Method of Compliance (limit to 60 characters): Fuel monitoring in accordance with 40 CFR 60 Subparts Dc and GG	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): Hourly SO_2 emissions based on maximum load, **OIL FIRED OPERATION**, 27 °F. Annual emissions are based on 1,000 hours/yr operation, 27 °F, as shown in Table 3-4 of PSD Application. Total allowable annual emissions <u>for all 8 units combined</u> is 232 tons/yr.	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - CTG-1 – CTG-8 [8 identical]
Emissions-Limited and Preconstruction Review Pollutants Only)

<u>Potential/Fugitive Emissions</u> **Note: Emissions are Per Turbine (8 Identical)**

1. Pollutant Emitted: PM10	2. Total Percent Efficiency of Control: N/A
3. Potential Emissions: 26.0 lb/hour 21.25 tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: 0.028 lb/mmBtu Reference: Manufacturer guarantee	7. Emissions Method Code: 1
8. Calculation of Emissions (limit to 600 characters): Potential hourly PM10 emissions are based on maximum load, 27 °F, and the manufacturer's recommendations, as shown in Table 3-4 of the PSD Permit Application Report. Potential annual emissions are based on 2,500 hours/year operation, with 1,500 hours/year gas firing (11.0 lb/hr at 27 °F) and 1,000 hours/year oil firing (26.0 lb/hr at 27 °F), as shown in Tables 3-1 and 3-4. Total potential annual PM10 emissions <u>for all 8 units combined</u> are 170 tons/year.	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

<u>Allowable Emissions</u> Allowable Emissions __1__ of __2__

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions: June 2002
3. Requested Allowable Emissions and Units: 0.013 lb/mmBtu (LHV)	4. Equivalent Allowable Emissions: 11.0 lb/hour 13.75 tons/year
5. Method of Compliance (limit to 60 characters): Stack testing and/or visible emissions monitoring as required by 40 CFR Part 60	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): Hourly PM10 emissions based on maximum load, **GAS-FIRED OPERATION**, 27 °F. Annual PM10 emissions are based on 2,500 hours/yr operation, 27 °F, as shown in Table 3-1 of PSD Application. Total allowable annual emissions <u>for all 8 units combined</u> is 110 tons/yr.	

<u>Allowable Emissions</u> Allowable Emissions __2__ of __2__

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions: June 2002
3. Requested Allowable Emissions and Units: 0.028 lb/mmBtu	4. Equivalent Allowable Emissions: 26.0 lb/hour 13.0 tons/year
5. Method of Compliance (limit to 60 characters): Stack testing and/or visible emissions monitoring as required by 40 CFR Part 60	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): Hourly PM10 emissions based on maximum load, **OIL FIRED OPERATION**, 27 °F. Annual PM10 emissions are based on 1,000 hours/yr operation, 27 °F, as shown in Table 3-4 of PSD Application. Total allowable annual emissions <u>for all 8 units combined</u> is 104 tons/yr.	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - CTG-1 – CTG-8 [8 identical]
Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions **Note: Emissions are Per Turbine (8 Identical)**

1. Pollutant Emitted: CO	2. Total Percent Efficiency of Control: N/A
3. Potential Emissions: 58 lb/hour 72.5 tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: 25 ppm Reference: Manufacturer guarantee	7. Emissions Method Code: 1
8. Calculation of Emissions (limit to 600 characters): Potential hourly CO emissions are based on maximum gas-fired operation, 27 °F, and the manufacturer's recommendations, as shown in Table 3-1 of the PSD Permit Application Report. Potential annual emissions are based on 2,500 hours/year gas-fired operation (58.0 lb/hr at 27 °F), as shown in Table 3-1. Total potential annual CO emissions for all 8 units combined are 580 tons/year.	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions: June 2002
3. Requested Allowable Emissions and Units: 25 ppm	4. Equivalent Allowable Emissions: 58.0 lb/hour 72.5 tons/year
5. Method of Compliance (limit to 60 characters): Initial compliance test and periodic testing as required by DEP	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): Hourly CO emissions based on maximum load, **GAS FIRED OPERATION**, 27 °F. Annual CO emissions are based on 2,500 hours/yr operation, 27 °F, as shown in Table 3-1 of PSD Application. Total allowable annual emissions for all 8 units combined is 580 tons/yr.	

