<u>Check Sheet</u>

Company Name: FPC Hines Power Block 2

Permit Number:

PSD Number: PSD-FL-260

Permit Engineer: Halpin

Site Number: PA 92-33a

Application:

- [x] Initial Application
  - [ ] Incompleteness Letters
  - [ ] Responses
  - [ ] Waiver of Department Action
  - [ ] Department Response
  - [ ] Other

Cross References:

- [ ]
- [ ]
- [ ]

Intent:

- [ ] Intent to Issue
- [ ] Notice of Intent to Issue
- [ ] Technical Evaluation
- [ ] BACT Determination
- [ ] Unsigned Permit
- Correspondence with:
  - [x] EPA
  - [x] Park Services
  - [ ] Other
- [ ] Proof of Publication
  - [ ] Petitions - (Related to extensions, hearings, etc.)
  - [ ] Waiver of Department Action
  - [ ] Other

☑ Final Order

Withdrew Application

Final Determination:

- [ ] Final Determination
- [ ] Signed Permit
- [ ] BACT Determination
  - [ ] Other

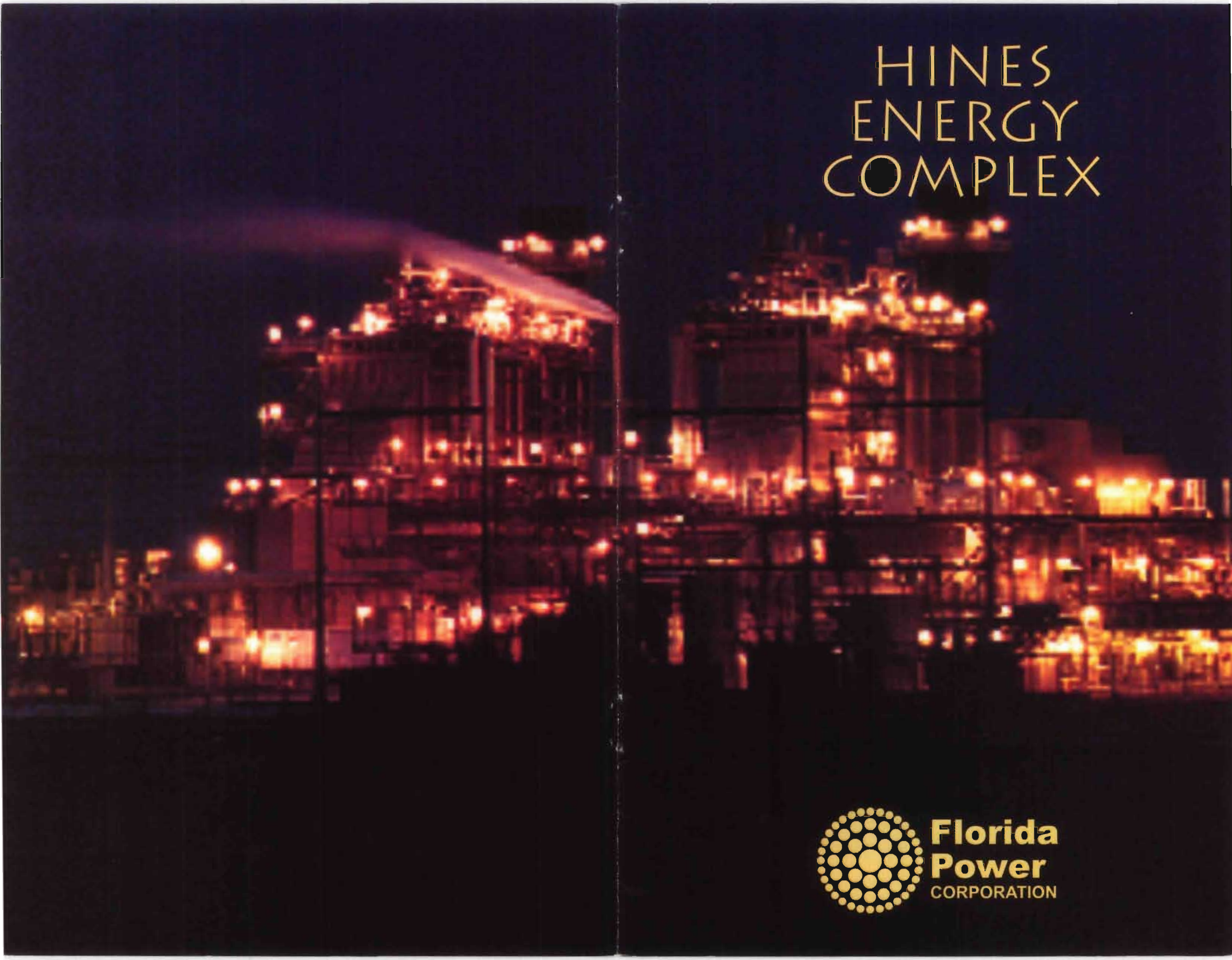
Post Permit Correspondence:

- [ ] Extensions/Amendments/Modifications
- [ ] Other

Florida Power
CORPORATION

① ~~Mike Halpin - Info then~~
~~Send to file. Please help~~
~~Russ if he needs help.~~
② Kim - No action - just
file in most recent
FPC Hines PSD Permit File.
Please consolidate FPC Hines
files if you haven't done so.

Thank you AAL


HINES
ENERGY
COMPLEX
Florida
Power
CORPORATION

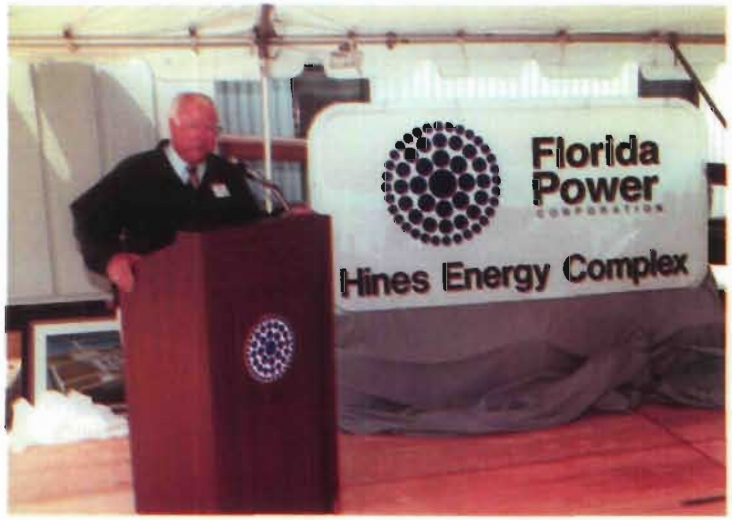
DEDICATION

The Hines Energy Complex is named after retired Florida Progress President and Chairman Andrew H. (Andy) Hines, Jr.

Hines was named president of Florida Power in 1972 and chief executive officer in 1973. He was president of the Southeastern Electric Exchange and chairman of the North American Electric Reliability Council.

In 1982, Hines assumed the presidency and chairmanship of the newly created Florida Progress Corporation. Under his leadership, Florida Progress was selected as the Florida company of the year. Hines retired in 1990 after a 38-year career with Florida Power and Florida Progress.

Hines' civic affiliations and honors include the University of Florida, University of South Florida, Rollins College where he is past Chairman of the Board, the YMCA and the Boy Scouts where he received a Silver Beaver Award (the highest award given by the Boy Scouts). He has received the Four Chaplains Award from the Civitan Club of St. Petersburg for "outstanding service to God and the community." Hines also was honored by the Tampa Bay Research Institute with a Humanitarian Award.



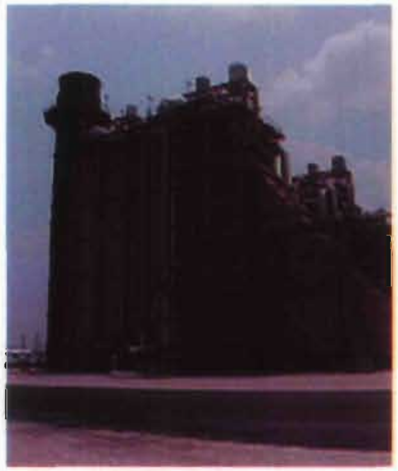
"It's a genuine honor to have this plant carry my name. I am most grateful to those responsible for this decision. I accept it as a representative of Florida Power men and women, past, present and future who have provided and will provide the flame of life to millions of people," said Andy Hines.

FUTURE

1000MW Artist's Rendition

WHAT THE FUTURE HOLDS

- The Hines Energy Complex has a site build-out capacity of 3,000 megawatts. It can accommodate five additional two on one combined-cycle units similar to power block one.
- The Hines Energy Complex has been designed with the capability for future conversion to coal gasification fuel. Coal gasification is a clean coal technology that has been available for many years but has been applied to electric power generation only recently. Coal gasification units, called gasifiers, produce a synthetic gas, derived from coal, that can be burned like natural gas in a combined-cycle power plant.
- Future decisions on technology will be continually reassessed during Florida Power Corporation's regular ongoing planning process, which involves a careful evaluation of options based on the most current information available at the time.



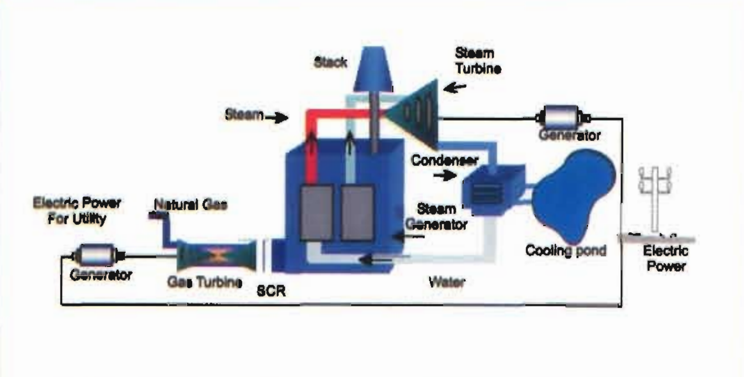
PLANT FACTS

Location:		Polk County, Florida, seven miles south of the City of Bartow.
Commercial Operation:		April 26, 1999
Generating Capacity:		470 MW
Annual Energy Production:		3,200,000 MWH
Annual Fuel Use*:		632 million lbs of natural gas
Cost to Build:		$275 million
Size:	Total Land Area	8,200 acres
	Area Used by Plant	210 acres
	Area of Cooling Pond	722 acres initially, 2,500 acres at ultimate site buildout

*This figure is based on average annual usage rates and may fluctuate from year to year.

ELECTRICITY

How Electricity is Made in "Combined-Cycle" Plants



A combined-cycle plant generates electricity from the direct burning of fuel in a combustion turbine. The waste heat from the combustion turbine is then used to produce steam in the heat recovery steam generator powering a steam turbine and producing additional electricity.

The first power block constructed at our Hines Energy Complex consists of two Westinghouse 501F combustion turbine generator sets, two Foster Wheeler heat recovery steam generators, and a single Westinghouse steam turbine generator set. This state-of-the-art ultra-low air emissions facility burns natural gas as its primary fuel with light oil available as backup fuel. Condenser cooling is provided by fresh water cooling ponds. The Hines combined-cycle power plant is the most efficient in Florida. It has a nominal capacity of 470 megawatts. The site will accommodate six power blocks of this size for a buildout capacity of 3,000 megawatts.

ENVIRONMENT

Florida Power Corporation's selection of combined-cycle power technology and fuel is heavily influenced by environmental concerns.

The Hines Energy Complex in Polk County was selected with the help of a group of citizens called the Environmental Advisory Group (EAG) during 1989 and 1990. Using the input of a citizens' committee to select potential plant sites was unique at that time. The EAG was made up of eight environmentalists, educators and community leaders throughout the state. The group had a vital role in Florida Power Corporation's selection of the current Hines Energy Complex site.

The site was developed on an 8,200-acre tract south of the city of Bartow. The property had been mined extensively for phosphate. The site's initial preparation involved moving over 10 million cubic yards of soil and draining 4 billion gallons of water. Construction of the energy complex will recycle the land for a beneficial use and promote habitat restoration.

The Hines Energy Complex is visited by several species of wildlife; including alligators, bobcats, turtles and over 50 species of birds. The Hines site also contains a wildlife corridor, which creates a continuous connection between the Peace River and the Alafia River.

Florida Power Corporation has arranged for the City of Bartow to provide treated effluent for cooling pond make-up. The complex's cooling pond initially covers 722 acres with an eventual expansion to 2,500 acres.

The Hines Energy Complex is designed and permitted to be a zero discharge site. This means that there will be no discharges to surface waters either from the power plant facilities or from storm water runoff. Based on this design, storm water runoff from the site can be used as cooling pond makeup, minimizing groundwater withdrawals.

Patty - FPC submitted an application via PPS over 1 year ago. They withdrew it + will resubmit. When they resubmit, we will probably keep PSD # and put in ARMS tracking. This goes in file we already set up. al

Florida Power CORPORATION

6/9/00
MTG. @ SITE CERTIF.