Emissions Unit Information Section _____ of _____

Allowable Emissions Allowable Emissions __2____ of __2____

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions: June 2002
3. Requested Allowable Emissions and Units: 20 ppm	4. Equivalent Allowable Emissions: 47.0 lb/hour 23.5 tons/year
5. Method of Compliance (limit to 60 characters): Initial compliance test and periodic testing as required by DEP	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): Hourly CO emissions based on maximum load, **OIL-FIRED OPERATION**, 27 °F. Annual CO emissions are based on 1,000 hours/yr operation, 27 °F, as shown in Table 3-4 of PSD Application. Total allowable annual emissions for all 8 units combined is 188 tons/yr.	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION

**(Regulated Emissions Units - CTG-1 – CTG-8 [8 identical]
Emissions-Limited and Preconstruction Review Pollutants Only)**

Potential/Fugitive Emissions **Note: Emissions are Per Turbine (8 Identical)**

1. Pollutant Emitted: VOC	2. Total Percent Efficiency of Control: N/A
3. Potential Emissions: 5.0 lb/hour 4.0 tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 _____ to _____ tons/year	
6. Emission Factor: 3.5 ppm Reference: Manufacturer guarantee	7. Emissions Method Code: 1
8. Calculation of Emissions (limit to 600 characters): Potential hourly VOC emissions are based on maximum load, 27 °F, oil-fired operation, and the manufacturer's recommendations, as shown in Table 3-4 of the PSD Permit Application Report. Potential annual emissions are based on 2,500 hours/year operation, with 1,500 hours/year gas firing (2.0 lb/hr at 27 °F) and 1,000 hours/year oil firing (5.0 lb/hr at 27 °F), as shown in Tables 3-1 and 3-4. Total potential annual VOC emissions <u>for all 8 units combined</u> are 32.0 tons/year.	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions __1__ of __2__

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions: June 2002
3. Requested Allowable Emissions and Units: 1.4 ppm	4. Equivalent Allowable Emissions: 2.0 lb/hour 2.5 tons/year
5. Method of Compliance (limit to 60 characters): Initial compliance test and the use of CO emissions as a surrogate for VOC	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): Hourly VOC emissions based on maximum load, **GAS-FIRED OPERATION**, 27 °F. Annual VOC emissions are based on 2,500 hours/yr operation, 27 °F, as shown in Table 3-1 of PSD Application. Total allowable annual emissions <u>for all 8 units combined</u> is 20 tons/yr.	

Emissions Unit Information Section ______ of ______

Allowable Emissions Allowable Emissions __2__ of __2__

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions: June 2002
3. Requested Allowable Emissions and Units: 3.5 ppm	4. Equivalent Allowable Emissions: 5.0 lb/hour 2.5 tons/year
5. Method of Compliance (limit to 60 characters): Initial compliance test and use of CO emissions limit as a surrogate for VOC	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): Hourly VOC emissions based on maximum load, **OIL-FIRED OPERATION**, 27 °F. Annual VOC emissions are based on 1,000 hours/yr operation, 27 °F, as shown in Table 3-4 of PSD Application. Total allowable annual emissions for all 8 units combined is 20 tons/yr.	

H. VISIBLE EMISSIONS INFORMATION
(Only Regulated Emissions Units Subject to a VE Limitation)

Visible Emissions Limitation: Visible Emissions Limitation _____ of _____

1. Visible Emissions Subtype: VE10	2. Basis for Allowable Opacity: [X] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: 10 % Exceptional Conditions: 10 % Maximum Period of Excess Opacity Allowed: 0 min/hour	
4. Method of Compliance: Periodic visual observation using EPA Reference Method 9 as required by DEP	
5. Visible Emissions Comment (limit to 200 characters):	

I. CONTINUOUS MONITOR INFORMATION
(Only Regulated Emissions Units Subject to Continuous Monitoring)

Continuous Monitoring System: Continuous Monitor _____ of _____

1. Parameter Code: EM	2. Pollutant(s): NO_X
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: To be determined Manufacturer: To be determined Model Number: To be determined	Serial Number:
5. Installation Date: To be determined	6. Performance Specification Test Date: To be determined
7. Continuous Monitor Comment (limit to 200 characters): CEM system for NO_X monitoring to be installed and operated in conformance with 40 CFR Subpart 75.	

J. EMISSIONS UNIT SUPPLEMENTAL INFORMATION
(Regulated Emissions Units Only)

Supplemental Requirements

1. Process Flow Diagram [X] Attached, Document ID: Figure 2-4 [ ] Not Applicable [ ] Waiver Requested
2. Fuel Analysis or Specification [X] Attached, Document ID: PSD Report [ ] Not Applicable [ ] Waiver Requested
3. Detailed Description of Control Equipment [X] Attached, Document ID:PSD Report [ ] Not Applicable [ ] Waiver Requested
4. Description of Stack Sampling Facilities [ ] Attached, Document ID:_______ [X] Not Applicable [ ] Waiver Requested
5. Compliance Test Report [ ] Attached, Document ID:_______ [ ] Previously submitted, Date:_____________ [X] Not Applicable
6. Procedures for Startup and Shutdown [X] Attached, Document ID: PSD Report [ ] Not Applicable [ ] Waiver Requested
7. Operation and Maintenance Plan [ ] Attached, Document ID:_______ [X] Not Applicable [ ] Waiver Requested
8. Supplemental Information for Construction Permit Application [X] Attached, Document ID:PSD Report [ ] Not Applicable
9. Other Information Required by Rule or Statute [X] Attached, Document ID:PSD Report [ ] Not Applicable
10. Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

11. Alternative Methods of Operation
    [ ] Attached, Document ID:________ [X] Not Applicable

12. Alternative Modes of Operation (Emissions Trading)
    [ ] Attached, Document ID:________ [X] Not Applicable

13. Identification of Additional Applicable Requirements
    [ ] Attached, Document ID:________ [X] Not Applicable

14. Compliance Assurance Monitoring Plan
    [ ] Attached, Document ID:________ [X] Not Applicable

15. Acid Rain Part Application (Hard-copy Required)

    [X] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a))
    Attached, Document ID: To be provided

    [ ] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.)
    Attached, Document ID:________

    [ ] New Unit Exemption (Form No. 62-210.900(1)(a)2.)
    Attached, Document ID:________

    [ ] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)
    Attached, Document ID:________

    [ ] Phase II NO_X Compliance Plan (Form No. 62-210.900(1)(a)4.)
    Attached, Document ID:________

    [ ] Phase NO_X Averaging Plan (Form No. 62-210.900(1)(a)5.)
    Attached, Document ID:________

    [ ] Not Applicable

Appendix B
Dispersion Modeling Information

INDEX of FILES on CD ROM

The CD-ROM included with this application contains all of the input and output files used or generated in the analysis described herein. The files are organized in the following Directories.
Duke Energy Fort Pierce, LLC Modeling 8/2000

- **Max-ROI**
  - **Fuel** (Natural Gas, Oil)
    - **Load%** (100%, 75%, 60%)
      - **Season** (Average Annual, Summer, Winter)

A description of the files contained in the above Subdirectories is provided below:

Max-ROI

Analysis of maximum impact and Radius of Impact (ROI) for proposed Facility's General Electric (Model GE 7EA) simple cycle combustion turbines.

Natural Gas, Maximum Load
Gas100mm.DTA Input Data File
Gas100mm.LST Output Data File
Gas100mm.GRF Plot File
Gas100mm.SO, Gas100mm.SUM, Gas100mm.TAB BPIP processing files and results

Natural Gas, 75% Load
Gas75mm.DTA Input Data File
Gas75mm.LST Output Data File
Gas75mm.GRF Plot File
Gas75mm.SO, Gas75mm.SUM, Gas75mm.TAB BPIP processing files and results

Natural Gas, 60% Load
Gas60mm.DTA Input Data File
Gas60mm.LST Output Data File
Gas60mm.GRF Plot File
Gas60mm.SO, Gas60mm.SUM, Gas60mm.TAB BPIP processing files and results

Oil, Maximum Load
Oil100mm.DTA Input Data File
Oil100mm.LST Output Data File
Oil100mm.GRF Plot File
Oil100mm.SO, Oil100.SUM, Oil100.TAB BPIP processing files and results

Oil, 75% Load
Oil100mm.DTA Input Data File
Oil10mm 0.LST Output Data File
Oil100mm.GRF Plot File

Oil100mm.SO, Oil100mm.SUM, Oil100mm.TAB BPIP processing files and results

Oil, 60% Load
Oil100 mm.DTA Input Data File
Oil100 mm.LST Output Data File
Oil100 mm.GRF Plot File
Oil100 mm.SO, Oil100mm.SUM, Oil100mm.TAB BPIP processing files and results