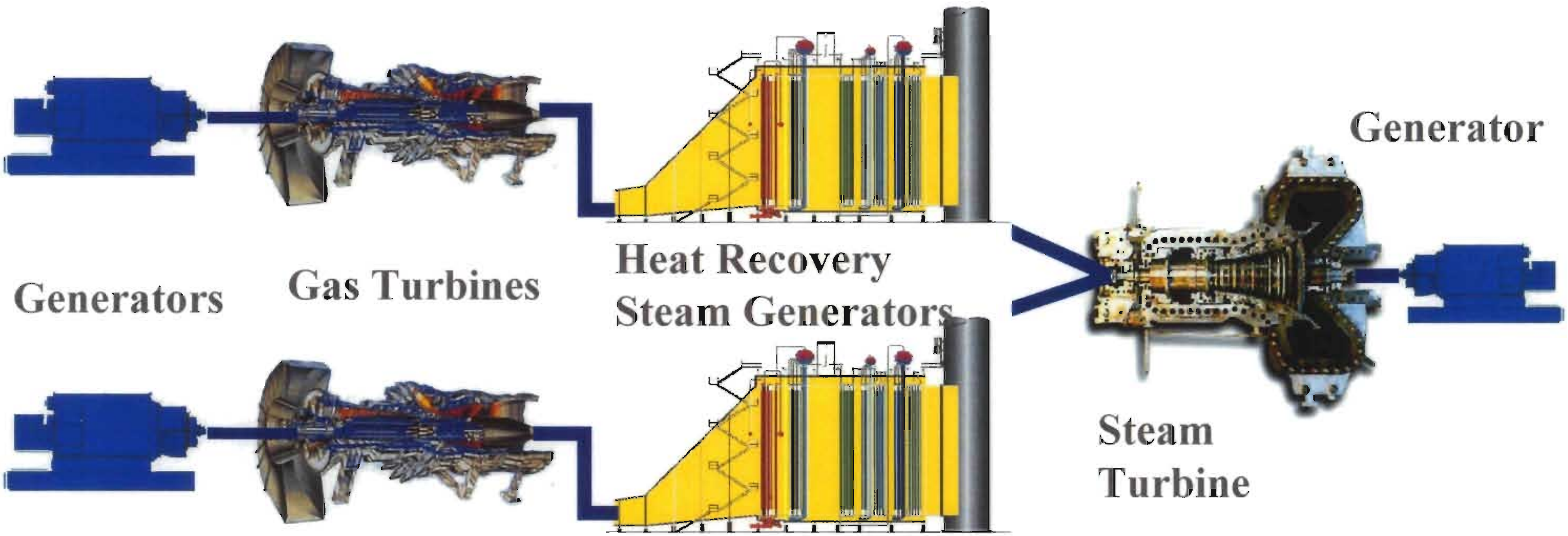
Hines Energy Complex

Site certified for 3000 MW - January 1994

- **Power Block 1 - in service - January 1999**
- **Power Block 2 - in service - Fall 2003**
  - Supplemental Certification Application (SCA) filing - Mid-2000
  - Agency Reports - Winter 2000
  - Hearing - Spring 2001
  - Certification - Summer 2001
  - Commencement of Construction - Winter 2001
  - Natural gas-fired combined cycle (dual fuel) — 0.05% S oil
  - Nominal output - 530 MW — 1000 HRS/CT
- **Fuel**
  - Clean burning natural gas / distillate oil (backup supply)
- **Transmission**
  - Existing transmission in-place
- **Water**
  - Innovative use of stormwater management for water supply
  - New water supply resource (Aquifer Recharge and Recovery Project)
- **Air**
  - State of the art control technology (BACT) 2x 501 F
- **Land Use**
  - Consistent with Polk County Land Use / Zoning Plans

3.5 ppm GAS NO_x (DLN w/ SCR)
15 ppm OIL (WI w/ SCR)
NO OXID. CATALYST
NO DUCT FIRING
INLET FOGGING

AIR - GOLDER
SITE VISIT AFT. APPLIC.



Two on One Combined Cycle

Florida Power
CORPORATION

HINES ENERGY COMPLEX

N
W E
S

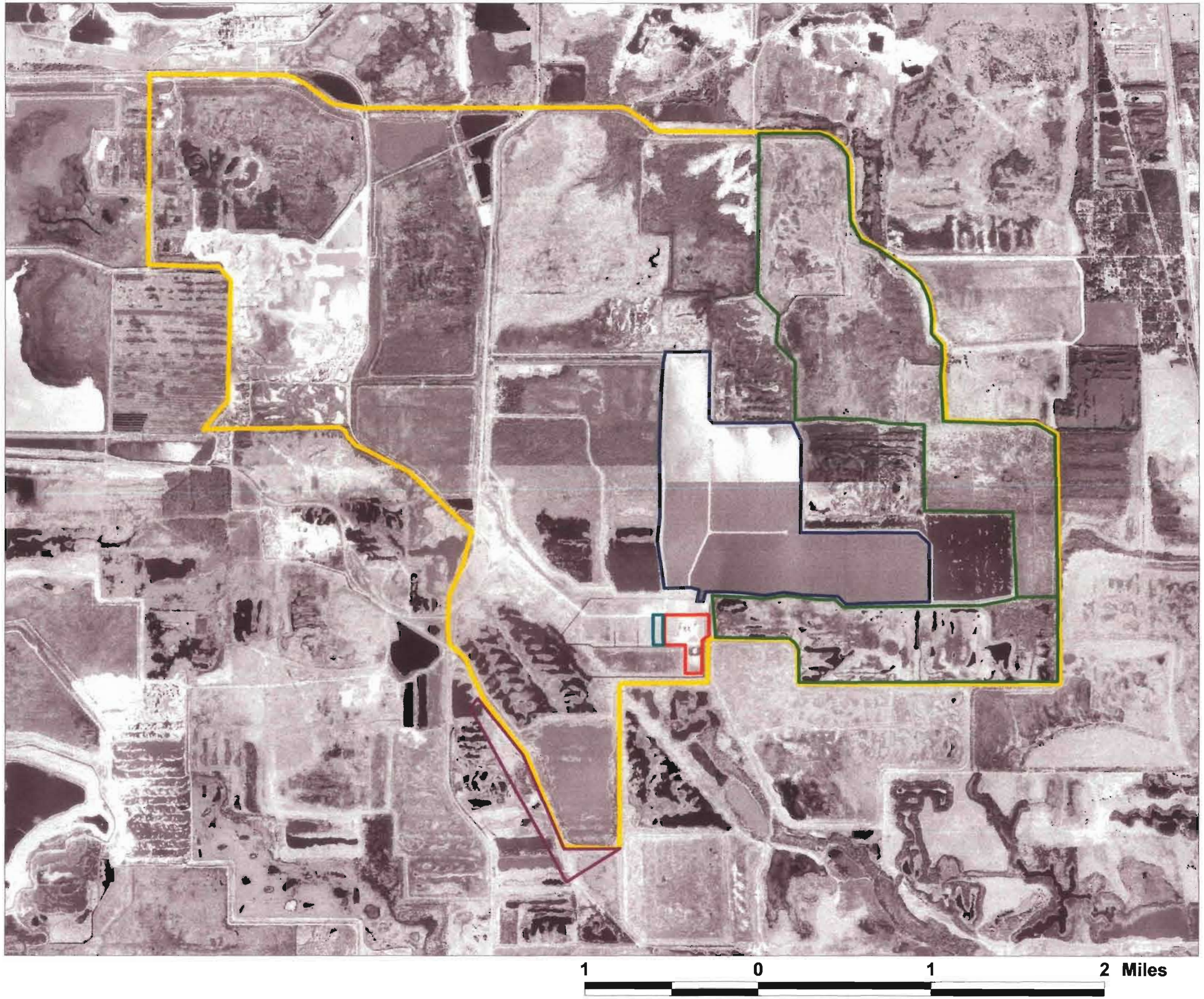
Cooling Pond

Unit 1

Unit 2 (Self Build Option)

Wildlife Corridor

Conservation Easement



Hines Energy Complex

Florida Power
CORPORATION

RECEIVED
MAY 22 2000
BUREAU OF AIR REGULATION

May 15, 2000

Mr. Scott Sheplak, P.E.
Bureau of Air Regulation
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Dear Mr. Sheplak:

Re: Revised Heat Input Curves - FPC Hines Facility

Enclosed are three originals of a construction permit application for the revision of the heat input curves for Units 1A and 1B at Florida Power Corporation's (FPC) Hines Energy Complex. Recall that Siemens/Westinghouse made an adjustment to improve the performance of the units, and this resulted in a minor change to the heat input curves for both natural gas and oil.

As the revised heat input curves show, the overall maximum heat input at 30 degrees F. for oil firing will not change from the curve incorporated into the permit on May 27, 1999. At 59 degrees F., the maximum heat input while firing oil will increase from the former 1,999 mmBtu/hour to 2,020 mmBtu/hour, which is an increase of 1.1%. The overall maximum heat input while firing natural gas will increase from 1,950 mmBtu/hour to 1,980 mmBtu/hour at 30 degrees F., which is an increase of 1.5%. At 59 degrees F., the maximum heat input while firing natural gas will increase from the current 1,866 mmBtu/hour to 1,915 mmBtu/hour, which is an increase of 2.6%.

In a discussion regarding this permit amendment on May 15, Mr. Al Linero of DEP and Mike Kennedy of FPC determined that the operating history of the Hines units is less than two years in duration; therefore, allowable emissions may be used as past actual emissions. In addition, FPC is not proposing to change any permitted emission limits.

FPC requests that, to the extent possible, the DEP co-process this construction permit amendment and the corresponding change to the draft Title V permit. However, due to the coming summer season demand for electricity, FPC requests that DEP issue the construction permit amendment as soon as possible in order to enable FPC to utilize the available capacity at Hines.

ONE POWER PLAZA, 263 - 13th Avenue South, BB1A, St. Petersburg, FL 33701-5511 •
P.O. Box 14042, BB1A • St. Petersburg • Florida 33733-4042 • (727) 820-5151
A Florida Progress Company

Thank you for your consideration of this request. Please contact Mike Kennedy at (727) 826-4334 if you have any questions.

Sincerely,

W. Jeffrey Pardue, C.E.P.
Director

Cc: Mr. Al Linero, DEP

Department of
Environmental Protection

DIVISION OF AIR RESOURCES MANAGEMENT

APPLICATION FOR AIR PERMIT - LONG FORM

I. APPLICATION INFORMATION

Identification of Facility Addressed in This Application

1. Facility Owner/Company Name : Florida Power Corporation		
2. Site Name : Hines Energy Complex		
3. Facility Identification Number :	1050234	[ ] Unknown
4. Facility Location : Bartow Street Address or Other Locator : City : Bartow	 7700 County Road 555 County : Polk	 Zip Code : 33841
5. Relocatable Facility? [ ] Yes [X] No		6. Existing Permitted Facility? [X] Yes [ ] No

Owner/Authorized Representative or Responsible Official

1. Name and Title of Owner/Authorized Representative or Responsible Official :

Name : W. Jeffrey Pardue, C.E.P.
Title : Director, Environmental Services

2. Owner or Authorized Representative or Responsible Official Mailing Address :

Organization/Firm : Florida Power Corporation
Street Address : P.O. Box 14042, MAC BB1A
City : St. Petersburg
State : FL Zip Code : 33733

3. Owner/Authorized Representative or Responsible Official Telephone Numbers :

Telephone : (727)826-4301 Fax : (727)826-4216

4. Owner/Authorized Representative or Responsible Official Statement :

I, the undersigned, am the owner or authorized representative of the non-Title V source addressed in this Application for Air Permit or the responsible official, as defined in Rule 62-210.200, F.A.C., 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 units.*

[signature] 5/15/00

Signature Date

* Attach letter of authorization if not currently on file.

Scope of Application

Emissions Unit ID	Description of Emissions Unit	Permit Type
001	170 MW Westinghouse 501F Combustion Turbine Unit 1	AC
002	170 MW Westinghouse 501F Combustion Turbine Unit 2	AC

Purpose of Application and Category

ategory I : All Air Operation Permit Applications Subject to Processing Under Chapter 62-213, .A.C.

This Application for Air Permit is submitted to obtain :

[ ] Initial air operation permit under Chapter 62-213, F.A.C., for an existing facility which is classified as a Title V source.

[ ] Initial air operation permit under Chapter 62-213, F.A.C., 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 :

[ ] Air operation permit renewal under Chapter 62-213, F.A.C., for a Title V source.

Operation permit to be renewed :

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

Current construction permit number :

Operation permit to be revised :

[ ] Air operation permit revision or administrative correction for a Title V source to address one or more proposed new or modified emissions units and to be processed concurrently with the air construction permit application.

Operation permit to be revised/corrected :

[ ] Air operation permit revision for a Title V source for reasons other than construction or modification of an emissions unit.

Operation permit to be revised :

Reason for revision :

ategory II : All Air Operation Permit Applications Subject to Processing Under Rule 2-210.300(2)(b), F.A.C.

This Application for Air Permit is submitted to obtain :

[ ] Initial air operation permit under Rule 62-210.300(2)(b), F.A.C., for an existing facility seeking classification as a synthetic non-Title V source.