Where:
"mm" is year of met data modeled

Duke Energy - St. Lucie

100% Gas Load

Summer Scenario	1987	1988	1989	1990	1991
NO_X - Annual Avg.	0.0296	0.0306	0.0320	0.0338	0.0348
CO - 1-hr. Avg.	13.114	12.771	15.412	**17.595**	17.171
- 8-hr. Avg.	**4.158**	3.835	3.755	3.588	3.583
PM-10 - Annual Avg.	0.028	0.029	0.031	**0.033**	**0.033**
- 24-hr.	0.349	0.344	0.346	0.359	**0.379**
SO_2 - Annual Avg.	0.016	0.016	0.017	**0.018**	**0.018**
- 24-hr. Avg.	0.191	0.187	0.189	0.196	**0.207**
- 3-hr. Avg.	0.778	0.786	0.755	0.725	**1.139**

Average Scenario	1987	1988	1989	1990	1991
NO_X - Annual Avg.	0.0297	0.0304	0.0322	0.0340	0.0347
CO - 1-hr. Avg.	13.591	13.235	15.987	**18.256**	17.816
- 8-hr. Avg.	**4.235**	3.926	3.837	3.669	3.695
PM-10 - Annual Avg.	0.028	0.029	0.030	0.032	**0.033**
- 24-hr.	0.344	0.339	0.342	0.354	**0.369**
SO_2 - Annual Avg.	0.015	0.016	0.017	0.017	**0.018**
- 24-hr. Avg.	0.187	0.185	0.186	0.193	**0.201**
- 3-hr. Avg.	0.766	0.773	0.751	0.713	**1.136**

Winter Scenario	1987	1988	1989	1990	1991
NO_X - Annual Avg.	0.0316	0.0330	0.0345	0.0362	0.0369
CO - 1-hr. Avg.	15.008	14.610	17.685	16.890	**18.060**
- 8-hr. Avg.	4.426	4.180	4.063	3.876	**3.900**
PM-10 - Annual Avg.	0.026	0.027	0.028	0.030	**0.030**
- 24-hr.	0.330	0.324	0.326	0.336	**0.340**
SO_2 - Annual Avg.	0.017	0.017	0.018	**0.019**	**0.019**
- 24-hr. Avg.	0.210	0.206	0.207	0.214	**0.217**
- 3-hr. Avg.	0.852	0.855	0.864	0.789	**0.873**

Example Calculations

NO_x Annual Average, 1988 Winter Scenario

NO_X (ug/m^3) = (0.0244 ug/m^3)*(376 lb/hr/79.36508 lb/hr)*(2500 hrs/8760 hrs)

= 0.033 ug/m^3

PM-10 24-hr, 1988 Winter Scenario

PM-10 (ug/m^3) = (0.292 ug/m^3)*(88 lb/hr/79.36508 lb/hr)

= 0.324 ug/m^3

Duke Energy - St. Lucie **100% Gas Load**

Summer Scenario **Conversion Factors**

Averages	1987	1988	1989	1990	1991
Annual	0.0257	0.0266	0.0278	0.0294	0.0302
24-hr	0.315	0.310	0.312	0.324	0.342
8-hr	0.825	0.761	0.745	0.712	0.711
3-hr	1.287	1.299	1.248	1.199	1.884
1-hr	2.602	2.534	3.058	3.491	3.407

Average Scenario **Conversion Factors**

Averages	1987	1988	1989	1990	1991
Annual	0.0252	0.0258	0.0273	0.0288	0.0294
24-hr	0.310	0.306	0.308	0.319	0.333
8-hr	0.808	0.749	0.732	0.700	0.705
3-hr	1.267	1.278	1.242	1.179	1.879
1-hr	2.593	2.525	3.050	3.483	3.399

Winter Scenario **Conversion Factors**

Averages	1987	1988	1989	1990	1991
Annual	0.0234	0.0244	0.0255	0.0268	0.0273
24-hr	0.298	0.292	0.294	0.303	0.307
8-hr	0.757	0.715	0.695	0.663	0.667
3-hr	1.207	1.212	1.225	1.118	1.237
1-hr	2.567	2.499	3.025	2.889	3.089

Duke Energy - St. Lucie

75% Gas Load

Summer Scenario	1987	1988	1989	1990	1991
NO_X - Annual Avg.	0.0293	0.0295	0.0311	0.0334	0.0341
CO - 1-hr. Avg.	17.853	10.074	12.104	13.751	**40.150**
- 8-hr. Avg.	3.930	3.624	3.505	3.252	**5.753**
PM-10 - Annual Avg.	0.036	0.037	0.039	**0.042**	**0.042**
- 24-hr.	0.445	0.437	0.427	0.448	**0.538**
SO_2 - Annual Avg.	0.017	0.017	0.018	**0.019**	**0.019**
- 24-hr. Avg.	0.202	0.199	0.194	0.204	**0.244**
- 3-hr. Avg.	0.783	0.778	0.731	0.719	**1.761**