Current operation/construction permit number(s) :

[ ] Renewal air operation permit under Fule 62-210.300(2)(b), F.A.C., for a synthetic non-Title V source.

Operation permit to be renewed :

[ ] Air operation permit revision for a synthetic non-Title V source.

Operation permit to be revised :

Reason for revision :

Category III : All Air Construction Permit Applications for All Facilities and Emissions Units

This Application for Air Permit is submitted to obtain :

[X] Air construction permit to construct or modify one or more emissions units within a facility (including any facility classified as a Title V source).

Current operation permit number(s), if any :
1050223-002-AV

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

Current operation permit number(s) :

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

Application Processing Fee

Check one :

[X] Attached - Amount : $250.00 [ ] Not Applicable.

Construction/Modification Information

1. Description of Proposed Project or Alterations : Proposed revision to the heat input curves for Power Block 1, Units 1A and 1B. Maximum heat input at 30 deg. F for oil firing does not change. Maximum heat input at 30 deg. F for natural gas firing increases from 1,950 to 1,980 mmBtu/hour.
2. Projected or Actual Date of Commencement of Construction :
3. Projected Date of Completion of Construction :

Professional Engineer Certification

1. Professional Engineer Name : Jennifer A. Stenger Registration Number : 0052125
2. Professional Engineer Mailing Address : Organization/Firm : Florida Power Corporation Street Address : P.O. Box 14042, MAC BB1A City : St. Petersburg State : FL Zip Code : 33733
3. Professional Engineer Telephone Numbers : Telephone : (727)826-4132 Fax : (727)826-4216

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 pollutant 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 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.

Jennifer A. Steger

Signature

(seal)

5/15/00

Date

* Attach any exception to certification statement.

Application Contact

1. Name and Title of Application Contact : Name : J. Michael Kennedy, Q.E.P. Title : Manager, Air Programs
2. Application Contact Mailing Address : Organization/Firm : Florida Power Corporation Street Address : P.O. Box 14042, MAC BB1A City : St. Petersburg State : FL Zip Code : 33733
3. Application Contact Telephone Numbers : Telephone : (727)826-4334 Fax : (727)826-4216

Application Comment

This application is for the proposed revision of the heat input curves for Units 1A and 1B.

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

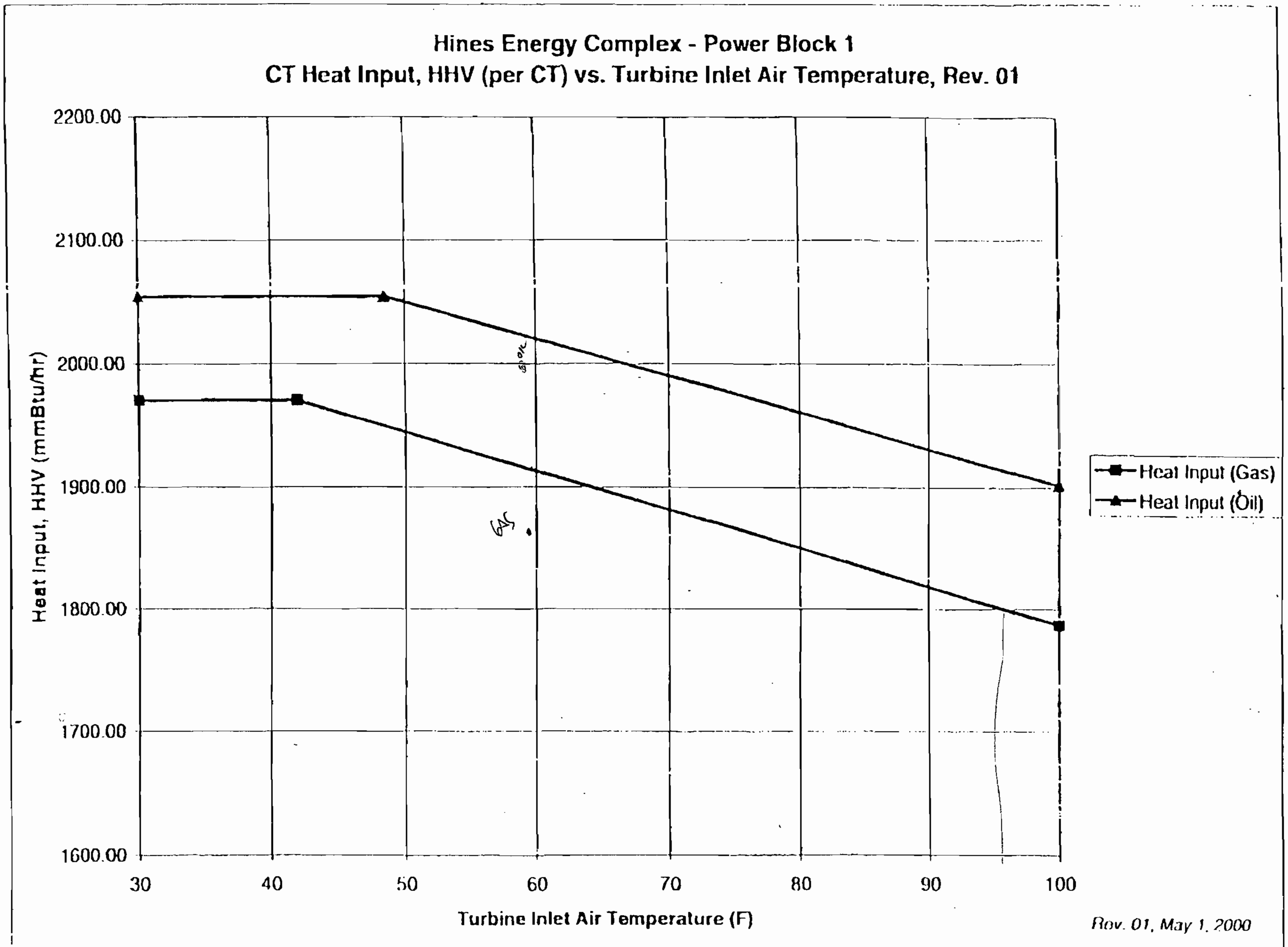
Facility, Location, and Type 10

1. Facility UTM Coordinates : Zone : 17 East (km) : 414.40 North (km) : 3073.90			
2. Facility Latitude/Longitude : Latitude (DD/MM/SS) : 27 47 19 Longitude (DD/MM/SS) : 81 52 10			
3. Governmental Facility Code : 0	4. Facility Status Code : A	5. Facility Major Group SIC Code : 49	6. Facility SIC(s) :
7. Facility Comment : Facility consists of two combined cycle combustion turbines (CT) with a heat recovery steam generator for a total generating capacity of a nominal 500 MW; a 99 mmBtu/hr auxiliary boiler, and a 1,300 KW diesel generator.			

Facility Contact

1. Name and Title of Facility Contact : Paul V. Crimi Asset Manager
2. Facility Contact Mailing Address : Organization/Firm : Florida Power Corporation Street Address : 3219 State Road 630 East City : Ft. Meade State : FL Zip Code : 33841
3. Facility Contact Telephone Numbers :

Telephone : (863)519-6101 Fax : (863)519-6110


Hines Energy Complex - Power Block 1
CT Heat Input, HHV (per CT) vs. Turbine Inlet Air Temperature, Rev. 01
Heat Input, HHV (mmBtu/hr)
2200.00
2100.00
2000.00
1900.00
1800.00
1700.00
1600.00
30
40
50
60
70
80
90
100
Turbine Inlet Air Temperature (F)
Heat Input (Gas)
Heat Input (Oil)
GAS
Rev. 01, May 1, 2000

United States Department of the Interior

FISH AND WILDLIFE SERVICE
1875 Century Boulevard
Atlanta, Georgia 30345

IN REPLY REFER TO:

February 16, 1999

RECEIVED
FEB 23 1999
BUREAU OF
AIR REGULATION

Re: PSD-FL-260

Mr. C. H. Fancy
Chief, Bureau of Air Regulation
Department of Environmental Regulation
Twin Towers Office Building
2600 Blair Stone Road, MS 48
Tallahassee, Florida 32399-2400

Dear Mr. Fancy:

Our Air Quality Branch has reviewed the Prevention of Significant Deterioration permit application for Florida Power Corporation's (FPC) proposal to construct and operate a combined cycle project at its Hines Energy Complex in Polk County, Florida. The facility is located 110 km southeast of Chassahowitzka Wilderness, a Class I air quality area, administered by the U.S. Fish and Wildlife Service. The comments from our Air Quality Branch are summarized in the enclosed technical review document and tables.

In summary, although FPC is proposing adequate control technologies for nitrogen oxides (NO_x), the level of control proposed by FPC does not fully utilize the potential of those technologies. We believe that FPC should be required to meet lower NO_x emission limits than those proposed.

In addition, FPC should evaluate potential impacts from this proposed project to visibility at the Class I area.

If you have any questions, please contact Ms. Ellen Porter of our Air Quality Branch in Denver at 303/969-2617.

Sincerely yours,

H Dale Hall

for Sam D. Hamilton
Regional Director

Enclosures

cc: B. Oven, PPS
K. Kosky, Golder Assoc.
J. Pardue, FPC

M. Halpin, BAR

Withdrew application

Technical Review of Prevention of Significant Deterioration Permit Application for a 500 MW Combined Cycle Project Florida Power Corporation's Hines Energy Complex Polk County, Florida PSD-FL-260

by

Air Quality Branch, Fish and Wildlife Service – Denver
February 10, 1999

Florida Power Corporation (FPC) is proposing to construct and operate two gas/oil-fired 165-megawatt (MW) Westinghouse 501F combined cycle turbines (CCT) with a 170 MW steam turbine generator at its Hines Energy Complex in Polk County, Florida. The facility is located 110 km southeast of Chassahowitzka Wilderness, a Class I air quality area administered by the U.S. Fish and Wildlife Service. The proposed project will result in significant increases in emissions of nitrogen oxides (NO_X), sulfur dioxide (SO_2) fine particulate matter (PM-10), particulate matter (PM), volatile organic compounds (VOC), sulfuric acid mist (SAM), and carbon monoxide (CO). Emissions (in tons per year – TPY) are summarized below.

POLLUTANT	EMISSIONS INCREASE (TPY)
NO_X	499
SO_2	93
PM-10	98
PM	98
VOC	143
SAM	9.5
CO	756

Best Available Control Technology (BACT) Analysis

FPC has proposed to meet NO_x limits of 6 parts per million by volume on a dry basis (ppmvd) corrected to 15% oxygen while burning natural gas. NO_x will be controlled by use of Selective Catalytic Reduction (SCR) which is capable of better than 80% NO_x removal efficiency. When burning oil, FPC proposes to limit NO_x to 42 ppm through the use of water injection.

While we agree with the control technologies proposed by FPC, we also believe that it can better utilize these technologies to achieve lower NO_x emissions. For example, SCR use on the overwhelming majority of newer units shown in the enclosed Table 1.b indicates that emissions in the 2.5-5 ppm range are readily achievable and feasible for this industry. FPC has rejected lower emission limits stating, "The only stationary sources required to meet this most stringent control technology emission limit are those new/modified sources being located in non-attainment areas, or sources which have other unique circumstances which require exceedingly stringent pollution control." Because only a few of the projects shown in Table 1.b. are in non-attainment areas, FPC should explain the unique circumstances that affect the other projects with lower NO_x limits. Furthermore, because FPC admits that lower NO_x limits are technically feasible, it should provide an economic evaluation of the cost of meeting a lower (down to 2.5 ppm NO_x limit) as required by the top-down BACT process.

FPC performed an economic analysis on the cost of meeting a 6 ppm NO_x limit. We have the following comments on their analysis:

The heat recovery steam generator modification cost should be explained.
The recurring catalyst cost is extraordinarily high and should be justified.
The costs of the PSM/RMP Plan and its update are extraordinarily high. Please explain what this plan includes and justify the associated high costs.
Contingency costs are much higher than the 3% recommended by the EPA Control Cost Manual.
Capital Recovery Factors and interest rates are higher than the 7% interest rate recommended by the EPA Control Cost Manual.
Energy costs for "Electrical," Fuel Escalation," and "Contingency" should be justified.

Although we have relatively little data with regard to NO_x limits when firing oil, it can be seen in Table 1.a. that limits in the 9-15 ppm range are common.

Emissions of other pollutants will be controlled primarily by good combustion techniques.

Conclusions and Recommendations

Although FPC is proposing adequate control technologies, the level of NO_x control proposed by FPC does not fully utilize the potential of those technologies. FPC has not documented or justified the extraordinarily high control costs contained in its application. We believe that NO_x can be controlled to a level of 2.5-5 ppm by the technology proposed and that the cost of such control would not exceed the $4,000 per ton typical of the industry. If FPC's costs really are exceptional, it must present more thorough evidence to support its claim.

Air Quality Analysis

The results of the air quality analysis indicate that the proposed project will not contribute significantly to consumption of the Class I increments for SO_2, nitrogen dioxide (NO_2), and PM-10.

Air Quality Related Values (AQRV) Analysis

FPC did not evaluate potential impacts to visibility at the Class I area. FPC should perform a regional haze analysis, following the recommendations of the Interagency Workgroup on Air Quality Modeling at: http://www.epa.gov/scram001/; "Model Support"; "6th Modeling Conference"; "IWAQM."

Contact: Ellen Porter, Air Quality Branch (303) 969-2617.

Table 1.a Gas Turbine Limits from RBLC

									NOx Emission Limits			
	Project Description							Permit	Dry Lox-NOx Comb.		SCR	
	Simple	Combined	Duct	Power Output				Issue	Gas	Oil	Gas	Oil
Facility Name	Cycle	Cycle	Burner	MW	mmBtu/hr	HP	Permit #	Date	(ppm)	(ppm)	(ppm)	(ppm)
Alabama Power Company		Y	Y	100	353	10566	AL-0115	Dec-97	15.0			
American Cogen Tech.								Sep-85			17.0	
Arrowhead Cogen								Dec-89			9.0	
Auburndale Power Part.				356	1214	36298	FL-0080	Dec-92	15.0	25.0		
Baf Energy								Jul-87			9.0	
Baltimore Gas & Electric				140	495	14792	MD-0019		15.0			
Bear Island Paper		Y	Y	139	474	14172	VA-0190	Oct-92			9.0	15.0
Berkshire, MA		Y		272							3.5	9.0
Bermuda Hundred								Mar-92			9.0	15.0
Blue Mtn. Pwr.			Y	153	541	16166	PA-0148	Jul-96	Y	Y	4.0	8.4
Brooklyn Navy Yard Cogen		Y		240	848	25358	NY-0044	Jun-95			3.5	10.0
Cimarron Chemical				0			CO-0020	Mar-91				
Cogen Technologies								Jun-87			9.6	
Doswell Ltd.								May-90			9.0	
Ecoelectrica		Y		461	1629	48709	PR-0004	Oct-96			7.0	9.0
Fleetwood Cogeneration			Y	105	360	10764	PA-0099	Apr-94			15.0	
Florida Power--Hines--Polk		Y		442	1510	45148	FL-0082	Feb-94	12.0	42.0		
Formosa Plastics		Y		132	450	13455	LA-0093	Mar-97	9.0			
Formosa Plastics		Y		132	450	13455	LA-0089	Mar-95	9.0			
Gainesville Regional Utilities	Y			74	262	7819	FL-0092	Apr-95	15.0			
Goal Line				113	386	11541	CA-0544	Nov-92			5.0	
Gordonsville Energy			Y	445	1520	45433	VA-0189	Sep-92			9.0	
Granite Road Limited				135	461	13781	CA-0441	May-92			3.5	
Grays Ferry		Y	Y	337	1150	34384	PA-0098	Nov-92	9.0			
Hermiston Generating		Y		497	1696	50709	OR-0011	Apr-94			4.5	
Kalamazoo Power				529	1806	53995	MI-0206	Dec-91	15.0			
Kamine/Besicorp				190	650	19434	NY-0049	Nov-92	9.0		9.0	
Kamine/Besicorp				191	653	19524	NY-0048	Nov-92	9.0		9.0	
Kingsburg Energy			Y	35	122	3645	CA-0347	Sep-89			6.0	
Kissimmee Utillty Authority				255	869	25982	FL-0078	Apr-93	15.0			
Lakewood Cogen								Apr-91			9.0	
Lakewood Cogeneration				56	190	5681	NJ-0013	Apr-91			9.0	
Las Vegas Cogen								Oct-90			10.0	
Linden Cogeneration		Y		165	583	17434	NJ-0011	Aug-91				
Lordsburg				100	353	10566	NM-0031	Jun-97	15.0			
Lsp-Cottage Grove				577	1970	58901	MN-0022	Mar-95			4.5	
Mid-Ga. Cogen				116	410	12257	GA-0063	Apr-96			9.0	20.0
Milagro, Williams Field Ser.				10983	37500	1121220	NM-0024					
Narragansett Electric			Y	398	1360	40663	RI-0010	Jun-96			9.0	
Newark Bay Cogen				171	585	17491	NJ-0009	Nov-90			8.3	
Newark Bay Cogen				181	617	18448	NJ-0017	Jun-93			8.3	16.0
Ocean State Power								Dec-88			9.0	
Ols Energy								Jan-86			9.0	
Orange Cogen				108	368	11012	FL-0068	Dec-93	15.0			
Panda-Kathleen		Y		75	265	7925	FL-0102	Jun-95	15.0			
Pasny/Holtsville		Y		336	1146	34264	NY-0047	Sep-92	9.0			
Pawtucket Power								Jan-89			9.0	
Pedricktown Cogen				293	1000	29899	NJ-0010	Feb-90			9.0	

Facility Name/Location	Project Description: Simple Cycle	Combined Cycle	Duct Burner	Power Output: MW	mmBtu/hr	HP	Permit #	Permit Issue Date	NOx Emission Limits < 25 ppm: Dry Lox-NOx Comb. Gas (ppm)	Dry Lox-NOx Comb. Oil (ppm)	SCR Gas (ppm)	SCR Oil (ppm)
Phoenix Power Part.				0				May-93	22.0			
Pilgrim Energy Center			Y	410	1400	41859	NY-0075	Apr-95			4.5	
Portland General Elec.				504	1720	51427	OR-0010	May-94			4.5	
Puerto Rico Electric Power	Y			248	876	26204	PR-0002	Jul-95			10.0	42.0
Richmond Power Enterprise								Dec-89			8.2	
Saguaro Power Company				35	122	3645	NV-0015	Jun-91			9.0	
Saranac Energy Company			Y	329	1123	33577	NY-0046	Jul-92			9.0	
Selkirk Cogen			Y	344	1173	35072	NY-0045	Jun-92			9.0	
Seminole Fertilizer								Mar-91			9.0	
Seminole Fertilizer Corp				26	92	2747	FL-0059	Mar-91			9.0	
Seminole Hardee Unit 3		Y		2 x 244	981	29331	FL-0104	Jan-96	15.0		12.0	
Sithe/Independence		Y		625	2133	63775		Nov-92			4.5	
So. Cal. Gas								Oct-91			8.0	
Southern CA Gas				0			CA-0418	Oct-91			8.0	
Southern CA Gas				54	184	5500	CA-0463	Oct-91			8.0	
Sumas Energy								Jun-91			8.0	
Sumas Energy								Dec-90			9.0	
Sumas Energy Inc				88	311	9298	WA-0027	Dec-92			6.0	
Sunlaw								Jun-85			9.0	
SW PSCo				100	353	10566	NM-0028	Nov-96	15.0			
SW PSCo				100	353	10566	NM-0029	Feb-97	?			
Talahassee		Y		260					12.0	42.0		
Tenaska WA Partners		Y	Y	1	2	55	WA-0275	May-92			7.0	
Tiger Bay				473	1615	48281	FL-0072	May-92	15.0			
Union Oil								Mar-86			2.5	
Unocal				0			CA-0613	Jul-89			9.0	
Western Power Sys.								Mar-86			9.0	
Willamette Ind.								Apr-85			15.0	

Table 1.b Permits Pending or Not Yet in RBLC

Facility Name/Location	Project Description: Simple Cycle	Combined Cycle	Duct Burner	Power Output: MW	mmBtu/hr	HP	Permit #	Permit Issue Date	NOx Emission Limits < 25 ppm: Dry Lox-NOx Comb. Gas (ppm)	Dry Lox-NOx Comb. Oil (ppm)	SCR Gas (ppm)	SCR Oil (ppm)
Alabama Pwr--Theodore		Y	Y	210			AL				3.5	
Androscoggin Energy		Y	Y	150	1857	55523	ME				6.0	42.0
ARCO Watson Project				45			CA	Oct-97			5.0	
Bridgeport Energy Project											6.0	
Brush	Y			25 x 2			CO		42 (1)			
Calpine--South Point		Y	Y	500			AZ		Y		4.5	
Casco Bay Energy		Y		520	1838	54943	ME				5.0	
Cogen Tech. Linden Venture		Y		581	1983	59275	NJ				3.5	
Col. Springs--Nixon	Y			33 x 2			CO		25.0			
Dighton, MA							MA				3.5	
Duke Energy--New Smyrna		Y		500			FL		12.0			
Enron (LAER)							CA				2.5	
Frontera Power		Y		330			TX		15.0			
Griffith Energy		Y	Y	650			AZ				4.5	
HDPP (LAER)							CA				3.0	
Hermiston Generating		Y					CA	Dec-95			4.5	
Kissimmee Utility--Cane Is. #1	Y			40			FL-182B		15.0			
Kissimmee Utility--Cane Is. #3		Y		250			FL					
Lakeland McIntosh CCT		Y		350			FL				7.5	15.0
Lakeland McIntosh SCT	Y			250	883	26415	FL		9.0	42.0		
LaPoloma Generating		Y		262 x 4			CA				3.0	
Mississippi Pwr--Daniels		Y		170			MI		Y		3.5	
Northwest Regional Power		Y		838	1530	45746	WA		9.0			
Oleander Power	Y			190 x 5			FL		9.0	42.0		
Orange Generation--Bartow		Y		41 x 2					15.0			
Rotterdam, N.Y.							NY				4.5	
Sacramento Power				115			CA	Dec-94			3.0	
Sutter				170					Y		3.5	
TVA--Gallatin	Y			85 x 4			TN		15.0			
TVA--Johnsonville	Y			85 x 4			TN		15.0			
TX-NM Pwr--Lordsburg		Y		80			NM		15.0	25.0		
Theodore Co-Gen		Y	Y								3.5	
Tiverton, RI							RI				3.5	

(1) does not use dry low-NOx combustor technology

Jeb Bush
Governor

Department of Environmental Protection

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

David B. Struhs
Secretary

February 1, 1999

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Gregg Worley, Chief
Preconstruction/HAP Section
Air, Radiation Technology Branch
US EPA Region IV
61 Forsyth Street
Atlanta, Georgia 30303

Re: FPC Hines Energy Complex - Power Block II
500 MW Combined Cycle Project
PA 92-33SA1, PSD-FL-260

Dear Mr. Worley:

Enclosed is a copy of a PSD application for a second nominal 500 MW combined cycle project planned by Florida Power Corporation at its Hines Energy Complex in Polk County, Florida. The project consists of two 165 MW Westinghouse 501F combustion turbine-electrical generators with unfired heat recovery steam generators powering a single 170 MW steam electrical generator. While the main fuel will be pipeline natural gas, maximum 0.05 percent sulfur fuel oil is proposed for a maximum of 1000 hours between the two new units.

Best Available Control Technology emission limits of NO_X are proposed throughout the entire operating range as the maximum pounds per hour achieved when controlling emissions at full load by selective catalytic reduction to 6 ppmvd @ 15 % O_2. BACT CO emission limits are proposed throughout the entire operating range as the lb/hr achieved when controlling emissions at full load to 25 ppm. Values for firing oil are based on 42 ppmvd @15% O_2 by wet injection for NO_X and 30 ppm for CO.

Attached is a copy of our preliminary sufficiency questions to FPC. We would appreciate your early review and comment. This project is subject to Florida's Power Plant Siting Act and will undergo an administrative hearing prior to review by the Governor and Cabinet. If you have any questions on this matter please call Mike Halpin at 850/921-9530.

Sincerely,

AAL 2/1

A. A. Linero, P.E., Administrator
New Source Review Section

AAL/aal

Enclosures

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Mr. Gregg Worley, Section Chief
Air, Radiation Technology Branch
Preconstruction/HAP Section
U.S. EPA - Region IV
61 Forsyth Street
Atlanta, GA 30303

*

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Z 333 612 508

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8. Addressee's Address *(Only if requested and fee is paid)*

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PS Form **3800**, April 1995

Memorandum | **Florida Department of Environmental Protection**

TO: Buck Oven, PPSO

THRU: Clair Fancy, Chief, BAR CHF

THRU: Al Linero, Administrator, NSR Section, BAR al Lin

FROM: Mike Halpin, Review Engineer MH

DATE: February 3, 1999

SUBJECT: FPC Hines Energy Complex - Power Block II
PA 92-33A and PSD-FL-260

Please include the following questions and comments in your Sufficiency package to Florida Power Corporation.

1. Please provide carbon monoxide (CO), nitrogen oxides (NO_X), volatile organic compounds (VOC), and particulate (PM/PM_{10}) emissions from the Westinghouse 501F as a function of percent unit output. It is preferred that these be provided as curves showing percent of full load on the abscissa and log of ppm on the ordinate. Indicate on the graph(s), the region of diffusion flame and the region of maximum lean premix combustion. These characteristics should be provided for both gas and fuel oil firing. Nitrogen oxides emissions should be indicated with and without selective catalytic reduction for both fuels. Additionally, provide timing data for start-up and shut-down so that hourly emissions can be better understood. Identify normal minimum load point as well as specific emission data at this load point.
2. Describe significant differences between the initially constructed units (Units 1 and 2) and the units described in this application which may affect air emissions.
3. Provide any emission test data acquired on Hines Units 1 and 2. Such data (initial compliance tests on the CT's) had been estimated to be available in January of 1999 as per the original conditions of certification XIII.B.4. If no data has of yet been acquired, indicate approximately when FDEP may obtain such data.
4. Refer to the comment on Page 4-8 of the application that "significant international pressure is now being exerted to reduce CO_2 emission levels in response to the suspected contributions of the gas to global warming. A CO oxidation catalyst could increase the CO_2 emissions from the facility by almost 360 pounds per hour (1660 TPY assuming 8760 hours per year of operation)." Comment on the fate of CO in the atmosphere if it is not catalytically converted to CO_2 within the units.