Average Scenario	1987	1988	1989	1990	1991
NO_X - Annual Avg.	0.0302	0.0305	0.0321	0.0321	0.0349
CO - 1-hr. Avg.	10.862	10.556	10.556	12.677	**41.219**
- 8-hr. Avg.	4.012	3.492	3.605	3.605	**5.907**
PM-10 - Annual Avg.	0.035	0.036	0.037	0.037	**0.041**
- 24-hr.	0.429	0.425	0.415	0.415	**0.526**
SO_2 - Annual Avg.	0.016	0.016	0.017	0.017	**0.019**
- 24-hr. Avg.	0.195	0.193	0.188	0.188	**0.239**
- 3-hr. Avg.	0.749	0.759	0.714	0.714	**1.718**

Winter Scenario	1987	1988	1989	1990	1991
NO_X - Annual Avg.	0.0319	0.0323	0.0343	0.0364	0.0374
CO - 1-hr. Avg.	13.958	13.712	16.349	18.623	**51.604**
- 8-hr. Avg.	4.980	4.392	4.529	4.178	**7.401**
PM-10 - Annual Avg.	0.033	0.034	0.036	0.038	**0.039**
- 24-hr.	0.406	0.409	0.397	0.407	**0.507**
SO_2 - Annual Avg.	0.018	0.018	0.019	0.021	**0.021**
- 24-hr. Avg.	0.221	0.223	0.217	0.222	**0.276**
- 3-hr. Avg.	0.867	0.878	0.826	0.810	**1.985**

Duke Energy - St. Lucie **75% Gas Load**

Summer Scenario **Conversion Factors**

Averages	1987	1988	1989	1990	1991
Annual	0.0328	0.0331	0.0349	0.0375	0.0382
24-hr	0.401	0.394	0.385	0.404	0.485
8-hr	1.026	0.946	0.915	0.849	1.502
3-hr	1.554	1.544	1.451	1.426	3.494
1-hr	4.661	2.630	3.160	3.590	10.482

Average Scenario **Conversion Factors**

Averages	1987	1988	1989	1990	1991
Annual	0.0318	0.0321	0.0338	0.0338	0.0368
24-hr	0.387	0.383	0.374	0.374	0.474
8-hr	0.995	0.866	0.894	0.894	1.465
3-hr	1.487	1.506	1.416	1.416	3.408
1-hr	2.694	2.618	2.618	3.144	10.223

Winter Scenario **Conversion Factors**

Averages	1987	1988	1989	1990	1991
Annual	0.0300	0.0303	0.0322	0.0342	0.0351
24-hr	0.366	0.369	0.358	0.367	0.457
8-hr	0.950	0.838	0.864	0.797	1.412
3-hr	1.434	1.451	1.366	1.339	3.282
1-hr	2.663	2.616	3.119	3.553	9.845

Duke Energy - St. Lucie

60% Gas Load

Summer Scenario	1987	1988	1989	1990	1991
NO_X - Annual Avg.	0.0294	0.0292	0.0313	0.0337	0.0343
CO - 1-hr. Avg.	30.015	26.478	18.784	26.893	**66.070**
- 8-hr. Avg.	6.642	5.805	6.150	5.396	**9.465**
PM-10 - Annual Avg.	0.040	0.040	0.043	0.046	**0.047**
- 24-hr.	0.498	0.473	0.467	0.503	**0.579**
SO_2 - Annual Avg.	0.015	0.015	0.016	**0.017**	**0.017**
- 24-hr. Avg.	0.181	0.172	0.170	0.183	**0.210**
- 3-hr. Avg.	0.690	0.671	0.629	0.619	**1.519**

Average Scenario	1987	1988	1989	1990	1991
NO_X - Annual Avg.	0.0293	0.0292	0.0312	0.0335	0.0341
CO - 1-hr. Avg.	17.973	9.660	11.587	15.956	**39.884**
- 8-hr. Avg.	3.970	3.538	3.734	3.248	**5.715**
PM-10 - Annual Avg.	0.039	0.039	0.041	**0.045**	**0.045**
- 24-hr.	0.478	0.459	0.452	0.481	**0.563**
SO_2 - Annual Avg.	0.018	0.018	0.019	0.020	**0.021**
- 24-hr. Avg.	0.217	0.209	0.206	0.219	**0.256**
- 3-hr. Avg.	0.832	0.815	0.766	0.753	**1.847**

Winter Scenario	1987	1988	1989	1990	1991
NO_X - Annual Avg.	0.0307	0.0309	0.0327	0.0352	0.0357
CO - 1-hr. Avg.	18.602	10.371	12.454	14.144	**41.683**
- 8-hr. Avg.	4.092	3.746	3.636	3.381	**5.975**
PM-10 - Annual Avg.	0.037	0.037	0.039	0.042	**0.043**
- 24-hr.	0.452	0.442	0.434	0.456	**0.544**
SO_2 - Annual Avg.	0.017	0.017	0.018	0.019	**0.020**
- 24-hr. Avg.	0.206	0.201	0.197	0.207	**0.247**
- 3-hr. Avg.	0.795	0.787	0.739	0.727	**1.781**

Duke Energy - St. Lucie **60% Gas Load**

Summer Scenario Conversion Factors

Averages	1987	1988	1989	1990	1991
Annual	0.0365	0.0363	0.0389	0.0419	0.0426
24-hr	0.449	0.427	0.421	0.454	0.522
8-hr	1.136	0.993	1.052	0.923	1.619
3-hr	1.711	1.664	1.560	1.536	3.767
1-hr	5.134	4.529	3.213	4.600	11.301

Average Scenario Conversion Factors

Averages	1987	1988	1989	1990	1991
Annual	0.0351	0.0350	0.0374	0.0402	0.0409
24-hr	0.431	0.414	0.408	0.434	0.508
8-hr	1.094	0.975	1.029	0.895	1.575
3-hr	1.651	1.618	1.519	1.495	3.664
1-hr	4.953	2.662	3.193	4.397	10.991

Winter Scenario Conversion Factors

Averages	1987	1988	1989	1990	1991
Annual	0.0334	0.0336	0.0355	0.0382	0.0388
24-hr	0.408	0.399	0.391	0.411	0.491
8-hr	1.041	0.953	0.925	0.860	1.520
3-hr	1.577	1.562	1.467	1.442	3.534
1-hr	4.732	2.638	3.168	3.598	10.603

Duke Energy - St. Lucie

100% Oil Load

Summer Scenario	1987	1988	1989	1990	1991
NO_X - Annual Avg.	0.0449	0.0459	0.0486	0.0512	**0.0526**
CO - 1-hr. Avg.	10.276	10.013	12.069	13.775	**14.266**
- 8-hr. Avg.	**3.342**	3.055	3.000	2.870	2.870
PM-10 - Annual Avg.	0.067	0.069	0.073	0.077	**0.079**
- 24-hr.	0.811	0.799	0.804	0.837	**0.897**
SO_2 - Annual Avg.	0.124	0.127	0.134	0.141	**0.145**
- 24-hr. Avg.	1.493	1.470	1.479	1.539	**1.651**
- 3-hr. Avg.	6.111	6.172	5.828	5.694	**8.773**

Average Scenario	1987	1988	1989	1990	1991
NO_X - Annual Avg.	0.0461	0.0472	0.0499	0.0527	**0.0540**
CO - 1-hr. Avg.	10.978	10.694	12.912	**14.746**	14.390
- 8-hr. Avg.	**3.421**	3.175	3.099	2.964	2.985
PM-10 - Annual Avg.	0.064	0.065	0.069	0.073	**0.074**
- 24-hr.	0.784	0.771	0.776	0.804	**0.842**
SO_2 - Annual Avg.	0.127	0.130	0.138	0.145	**0.149**
- 24-hr. Avg.	1.567	1.542	1.552	1.608	**1.683**
- 3-hr. Avg.	6.386	6.441	6.260	5.942	**9.470**

Winter Scenario	1987	1988	1989	1990	1991
NO_X - Annual Avg.	0.0484	0.0501	0.0528	0.0549	**0.0565**
CO - 1-hr. Avg.	12.133	11.816	14.308	13.659	**14.606**
- 8-hr. Avg.	**3.539**	3.359	3.259	3.108	3.127
PM-10 - Annual Avg.	0.061	0.063	0.066	0.069	**0.071**
- 24-hr.	0.776	0.757	0.763	0.784	**0.791**
SO_2 - Annual Avg.	0.135	0.140	0.147	0.153	**0.158**
- 24-hr. Avg.	1.731	1.690	1.701	1.748	**1.766**
- 3-hr. Avg.	6.986	7.010	7.144	6.466	**7.156**