5. The original application for the Kissimmee Utilities Authority Cane Island Unit 3 included an estimate by Black & Veatch (design consultants for both the KUA and FPC projects) for annual CO emissions of roughly 3,400 - 3,800 tons per year (TPY) from a single Westinghouse 501F. Emissions from 720 hours per year were estimated at over 1000 tons. These were presumably over all possible load conditions. Please reconcile how the Power Block II Project will maintain emissions from each unit at approximately 376 TPY over the entire range of operation. Please provide reasonable assurance that annual CO emissions will be equal to or less than the value estimated. This can be by design information, control equipment, multi-load tests at similar facilities, or plans for continuous monitoring. For reference, note that Seminole Electric has similar CO limits at its Hardee Unit 3 to those requested by FPC for Power Block II. However, Seminole has advised that it will employ catalytic oxidation for its presumably identical Westinghouse 501F unit scheduled to be installed at approximately the same time as Power Block II.

6. For comparison purposes with the selective catalytic proposal, please provide a cost estimate from Goaline or ABB Environmental for $SCONO_X$ to reduce NO_X emissions from 35 ppm to 6 ppm of NO_X. Include in the estimate the possible impacts on CO emissions over the representative loads based on the reconciliation mentioned in question 5 above.

7. For comparison purposes, please inquire with Catalytica the availability and cost of XONON for NO_X control as well as a means to eliminate ammonia emissions.

8. Please submit the application information on an ELSA disk. This will facilitate the input of the application data in the Department's ARMS system.

We will provide Park Service and EPA comments as soon as they are available. Please advise FPC that they may contact me (Mike Halpin) at 850/921-9530 regarding the above questions.

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

February 1, 1999

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. John Bunyak, Chief
Policy, Planning & Permit Review Section
NPS-Air Quality Division
Post Office Box 25287
Denver, Colorado 80225

Re: FPC Hines Energy Complex - Power Block II
500 MW Combined Cycle Project
PA 92-33SA1, PSD-FL-260

Dear Mr. Bunyak:

Enclosed is a copy of a PSD application for a second nominal 500 MW combined cycle project planned by Florida Power Corporation at its Hines Energy Complex in Polk County, Florida. The project consists of two 165 MW Westinghouse 501F combustion turbine-electrical generators with unfired heat recovery steam generators powering a single 170 MW steam electrical generator. While the main fuel will be pipeline natural gas, maximum 0.05 percent sulfur fuel oil is proposed for a maximum of 1000 hours between the two new units.

Best Available Control Technology emission limits of NO_X are proposed throughout the entire operating range as the maximum pounds per hour achieved when controlling emissions at full load by selective catalytic reduction to 6 ppmvd @ 15 % O_2. BACT CO emission limits are proposed throughout the entire operating range as the lb/hr achieved when controlling emissions at full load to 25 ppm. Values for firing oil are based on 42 ppmvd @15% O_2 by wet injection for NO_X and 30 ppm for CO.

Attached is a copy of our preliminary sufficiency questions to FPC. We would appreciate your early review and comment. This project is subject to Florida's Power Plant Siting Act and will undergo an administrative hearing prior to review by the Governor and Cabinet. If you have any questions on this matter please call Mike Halpin at 850/921-9530.

Sincerely,

A A Lin 2/1

A. A. Linero, P.E., Administrator
New Source Review Section

AAL/aal

Enclosures

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PS Form **3800**, April 1995

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Policy, Planning & Permit R.
NPS-Air Quality
PO Box 25287
Denver, Co 80225

4a. Article Number
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Florida Power
CORPORATION

January 11, 1999

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Mr. Al Linero, P.E.
Administrator, New Source Review Section
Bureau of Air Regulation
Florida Department of Environmental Protection
2600 Blair Stone Rd.
Tallahassee, Florida 32399

Dear Mr. Linero:

Re: Modeling Files for Hines Power Block 2

The purpose of this letter is to transmit the air quality dispersion modeling files for Florida Power Corporation's (FPC) proposed Hines Power Block 2 PSD permit application. Due to the volume of information contained in these files, they were not included as part of the application document. Attachment 1 to this letter contains the SCREEN3 model output used to evaluate the most conservative unit load conditions by pollutant. The ISCST3 input and output files from the refined modeling analysis are contained on the three diskettes included with this letter. In order to identify the files, the following describes the file naming system:

Filename: hi2xxxyy.zii

hi2 - refers to Hines Power Block 2
xxx - pollutant designation (SO_2, NO_2, PM, CO)
yy - if necessary, denotes short-term (st) or long-term (lt) run
z - denotes input (I) or output (o) file
ii - denotes year of meteorological data (87 through 91)

Please feel free to review these files in conjunction with the PSD permit application review. Please contact me at (727) 826-4334 if you have any questions.

Sincerely,

J. Michael Kennedy

J. Michael Kennedy, Q.E.P.
Manager, Air Programs

BEFORE THE STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

In Re: Florida Power Corporation)
Hines Energy Complex)
(Polk County Site)) DEP File No. PA92-33D
Modification of Conditions) OGC Case No. 98-2296
of Certification)
Polk County, Florida)

RECEIVED
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FINAL ORDER MODIFYING
CONDITIONS OF CERTIFICATION

On January 27, 1994, the Governor and Cabinet, sitting as the Siting Board, issued a final order approving certification for Florida Power Corporation's Polk County site, now known as the Hines Energy Complex. That certification order approved the construction and operation of a 470 MW, natural gas-fired, combined cycle power plant and associated facilities located in Polk County, Florida.

On July 1, 1998, Florida Power Corporation (FPC) filed a request to amend their application to reflect installation of a Selective Catalytic Reduction system (SCR) to achieve the NOx emission levels specified in the Prevention of Significant Deterioration Permit (PSD) and the Conditions of Certification. Pursuant to Section 403.516(1)(b), Florida Statutes and Condition of Certification XI.B., FPC requested that the conditions be modified to allow conformance with the amended PSD permit for the facility (PSD-FL-195A).

On August 6, 1998, all parties to the original proceeding were furnished copies of the notice of intent to issue permit modification. The notice specified that a hearing would be held if a party to the original certification hearing objected within 45 days from receipt of the notice, or if any other person whose interests would be substantially affected objected in writing within 30 days after issuance of the public notice. Copies of FPC's proposed modifications were made available for public review on August 13, 1998. On October 16, 1998, a Proposed Modification of Power Plant Certification was published in the Florida Administrative Weekly. No written objection to the proposed modifications has been received by the Department. The PSD amendment was issued on September 29, 1998. Accordingly, in the absence of any timely objection,

IT IS ORDERED:

The proposed changes to the Florida Power Corporation's (FPC's) Hines Energy Complex as described in its July 1, 1998, request for modification are APPROVED. Pursuant to Section 403.516(1)(b), F.S., the conditions of certification for the Hines Energy Complex are **MODIFIED** as follows:

XIII. AIR

The construction and operation of the Hines Energy Complex ~~Polk County Site~~ (Project) shall be in accordance with all applicable provisions of Chapters 62 ~~17~~-210 to 297, F.A.C. and New Source Performance Standards (NSPS) Subparts GG, Dc, and Kb. The following emission limitations and conditions reflect BACT determinations for the Power Block 1- 485 ~~Phase IA-470~~ MW (two combined cycle combustion turbines and auxiliary equipment) of generating capacity for which the need has been determined. BACT determinations for the remaining phases will be made upon review of supplemental applications. In addition to the foregoing, the Project shall comply with the following conditions of certification as indicated.

A. General Requirements

1. The maximum heat input (HHV) to each combustion turbine (CT) at an ambient temperature of 59° F shall neither exceed 1,757 ~~1,510~~ MMBtu/hr while firing natural gas, nor 1,846 ~~1,730~~ MMBtu/hr while firing fuel oil. Heat input may vary depending on ambient conditions and the CT characteristics. Manufacturer's curves or equations for correction to other temperatures shall be provided to DEP for review 90 days after selection of the CT. Subject to approval by the Department for technical validity applying sound engineering principles, the manufacturer's curves shall be used to establish heat input rates over a range of temperatures for the purpose of compliance determination.

2. Each of the two CTs in Power Block 1 ~~Phase IA~~ may operate continuously, i.e., 8,760 hrs/year.

3. Only natural gas (NG) or low sulfur fuel oil shall be fired in each combustion turbine ~~and the auxiliary boiler~~. Only low sulfur fuel oil shall be fired in the diesel generator. The maximum sulfur content of the low sulfur fuel oil shall not exceed 0.05 percent, by weight. Only natural gas shall be fired in the auxiliary boiler.

4. The maximum heat input to the auxiliary boiler shall not exceed 99 MMBtu/hr ~~when firing NG or No. 2 fuel oil with 0.05 percent maximum sulfur content (by weight)~~. All fuel consumption shall be ~~must be continuously~~ measured and recorded for the auxiliary boiler.

5. No change.

6. No change.

7. No change.

8. If site construction does not commence on Power Block 1 ~~Phase IA~~ (485 ~~470~~ MW) within 18 months of issuance of PSD Permit No. PSD-FL-195A ~~this certification~~, then FPC may request an extension of the 18-month period, provided that such request is received by the Department's Bureau of Air Regulation at least 90 days prior to the expiration date. Such a request shall identify the progress made toward commencement of the construction of the site and the expected time required to start and complete construction of the initial phase. The Department may grant the extension upon a satisfactory showing that the extension is justified.

Units to be constructed or modified in later phases of the project will be reviewed under the supplementary review process of the Power Plant Siting Act. If site construction has not commenced within 18 months of issuance of this certification, then FPC shall obtain from DEP a review and, if necessary, a modification of the BACT determination and allowable emissions for the unit(s) on which construction has not commenced [40 CFR 52.21(r)(2)].

B. Emission Limits

1. The maximum allowable emissions from each of the two CTs, when firing natural gas or low sulfur fuel oil, in accordance with the BACT determination and subsequent data from Westinghouse, shall not exceed the following (at 59° F reference temperature for NOx emissions) (except during periods of start up, shutdown, and malfunction ~~and load change~~):

EMISSIONS LIMITATIONS

POLLUTANT	FUEL	BASIS(g)	LB/HR/CT	TPY(b)
NOx (a)	Gas	12 ~~2~~ ppmvd (h)	73(i)	639
	Oil	42 ~~2~~ ppmvd © (h)	305	153
VOC (d)	Gas	7 ppmvw	10.4	91
	Oil	10 ~~7~~ ppmvw	19.0 ~~11.2~~	5.6
CO	Gas	25 ppmvd	77	675
	Oil	30 ppmvd	93	47
PM/PM_{10}	Gas		15.6 ~~9~~	79
	Oil(e)		44.8 ~~17~~	21 ~~8.5~~
SO_2	Gas(f)		4.7 ~~0.99~~	44 ~~8.7~~
	Oil(f)		94	47
Visible Emissions	Gas	10 percent opacity		
	Oil	20 percent opacity		

a. ~~Emission limitations in LB/HR/CT of NOx are blocked 24-hour averages (midnight to midnight).~~ Pollutant emission rates may vary depending on ambient conditions (compressor inlet temperatures) and the CT characteristics. Manufacturer's curves for the NOx emission rate correction to other temperatures at different loads shall be provided to DEP for review 90 days after selection of the CT. Subject to approval by the Department for technical validity applying sound engineering principles, the manufacturer's curves shall be used to establish pollutant emission rates over a range of temperatures for the purpose of compliance determination. Emission limitations in LB/HR/CT of NOx are blocked 24-hour averages (midnight to midnight) and are calculated as follows:

NO_X emissions shall be determined continuously by a Continuous Emissions Monitoring System (CEMS). A CEMS operated and maintained in accordance with 40 CFR 75 shall be used. Compliance with the NO_X emissions standards in the above table shall be demonstrated with this CEMS system based on a 24-hour block average. Based on CEMS data at the end of each operating day, new 24-hour average emission rates, both actual and allowable (based on compressor inlet temperatures), are calculated from the arithmetic average of all valid hourly emission rates during the previous 24 operating hours. Valid hourly emission rates shall not include periods of startup (including fuel switching), shutdown, or malfunction as defined in Rule 62-210.200 where emissions exceed the NO_X standard. These excess emission periods shall be reported as required in Specific Condition E.2.f. A valid hourly emission rate shall be calculated for each hour in which two NO_X and carbon dioxide (or oxygen) concentrations are obtained at least 15 minutes apart. When monitoring data is not available, substitution for missing data shall be handled as required by Title IV (40 CFR 75) to calculate the 24-hour block average.

b. Annual emission limits (TPY) for natural gas are based on a total of two CTs operating at full load 8,760 hours per year (i.e., NO_x - 73 lbs/hr X 2 CTs X 8,760 hrs/yr X 1 ton/2,000 lbs = 639 TPY). Annual emission limits (TPY) for fuel oil are based on full load operation for a total of 1,000 hours per year for the two CTs (i.e., NO_x - 305 lbs/hr X 1,000 hrs/yr X 1 ton/2,000 lbs = 153 TPY).

c. Fuel oil NO_x emissions are based on full load operation ~~at ISO conditions~~ and 15 percent oxygen. For fuel oil firing, NO_x levels of 42 ppmvd @ 15 percent O_2 are based on a fuel bound nitrogen content of 0.015 percent or less. The emission limit for NO_x is adjusted as follows for higher fuel nitrogen contents up to a maximum of 0.030 percent by weight:

FUEL BOUND NITROGEN (% BY WEIGHT)	NO_X LEVELS (PPMVD @ 15% O_2)	NO_X EMISSIONS LB/HR/CT	NO_X EMISSIONS TPY
0.015 or less	42	305	153
0.020	44	320	160
0.025	46	334	167
0.030	48	349	175

using the formula STD = 0.0042 + F where:

STD = allowable NO_x emissions (percent by volume at 15 percent O_2 and on a dry basis).