Duke Energy - St. Lucie **100% Oil Load**

Summer Scenario **Conversion Factors**

Averages	1987	1988	1989	1990	1991
Annual	0.0267	0.0273	0.0289	0.0305	0.0313
24-hr	0.322	0.317	0.319	0.332	0.356
8-hr	0.850	0.777	0.763	0.730	0.730
3-hr	1.318	1.331	1.257	1.228	1.892
1-hr	2.614	2.547	3.070	3.504	3.629

Average Scenario **Conversion Factors**

Averages	1987	1988	1989	1990	1991
Annual	0.0252	0.0258	0.0273	0.0288	0.0295
24-hr	0.311	0.306	0.308	0.319	0.334
8-hr	0.808	0.750	0.732	0.700	0.705
3-hr	1.267	1.278	1.242	1.179	1.879
1-hr	2.593	2.526	3.050	3.483	3.399

Winter Scenario **Conversion Factors**

Averages	1987	1988	1989	1990	1991
Annual	0.0231	0.0239	0.0252	0.0262	0.0270
24-hr	0.296	0.289	0.291	0.299	0.302
8-hr	0.747	0.709	0.688	0.656	0.660
3-hr	1.195	1.199	1.222	1.106	1.224
1-hr	2.561	2.494	3.020	2.883	3.083

Duke Energy - St. Lucie

75% Oil Load

Summer Scenario	1987	1988	1989	1990	1991
NO_X - Annual Avg.	0.0446	0.0449	0.0475	0.0509	**0.0519**
CO - 1-hr. Avg.	14.468	8.212	9.865	11.209	**32.579**
- 8-hr. Avg.	3.184	2.753	2.844	2.640	**4.668**
PM-10 - Annual Avg.	0.079	0.079	0.084	0.090	**0.092**
- 24-hr.	0.963	0.946	0.927	0.970	**1.168**
SO_2 - Annual Avg.	0.125	0.126	0.133	0.142	**0.145**
- 24-hr. Avg.	1.524	1.498	1.467	1.536	**1.850**
- 3-hr. Avg.	5.910	5.883	5.527	5.432	**13.311**

Average Scenario	1987	1988	1989	1990	1991
NO_X - Annual Avg.	0.0464	0.0468	0.0493	0.0527	**0.0538**
CO - 1-hr. Avg.	8.945	8.705	10.442	11.879	**33.780**
- 8-hr. Avg.	3.280	2.864	2.954	2.734	**4.843**
PM-10 - Annual Avg.	0.076	0.077	0.081	0.087	**0.088**
- 24-hr.	0.927	0.922	0.898	0.931	**1.139**
SO_2 - Annual Avg.	0.130	0.131	0.138	0.148	**0.151**
- 24-hr. Avg.	1.583	1.575	1.533	1.591	**1.947**
- 3-hr. Avg.	6.104	6.183	5.815	5.707	**13.990**

Winter Scenario	1987	1988	1989	1990	1991
NO_X - Annual Avg.	0.0489	0.0494	0.0523	0.0556	**0.0571**
CO - 1-hr. Avg.	9.638	9.493	11.296	12.871	**13.459**
- 8-hr. Avg.	**3.404**	3.016	3.110	2.863	2.881
PM-10 - Annual Avg.	0.075	0.076	0.080	0.085	**0.087**
- 24-hr.	0.907	0.920	0.892	0.910	**1.013**
SO_2 - Annual Avg.	0.138	0.139	0.147	0.157	**0.161**
- 24-hr. Avg.	1.669	1.692	1.641	1.674	**1.864**
- 3-hr. Avg.	6.584	6.663	6.274	6.148	**8.889**

Duke Energy - St. Lucie **75% Oil Load**

Summer Scenario **Conversion Factors**

Averages	**1987**	**1988**	**1989**	**1990**	**1991**
Annual	0.0326	0.0328	0.0347	0.0372	0.0379
24-hr	0.398	0.391	0.383	0.401	0.483
8-hr	1.019	0.881	0.910	0.845	1.494
3-hr	1.543	1.536	1.443	1.418	3.475
1-hr	4.630	2.628	3.157	3.587	10.426