F = NO_x emission allowance for fuel-bound nitrogen defined by the following table:

FUEL-BOUND NITROGEN (% BY WEIGHT)	F (NO_X % BY VOLUME)
$0 < N < 0.015$	0
$0.015 < N < 0.03$	0.04(N-0.015)

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

NO_x emissions limits are preliminary for the fuel oil specified in Specific Condition No. A.3. FPC shall maintain and submit fuel bound nitrogen content data for the low sulfur fuel oil prior to commercial operation. Adjustments of the NO_x standard (up and down) shall be calculated and recorded based upon a volume weighted average of the nitrogen content of each bulk fuel oil shipment and the nitrogen content of the existing fuel in the storage tank. The NO_x emission allowance (F) for fuel oil shall not be adjusted between fuel oil shipments. Records for these adjusted standards shall be kept on site for a minimum of 5 years.

d. Exclusive of background concentrations.

e. PM/PM_{10} emission limitations include ~~are exclusive of~~ sulfuric acid mist.

f. SO_2 emissions are based on a maximum of 1 grain of S/100cf of natural gas and 0.05 percent sulfur in the fuel oil.

g. No change.

h. ~~12 ppmvd a~~ At 15 percent O_2, not ISO corrected. ~~The ISO corrected value is 15 ppmvd at 15 percent O_2. Compliance will be determined through the initial and annual compliance tests required in Condition XIII.C.1.~~

i. Control of nitrogen oxides from each CT while firing natural gas shall be accomplished using dry low NOx burners (DLN) and SCR. Ammonia slip shall not exceed 10 ppm. If the Westinghouse Piloted Ring Combustor (PRC) or a more advanced DLN burner is developed which is able to comply with the emission limits (listed in the above table) and is installed by November 1, 2000, the SCR system may be removed and replaced with these new burners upon 30 days prior notice to DEP. This action would implement the original BACT for NOx and would not be subject to PSD review. This notice shall include information on the new burners which provides reasonable assurance and PE certification that these DLN burners can consistently meet the BACT emission limits. In this case the new dry low NOx burners shall be tested in accordance with the initial performance test as described in Section XIII.C.1 within 180 days of startup with the new burners.

2. No change.

~~3. FPC will install a dry low NO_x combustion turbine (CT). FPC shall make every practicable effort to achieve with that CT the lowest possible NO_x emission rate but must not exceed 73 lbs/hr (based on 12 ppmvd at 15 percent O_2 and 59° F) per CT (24-hour average, not including down time) on a continuous basis when firing natural gas.~~

~~4. After the initial compliance tests on the CTs (estimated to be in January, 1999), FPC shall operate a certified continuous emissions monitor for NO_x emissions, and collect 12 months of monitoring data. The monitor will at a minimum meet the requirements of 40 CFR 60 Appendix F quality assurance procedures. Within 17 months after the initial compliance test FPC shall prepare and submit for the Department's review an engineering report regarding the collection and the analysis of the data gathered from the monitor. In addition, this report shall include a conclusion regarding the lowest NO_x emission rate which can be consistently achieved with a reasonable operating margin taking into account long-term performance expectations and assuming good operating and maintenance practices. The report shall also include results of the testing requirements of Appendix F procedures and the actual CEM data for the period of the study in an acceptable format.~~

~~5. One month after submittal of the engineering report (estimated to be by June 2000), the Department will make a determination based on the engineering report submitted by FPC on the revised NO_x emission limits. If the data demonstrate that a NO_x emission rate of less than 73 lb/hr (based on 12 ppmvd at 15 percent O_2 and 59°F) is consistently achievable, the NO_x emission limits may be adjusted accordingly, but not lower than 55 lb/hr (based on 9 ppm at 15 percent O_2 and 59°F).~~

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

4. ~~7.~~ Operation of the auxiliary steam boiler shall be limited to a maximum of 1000 hours per year and only during periods of cold CT startup or quick startup out of a short-term shutdown mode, when no other source of steam is available, or during periodic testing. The following emission limitations shall apply:

a. No change.

b. No change.

c. No change.

5. ~~8.~~ Operation of the --- No change.

C. Performance Testing

1. An ~~I~~initial (I) ~~compliance~~ performance tests shall be performed on each CT for each ~~using both~~ fuels. Testing of emissions shall be conducted with the source operating at capacity (maximum heat input rate for the tested operating temperature). Capacity is defined as 90 - 100 percent of permitted ~~rated~~ capacity. If it is impracticable to test at capacity, then sources may be tested at less than capacity; in this case subsequent source operation is limited to 110 percent of the test load until a new test is conducted. Once the unit is so limited, then operation at higher capacities is allowed for no more than fifteen consecutive days for purposes of additional compliance testing to regain the rated capacity in the permit, with prior notification to the Department. Annual (A) compliance tests shall be performed on each CT with the fuel(s)

indicated below ~~used for more than 400 hours in the preceeding 12 month period~~. Tests shall be conducted using EPA reference methods in accordance with 40 CFR 60, Appendix A, as adopted by reference in Rule 62~~17~~-297, F.A.C.:

a. Reference Method 5~~B~~or 17 for PM (I, A~~,~~- only for oil and only if fuel oil is fired more than 400 hours for the CT in the previous federal fiscal year).

b. Reference Method 9 for VE (I, A- only for oil and only if fuel oil is fired more than 400 hours for the CT in the previous federal fiscal year).

c. Reference Method 10 for CO (I, A- for gas and annually for oil if fuel oil is fired more than 400 hours for the CT in the previous federal fiscal year).

d. Reference Method 20 for NOx (I ~~A~~ only, for compliance with 40 CFR 60.332 and 40 CFR 60.335).

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

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

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

g. ~~h.~~ ASTM D1072-80, D3031-81, D4084-82, or D3246-81 (or equivalent) for sulfur content of natural gas (I~~, and A if deemed necessary by DEP~~).

h. Ammonia (I) by EPA Conditional Test Method CTM-027 or a test method approved by DEP prior to the initial performance test.

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

2. The maximum sulfur content of the low sulfur fuel oil shall not exceed 0.05 percent by weight. Compliance shall be demonstrated in accordance with the requirements of 40 CFR 60.334 testing for sulfur content of the fuel oil in the storage tanks on each occasion that fuel is transferred to the storage tanks from any other source. Testing for fuel bound nitrogen content by ASTM D3431 or D4629 or other equivalent ASTM method, and for fuel oil ~~lower~~ higher heating value, shall also be conducted on the same schedule.

D. Monitoring Requirements

For each combined cycle unit, the permittee ~~FPC~~ shall install, operate, and maintain a continuous emission monitoring system (CEMS) (in accordance with 40 CFR 60, Appendix F or 40 CFR 75) or use other DEP approved alternate methods to monitor nitrogen oxides and, if necessary, a diluent gas (CO_2 or O_2). The Federal Acid Rain Program requirements of 40 CFR 75 shall apply when those requirements become effective for the CTs ~~within the state~~.

1. Each CEMS shall meet performance specifications of 40 CFR 60, Appendix B or 40 CFR 75.

2. CEMS data shall be recorded and reported in accordance with ~~Chapter 17-297, F.A.C.,~~ 40 CFR 60 Appendix A and Subpart GG and 40 CFR 75. The record shall include periods of start up, shutdown, and malfunction. ~~Continuous~~ compliance with condition XIII.B.1. for NO_x shall be determined by CEMS on a mass emission rate basis (LB/HR) using EPA Method 19 and hourly averaged heat inputs (MMBtu/hr).

3. No change.

4. No change.

5. No change.

E. Notification, Reporting and Recordkeeping

1. No change.

2. The project shall comply with all the applicable requirements of Chapter 62~~17~~, F.A.C., and 40 CFR 60 Subparts A, ~~and~~ GG, Dc, and Kb. The requirements shall include:

a. No change.

b. No change.

c. No change.

d. No change.

e. No change.

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

g. 40 CFR 60.7(c) - By postmarking or delivering a quarterly excess emissions and monitoring system performance report within 30 days after the end of each calendar quarter. This report shall contain the information specified in 40 CFR 60.7(c) and (d). When firing natural gas or fuel oil in the combustion turbines, the NO_x CEMS shall be used in lieu of the water/fuel monitoring system and fuel bound nitrogen (FBN) monitoring required for reporting excess emissions in 40 CFR 60.334(c)(1) (1997 version). The calibration of the water/fuel monitoring device required in 40 CFR 60.335 (c)(2) (1997 version) will be replaced by the 40 CFR 75 certification tests of the NO_x CEMS. Upon request from DEP, the CEMS emission rates for NO_x shall be corrected to ISO conditions to demonstrate compliance with the NO_x standard established in 40 CFR 60.332.

h. A custom fuel monitoring schedule pursuant to 40 CFR 75 Appendix D for natural gas may be used in lieu of the daily sampling requirements of 40 CFR 60.334 (b)(2) provided the following requirements are met:

1. The permittee shall apply for an Acid Rain permit within the deadlines specified in 40 CFR 72.30.

2. The permittee shall submit a monitoring plan, certified by signature of the Designated Representative (DR), that commits to using a primary fuel of pipeline supplied natural gas (sulfur content less than 20 gr/100 scf pursuant to 40 CFR 75.11(d)(2)).

3. Each unit shall be monitored for SO_2 emissions using methods consistent with the requirements of 40 CFR 75 and certified by the USEPA.

This custom fuel monitoring schedule will only be valid when pipeline natural gas is used as a primary fuel. If the primary fuel for these units is changed to a higher sulfur fuel, SO_2 emissions must be accounted for as required pursuant to 40 CFR 75.11(d).

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

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

~~j.~~ k. Rule 62-297.310(6)~~17-297.345~~, F.A.C. -By providing stack sampling facilities where necessary ~~for each turbine and the auxiliary steam boiler~~.

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

3. No change.

4. The following protocols shall be submitted to the Department's Air Program, within the Southwest District office for approval;

a. CEMS Protocol -Within 60 days after selection of the CEMS, but prior to the initial startup, a CEMS protocol describing the system, its installation, operating and maintenance characteristics and requirements. The protocol shall meet the requirements of 40 CFR 60.13, 40 CFR 60 Appendix B and Appendix F or 40 CFR 75. The Federal Acid Rain Program requirements of 40 CFR 75 shall apply when those requirements become effective within the state.

b. Performance Test Protocol - At least 30 ~~90~~ days prior to conducting the initial performance tests required by this permit, FPC shall submit to the Department's Air Program, within the Southwest District office, a protocol outlining the procedures to be followed, the test methods and any differences between the reference methods and the test methods proposed to be used to verify compliance with the conditions of this permit. The Department shall approve the testing protocol provided that it meets the requirements of this permit.

Any party to this Notice has the right to seek judicial review of this Order pursuant to Section 120.68, Florida Statutes, by the filing of a Notice of Appeal, pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the Clerk of the Department of Environmental Protection, Office of General Counsel, 3900 Commonwealth Boulevard, M.S. 35, Tallahassee, Florida 32399-3000 and by filing a copy of the Notice of Appeal accompanied by the applicable filing fee with the appropriate District Court of Appeal. The Notice of Appeal must be filed within 30 days from the date that this Final Order is filed with the Department of Environmental Protection.

DONE AND ENTERED this 27th day of January 1999, in Tallahassee, Florida.

STATE OF FLORIDA, DEPARTMENT OF ENVIRONMENTAL PROTECTION

Kirby B. Green

KIRBY B. GREEN, III
SECRETARY
3900 Commonwealth Boulevard
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Telephone: (850) 488-1554

FILING AND ACKNOWLEDGMENT:
FILED, on this date, pursuant to § 120.52, F. S., with the designated Department Clerk, receipt of which is hereby acknowledged.

Heather Chapman
CLERK

1/27/99
DATE

CERTIFICATE OF SERVICE

I CERTIFY that a true copy of the foregoing Final Order Modifying Conditions of Certification was mailed to the following listed persons on this 27th day of January 1999.

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SUMMARY SHEET

UNIT: PFL–5B

HEATING VALUE: 1.030 BTU/cu. ft.

FUEL: 100 % GAS

SPEC. GRAVITY: 0.582

RUN #	LOAD (MW)	STEAM INJECT. (KPPH)	FUEL FLOW (SCFM)	FUEL FLOW (KPPH)	O2 % dry	CO2 % dry	CO ppmvd	VOC ppmvd	NOx ppmvd @ 15 % O2 ISO Condition
1	155	91	26438	72.1	13.6	4.3	2.5	0.1	38.3
2	155	91	26455	72.2	13.6	4.3	2.1	0.1	39.5
3	155	91	26455	72.2	13.5	4.3	1.1	0.1	39.3
1	119	73	21197	57.8	14.9	3.4	N/A	N/A	25.6
2	119	72	21203	57.8	15.0	3.4	N/A	N/A	27.6
3	119	73	21214	57.9	15.0	3.4	N/A	N/A	28.4
1	81	49	16248	44.3	14.8	3.4	N/A	N/A	27.2
2	81	47	16289	44.4	14.8	3.4	N/A	N/A	28.2
3	80	48	15832	43.2	16.5	2.6	N/A	N/A	26.5
1	53	30	12578	34.3	16.1	2.7	N/A	N/A	26.5
2	52	30	.12535	34.2	16.2	2.6	N/A	N/A	25.9
3	52	30	12508	34.1	16.2	2.6	N/A	N/A	26.2

FUEL: 100 % DISTILLATE

RUN #	LOAD (MW)	STEAM INJECT. (KPPH)	FUEL FLOW (GPM)	FUEL FLOW (KPPH)	O2 % dry	CO2 % dry	CO ppmvd	VOC ppmvd	NOx ppmvd @ 15 % O2 ISO Condition
1	140	136	187	76.9	13.9	5.2	6.9	0.0	42.1
2	140	136	187	76.9	14.0	5.2	6.9	0.0	41.8
3	140	138	187	76.9	13.9	5.2	7.1	1.1	40.9
1	119	88	166	68.2	14.1	5.1	N/A	N/A	53.1
2	119	88	167	68.6	14.1	5.0	N/A	N/A	55.3
3	119	88	166	68.2	14.1	5.1	N/A	N/A	56.9
1	80	57	128	52.6	15.0	4.5	N/A	N/A	49.2
2	80	57	127	52.2	15.0	4.5	N/A	N/A	48.2
3	80	58	128	52.6	15.0	4.4	N/A	N/A	48.4
1	51	34	97	39.9	16.5	3.4	N/A	N/A	48.1
2	51	33	98	40.3	16.4	3.4	N/A	N/A	48.0
3	51	34	98	40.3	16.4	3.4	N/A	N/A	48.2

N/A = Not Applicable

NC Standard (Distillate) = 65 ppmvd
NC Standard (Gas) = 42 ppmvd

C(tandard (Distillate) = 33 ppmvd
CO Standard (Gas) = 30 ppmvd

VOC Standard (Distillate) = 6 ppmvd
VOC Standard (Gas) = 1 ppmvd

SUMMARY SHEET

UNIT: PFL-5A

DATE: 12/15/93

FUEL: 100 % DISTILLATE

RUN #	LOAD (MW)	STEAM INJECT. (KPPH)	FUEL FLOW (GPM)	FUEL FLOW (KPPH)	O2 % dry	CO2 % dry	CO ppmvd	VOC ppmvd	NOx ppmvd @ 15 % O2 ISO Condition
1	141	142	185	76.0	14.3	5.0	6.8	0.1	42.0
2	141	143	186	76.4	14.3	5.0	6.3	0.2	41.8
3	141	141	187	76.9	14.3	5.0	7.6	0.1	43.6
1	119	91	167	68.6	14.9	4.5	N/A	N/A	54.5
2	120	93	168	69.0	14.9	4.5	N/A	N/A	55.2
3	120	93	167	68.6	14.9	4.5	N/A	N/A	53.9
1	80	58	127	52.2	15.2	4.3	N/A	N/A	49.8
2	80	58	127	52.2	15.2	4.3	N/A	N/A	50.3
3	80	57	126	51.8	15.2	4.3	N/A	N/A	50.0
1	51	34	97	39.9	16.6	3.3	N/A	N/A	49.9
2	50	33	97	39.9	16.6	3.3	N/A	N/A	50.6
3	50	33	97	39.9	16.6	3.3	N/A	N/A	50.5

N/A = Not Applicable

NOx Standard (Distillate) = 65 ppmvd

CO Standard (Distillate) = 33 ppmvd

VOC Standard (Distillate) = 6 ppmvd

SUMMARY SHEET

UNIT: PFL-5A

HEATING VALUE: 1.031 BTU/cu. ft.

FUEL: 100 % GAS

SPEC. GRAVITY: 0.582

DATE: 06/29/93

RUN #	LOAD (MW)	STEAM INJECT. (KPPH)	FUEL FLOW (SCFM)	FUEL FLOW (KPPH)	O2 % dry	CO2 % dry	CO ppmvd	VOC ppmvd	NOx ppmvd @ 15 % O2 ISO Condition
1	155	92	26500	72.3	13.5	4.3	1.5	0.0	36.6
2	154	91	26418	72.1	13.5	4.3	2.0	0.0	36.0
3	153	90	26063	71.2	13.5	4.2	1.4	0.0	35.9
1	120	72	21246	58.0	14.0	3.9	N/A	N/A	30.2
2	121	75	21359	58.3	14.1	3.9	N/A	N/A	30.8
3	121	74	21341	58.3	14.1	3.9	N/A	N/A	30.9
1	81	50	16361	44.7	14.8	3.5	N/A	N/A	28.4
2	81	49	16374	44.7	14.8	3.5	N/A	N/A	28.0
3	81	49	16379	44.7	14.8	3.5	N/A	N/A	28.3
1	51	29	12346	33.7	16.4	2.7	N/A	N/A	29.2
2	51	29	12334	33.7	16.4	2.7	N/A	N/A	28.2
3	50	29	12334	33.7	16.4	2.7	N/A	N/A	28.1

FUEL: 100 % DISTILLATE

DATE: 08/02/93

RUN #	LOAD (MW)	STEAM INJECT. (KPPH)	FUEL FLOW (GPM)	FUEL FLOW (KPPH)	O2 % dry	CO2 % dry	CO ppmvd	VOC ppmvd	NOx ppmvd @ 15 % O2 ISO Condition
1									
2									
3									
1									
2									
3									
1	81	58	132	54.3	14.7	4.6	N/A	N/A	46.5
2	80	58	130	53.4	14.7	4.6	N/A	N/A	48.6
3	81	58	131	53.8	14.7	4.6	N/A	N/A	48.9
1	51	32	100	41.1	16.2	3.5	N/A	N/A	43.0
2	51	34	100	41.1	16.2	3.5	N/A	N/A	44.3
3	51	33	101	41.5	16.2	3.5	N/A	N/A	44.1

N/A = Not Applicable

NOx Standard (Distillate) = 65 ppmvd
NOx Standard (Gas) = 42 ppmvd

CO Standard (Distillate) = 33 ppmvd
Standard (Gas) = 30 ppmvd

VOC Standard (Distillate) = 6 ppmvd
VOC Standard (Gas) = 1 ppmvd

SUMMARY SHEET

UNIT: PFL-4B

FUEL: 100 % GAS

HEATING VALUE: 1.026 BTU/cu. ft.

SPEC. GRAVITY: 0.578

RUN #	LOAD (MW)	STEAM INJECT. (KPPH)	FUEL FLOW (SCFM)	FUEL FLOW (KPPH)	O2 % dry	CO2 % dry	CO ppmvd	VOC ppmvd	NOx ppmvd @ 15 % O2 ISO Condition
1	156	92	26650	72.7	13.5	4.2	0.9	0.1	37.4
2	157	92	26783	73.0	13.5	4.2	1.8	0.2	37.4
3	156	92	26765	73.0	13.5	4.2	2.7	0.1	37.7
1	120	74	21462	58.5	14.0	4.0	N/A	N/A	32.3
2	120	74	21484	58.6	14.0	3.9	N/A	N/A	32.0
3	120	74	21549	58.7	14.0	3.9	N/A	N/A	32.2
1	79	48	16199	44.2	15.1	3.3	N/A	N/A	29.2
2	79	48	16225	44.2	15.1	3.3	N/A	N/A	30.2
3	80	48	16250	44.3	15.1	3.3	N/A	N/A	30.7
1	46	25	11857	32.3	16.7	2.4	N/A	N/A	33.0
2	46	26	11933	32.5	16.7	2.4	N/A	N/A	32.7
3	46	27	11930	32.5	16.7	2.5	N/A	N/A	34.5

FUEL: 100 % DISTILLATE

RUN #	LOAD (MW)	STEAM INJECT. (KPPH)	FUEL FLOW (GPM)	FUEL FLOW (KPPH)	O2 % dry	CO2 % dry	CO ppmvd	VOC ppmvd	NOx ppmvd @ 15 % O2 ISO Condition
1	141	141	190	78.1	13.9	5.2	7.3	0.1	39.7
2	141	141	190	78.1	13.9	5.2	7.4	0.1	40.4
3	141	141	190	78.1	14.0	5.2	8.1	0.1	40.0
1	111	82	159	65.3	14.2	5.0	N/A	N/A	52.1
2	111	82	159	65.3	14.2	5.0	N/A	N/A	53.0
3	111	82	159	65.3	14.2	5.0	N/A	N/A	53.0
1	80	56	127	52.2	15.3	4.3	N/A	N/A	50.8
2	80	56	127	52.2	15.3	4.3	N/A	N/A	51.1
3	80	56	127	52.2	15.2	4.3	N/A	N/A	49.9
1	50	32	96	39.5	16.7	3.3	N/A	N/A	50.4
2	50	32	96	39.5	16.7	3.3	N/A	N/A	50.5
3	50	32	96	39.5	16.7	3.2	N/A	N/A	50.1

N/A = Not Applicable

NOx Standard (Distillate) = 65 ppmvd
NOx Standard (Gas) = 42 ppmvd

CO Standard (Distillate) = 33 ppmvd
CO Standard (Gas) = 30 ppmvd

VOC Standard (Distillate) = 6 ppmvd
VOC Standard (Gas) = 1 ppmvd

SUMMARY SHEET

UNIT: PFL-4A

HEATING VALUE: 1.027 BTU/cu. ft.

FUEL: 100 % GAS

SPEC. GRAVITY: 0.577

RUN #	LOAD (MW)	STEAM INJECT. (KPPH)	FUEL FLOW (SCFM)	FUEL FLOW (KPPH)	O2 % dry	CO2 % dry	CO ppmvd	VOC ppmvd	NOx ppmvd @ 15 % O2 ISO Condition
1	158	96	26979	73.7	13.3	4.3	1.0	0.1	35.0
2	158	96	27018	73.8	13.3	4.3	1.7	0.1	35.1
3	158	97	26988	73.7	13.4	4.3	1.2	0.1	35.4
1	121	68	21611	59.0	13.6	4.1	N/A	N/A	33.9
2	121	68	21600	59.0	13.6	4.1	N/A	N/A	34.2
3	121	68	21616	59.0	13.6	4.1	N/A	N/A	34.6
1	80	42	16438	44.9	14.9	3.4	N/A	N/A	31.5
2	80	40	16394	44.8	14.9	3.4	N/A	N/A	31.5
3	80	40	16318	44.6	14.9	3.4	N/A	N/A	31.5
1	50	28	12274	33.5	16.3	2.6	N/A	N/A	26.5
2	50	27	12276	33.5	16.4	2.6	N/A	N/A	27.0
3	50	27	12308	33.6	16.4	2.6	N/A	N/A	27.8

FUEL: 100 % DISTILLATE

RUN #	LOAD (MW)	STEAM INJECT. (KPPH)	FUEL FLOW (GPM)	FUEL FLOW (KPPH)	O2 % dry	CO2 % dry	CO ppmvd	VOC ppmvd	NOx ppmvd @ 15 % O2 ISO Condition
1	140	120	188	77.3	13.8	5.1	11.1	0.1	47.3
2	140	120	188	77.3	13.9	5.1	10.9	0.1	49.8
3	140	140	188	77.3	13.7	5.2	16.8	0.1	37.3
1	119	88	166	68.2	13.9	5.0	N/A	N/A	49.2
2	119	88	166	68.2	14.0	5.0	N/A	N/A	51.3
3	119	88	166	68.2	14.0	5.0	N/A	N/A	51.3
1	80	40	128	52.6	14.9	4.5	N/A	N/A	60.8
2	80	40	128	52.6	14.9	4.4	N/A	N/A	61.9
3	80	40	128	52.6	14.8	4.5	N/A	N/A	62.8
1	50	23	96	39.5	16.4	3.3	N/A	N/A	54.0
2	50	23	96	39.5	16.4	3.3	N/A	N/A	54.6
3	50	23	96	39.5	16.4	3.3	N/A	N/A	55.6

N/A = Not Applicable

NOx Standard (Distillate) = 65 ppmvd
NOx Standard (Gas) = 42 ppmvd

CO Standard (Distillate) = 33 ppmvd
CO Standard (Gas) = 30 ppmvd

VOC Standard (Distillate) = 6 ppmvd
VOC Standard (Gas) = 1 ppmvd

Florida Department of

Memorandum Environmental Protection

TO: Clair Fancy (4 hand delivered by applicant)
Mike Hickey (4)
Geofrey Mansfield (3)
David Bickner (1)
Scott Gorland (1)

RECEIVED

JAN 14 1999

BUREAU OF
AIR REGULATION

FROM: Steve Palmer
Siting Coordination Office

DATE: January 11, 1999

SUBJECT: Florida Power Corporation Supplemental Power Plant Site Certification Application (Hines Energy Complex); PA 92-33 (Module 8043).