Average Scenario **Conversion Factors**

Averages	**1987**	**1988**	**1989**	**1990**	**1991**
Annual	0.0315	0.0318	0.0335	0.0358	0.0365
24-hr	0.383	0.381	0.371	0.385	0.471
8-hr	0.986	0.861	0.888	0.822	1.456
3-hr	1.477	1.496	1.407	1.381	3.385
1-hr	2.689	2.617	3.139	3.571	10.155

Winter Scenario **Conversion Factors**

Averages	**1987**	**1988**	**1989**	**1990**	**1991**
Annual	0.0297	0.0300	0.0318	0.0338	0.0347
24-hr	0.360	0.365	0.354	0.361	0.402
8-hr	0.938	0.831	0.857	0.789	0.794
3-hr	1.420	1.437	1.353	1.326	1.917
1-hr	2.656	2.616	3.113	3.547	3.709

Duke Energy - St. Lucie

60% Oil Load

Summer Scenario	1987	1988	1989	1990	1991
NO_X - Annual Avg.	0.0433	0.0432	0.0462	0.0498	**0.0504**
CO - 1-hr. Avg.	14.397	7.567	9.060	12.975	**31.738**
- 8-hr. Avg.	3.184	2.794	2.958	2.591	**4.547**
PM-10 - Annual Avg.	0.084	0.084	0.089	0.096	**0.098**
- 24-hr.	1.034	0.983	0.971	1.043	**1.206**
SO_2 - Annual Avg.	0.124	0.124	0.132	0.143	**0.144**
- 24-hr. Avg.	1.529	1.453	1.436	1.542	**1.782**
- 3-hr. Avg.	5.826	5.675	5.322	5.250	**12.845**

Average Scenario	1987	1988	1989	1990	1991
NO_X - Annual Avg.	0.0448	0.0448	0.0478	0.0513	**0.0522**
CO - 1-hr. Avg.	14.359	7.767	9.322	10.573	**31.738**
- 8-hr. Avg.	3.169	2.838	2.993	2.599	**4.575**
PM-10 - Annual Avg.	0.084	0.084	0.090	0.096	**0.098**
- 24-hr.	1.033	0.994	0.980	1.040	**1.222**
SO_2 - Annual Avg.	0.126	0.126	0.135	0.144	**0.147**
- 24-hr. Avg.	1.549	1.491	1.470	1.560	**1.833**
- 3-hr. Avg.	5.940	5.835	5.476	5.389	**13.209**

Winter Scenario	1987	1988	1989	1990	1991
NO_X - Annual Avg.	0.0478	0.0483	0.0509	0.0548	**0.0557**
CO - 1-hr. Avg.	15.112	8.493	10.203	11.590	**33.933**
- 8-hr. Avg.	3.326	3.058	2.961	2.751	**4.864**
PM-10 - Annual Avg.	0.080	0.081	0.085	0.091	**0.093**
- 24-hr.	0.977	0.956	0.936	0.982	**1.178**
SO_2 - Annual Avg.	0.133	0.134	0.142	0.152	**0.155**
- 24-hr. Avg.	1.629	1.593	1.560	1.637	**1.964**
- 3-hr. Avg.	6.298	6.250	5.871	5.770	**14.140**

Duke Energy - St. Lucie **60% Oil Load**

Summer Scenario **Conversion Factors**

Averages	1987	1988	1989	1990	1991
Annual	0.0362	0.0361	0.0386	0.0416	0.0421
24-hr	0.446	0.424	0.419	0.450	0.520
8-hr	1.128	0.990	1.048	0.918	1.611
3-hr	1.700	1.656	1.553	1.532	3.748
1-hr	5.101	2.681	3.210	4.597	11.245

Average Scenario **Conversion Factors**

Averages	1987	1988	1989	1990	1991
Annual	0.0348	0.0348	0.0371	0.0398	0.0405
24-hr	0.427	0.411	0.405	0.430	0.505
8-hr	1.084	0.971	1.024	0.889	1.565
3-hr	1.637	1.608	1.509	1.485	3.640
1-hr	4.912	2.657	3.189	3.617	10.921

Winter Scenario **Conversion Factors**

Averages	1987	1988	1989	1990	1991
Annual	0.033	0.0333	0.0351	0.0378	0.0384
24-hr	0.404	0.395	0.387	0.406	0.487
8-hr	1.031	0.948	0.918	0.853	1.508
3-hr	1.562	1.550	1.456	1.431	3.507
1-hr	4.685	2.633	3.163	3.593	10.52