Attached is a copy of the Florida Power Corporation Supplemental Site Certification Application (SCA). This is a proposed 500 MW (nominal) facility utilizing two combustion turbines, two heat recovery steam generators, and one steam turbine. The combustion turbines will be fueled with natural gas with fuel oil as a backup fuel. This application represents the second power block for a site that has been certified for an ultimate capacity of 3000 MW.

Please review this SCA for sufficiency and return your comments to me by February 15, 1999. If sufficiency questions can be timely resolved, reports will be due to the Siting Coordination Office on June 3, 1999.

If you have any questions, please call me at 850/487-0472.

Attachment --

PREVENTION OF SIGNIFICANT DETERIORATION PERMIT
APPLICATION FOR FLORIDA POWER CORPORATION (FPC)
HINES ENERGY COMPLEX
POWER BLOCK 2

TABLE OF CONTENTS

TABLE OF CONTENTS (Continued)

FIGURES

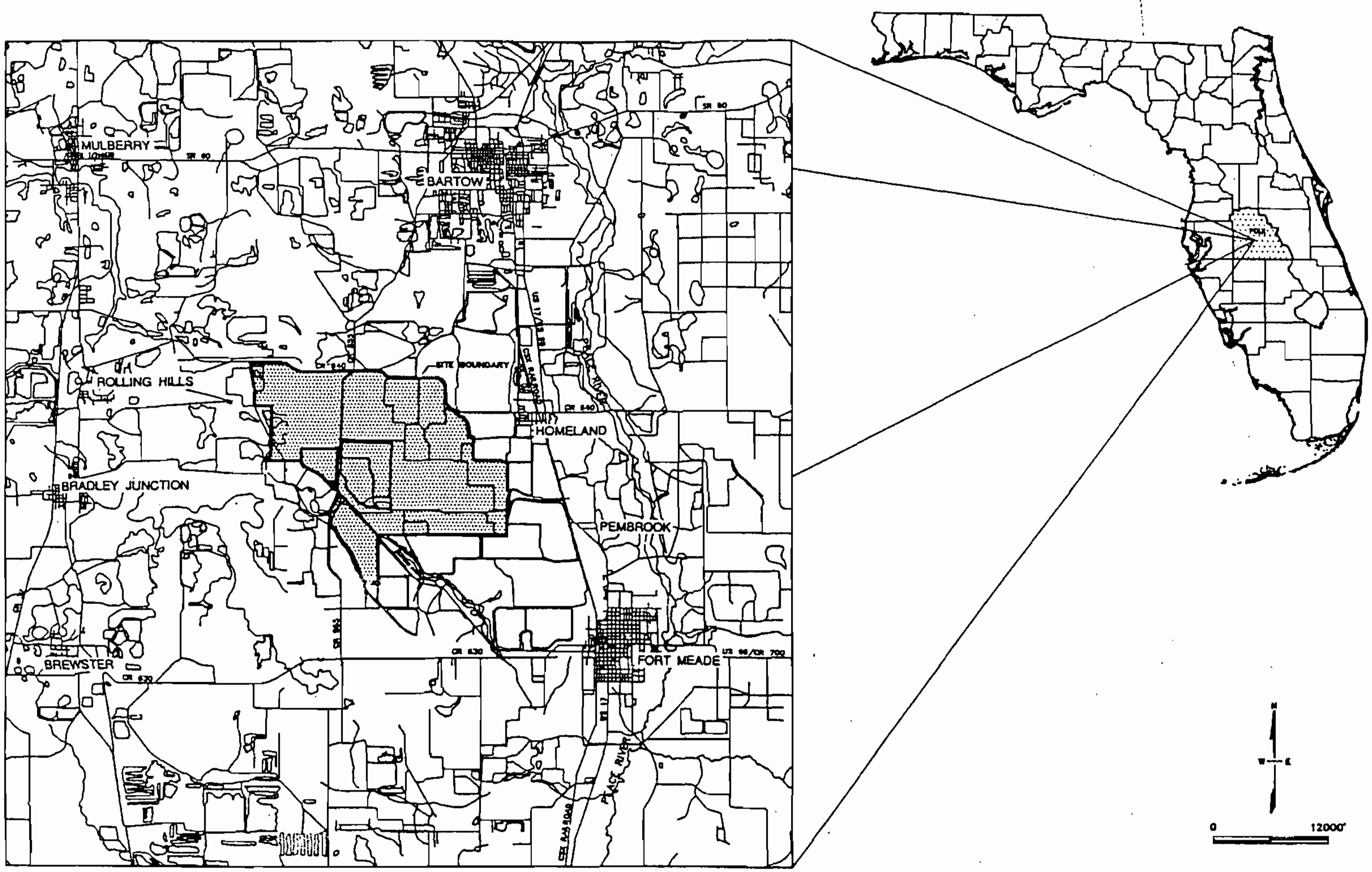
1.0 INTRODUCTION

Florida Power Corporation (FPC) has recently begun operation of Power Block 1, 485 megawatts (MW-nominal 500 MW) of combined cycle power generation. The generating units are located in the southwest portion of Polk County, about seven miles south-southwest of Bartow and five miles west-northwest of Fort Meade (see Figure 1-1). Future generating units are to be brought on-line sequentially, with the scheduling of units to match the estimated growth of demand through the ultimate site capacity of up to 3,000 MW. The expansion of generating capacity at the Hines Energy Complex will be accomplished using the most efficient generating technology throughout the life of the project. This approach offers FPC maximum flexibility and cost control as both technology advances and electrical demand increases.

Power Block 2 consists of two nominal 165 MW Westinghouse 501 F combustion turbines (CTs), two unfired heat recovery steam generators (HRSGs), and one nominal 170 MW steam turbine generator (STG); i.e., a two-on-one configuration. The total nominal rating for Power Block 2 is approximately 500 MW. Pipeline quality natural gas will be utilized as the primary fuel with limited use of low sulfur fuel oil as the back-up fuel. Among the advantages of this combined cycle (CC) technology are its fuel flexibility, modularity, and efficiency. Because of the modularity of CC units, they can be sized and built incrementally to match demand without losing the economy of scale. Applications for the remaining site capacity will be submitted in the future, as appropriate.

The U.S. Environmental Protection Agency (EPA) has promulgated Prevention of Significant Deterioration (PSD) regulations (40 CFR 51.166), which require a permit review and approval for new or modified sources that increase air pollutant emissions above specified threshold levels. These emission threshold levels will be exceeded for several criteria pollutants during operation of Power Block 2. As a result, Power Block 2 is subject to PSD review for these pollutants. The Federal PSD regulations are implemented in

Florida by the Florida Department of Environmental Protection (FDEP). FDEP's PSD regulations are codified in Rule 62-212.400 F.A.C. The technical information and analysis required by the federal and state PSD regulations are contained in this PSD permit application. Although this document will be an appendix to the Site Certification Application (SCA) and only addresses Power Block 2, it has been prepared as a stand-alone PSD permit application. The permit application is divided into eight major sections. Presented in Section 2.0 is a description of the facility, including air pollutant emissions and stack parameters. Air quality review requirements and applicability are presented in Section 3.0. The best available control technology (BACT) evaluation is presented in Section 4.0. An ambient air quality monitoring data analysis is presented in Section 5.0, and the air quality modeling methodology, the results of the air quality impact assessment, and additional impacts analysis performed for the proposed project are presented in Sections 6.0, 7.0, and 8.0, respectively. Section 9.0 contains a list of references and materials cited.



SOURCE: 1992 SCA

Florida Power CORPORATION

Hines Energy Complex

FIGURE 1-1
SITE LOCATION MAP

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2.1 GENERAL DESCRIPTION

The proposed Power Block 2 project will consist of the construction of approximately 500 MW of generation. The CC configuration consists of two CTs, two HRSGs, and one steam turbine. In this "two-on-one" configuration, each of the two CTs are nominally rated at 165 MW, and the steam turbine has a nominal rating of 170 MW. Each CT will be served by a single HRSG, exhausting to an individual stack. There will be no HRSG bypass stacks for simple cycle operation. Also, there will be no supplemental firing of the HRSGs. The expected primary fuel is natural gas, with low sulfur fuel oil as a backup.

The CC units will utilize low sulfur fuel to limit sulfur dioxide (SO_2) emissions and sulfuric acid mist, selective catalytic reduction (SCR) to limit emissions of oxides of nitrogen (NO_X), and good combustion practices and clean fuels for the minimization of particulate matter (PM/PM_{10}), carbon monoxide (CO), volatile organic compounds (VOCs), and other (trace metals) emissions. The proposed emission control techniques are described in detail in Section 4.0 of this application.

2.2 PROPOSED SOURCE EMISSIONS AND STACK PARAMETERS

As the steam turbine is not a combustion source, estimated mass emissions are based on operation of only the CTs. However, the exhaust gas characteristics reflect flow through the HRSG (i.e., the characteristics reflect the impact of the steam turbine). Therefore, the estimated stack emissions that are representative of the advanced CT designs proposed for Power Block 2 are presented in Tables 2-1 and 2-2 for a 165 MW CT unit. The exhaust parameters presented in these tables are reflective of the combined cycle configuration. These tables cover the natural gas and fuel oil cases for three ambient temperatures: 1) the high temperature case of 105°F, 2) the ISO reference temperature case of 59°F and 3) the low temperature case that represents the shaft limit or the maximum physical output of the equipment, i.e., 22°F for oil and 32°F for natural gas. Maximum hourly emission rates for all pollutants, in units of pounds per hour (lb/hr) are projected to occur for operations at low ambient temperature and base load. Maximum annual potential emission rates (after the application of BACT) for the proposed sources with respect to regulated criteria air pollutants and regulated non-criteria air pollutants are presented in Table 2-3.

Worst-case air quality impacts due to the proposed facility are a function of emission rate and plume rise. Although it is not practical to model all possible operating scenarios for the facility, a number of cases (combinations of operating conditions and fuel types) were examined to represent the range that will occur during actual operations. The low (22°F and 32°F for oil and gas, respectively) and high (105°F) ambient temperatures are reasonable points selected to indicate the influence of compressor inlet temperature on combustion turbine performance and emissions/exhaust characteristics. At high ambient temperature, the units cannot generate as much power because of lower compressor inlet density. To compensate for a portion of the loss of output (which can be on the order of 20 MW compared to referenced temperatures), inlet cooling is proposed to be installed ahead of the combustion turbine inlet. Therefore, the 59°F temperature case represents a conservative average temperature condition for estimating annual emissions for Power Block 2, inclusive of potential inlet cooling.

A review of the CT unit design information in Tables 2-1 and 2-2 indicates that the highest criteria air pollutant emission rates (SO_2, PM/PM_{10}, NO_X, CO, and VOCs) occur when burning fuel oil. Combustion of fuel oil also results in higher exhaust gas flow rates and stack exit temperatures, which are directly related to plume rise. Although the highest emission rates occur under the low temperature (22°F) condition, the lowest exhaust gas volumetric flow rate for the CC units occurs under the 105°F ambient temperature condition. Detailed discussion on the determination of worst-case impacts is presented in Section 6.0 (Air Quality Modeling Methodology).

Typical fuel analyses for natural gas and fuel oil are presented in Tables 2-4 and 2-5, respectively. For oil firing, it is requested that an aggregate annual fuel usage for Power Block 2 of 13,762,806 gallons be included as a permit condition. This equates to a maximum of 1,000 hours per year of generation at full load (59° F). This amount is the same as authorized for Power Block 1.

FPC is requesting that the fuel-bound nitrogen allowance be added to the permitted NO_x emission rate while firing fuel oil. The allowance would account for fuel-bound nitrogen up to 0.030%, resulting in permitted emissions ranging from the baseline of 42 ppm (303 lb/hour, 152 tons/year) for a fuel-bound nitrogen content of 0.015% to 48 ppm (346 lb/hour, 174 tons/year) for a fuel-bound nitrogen content of 0.030%.

2.3 SITE LAYOUT AND STRUCTURES

The site arrangement for the initial nominal 1,000 MW (combined Power Blocks 1 and 2) is depicted in Figure 2-1. This configuration arrangement includes the existing 485 MW CC unit, as well as the proposed 500 MW Power Block 2, each with two CTs, two HRSGs, and one steam turbine. The four HRSG stacks are arranged in an east-west line. The flow diagram for a single 250 MW CC unit is depicted in Figure 2-2.

Stack sampling facilities will be constructed in accordance with Rule 62-297.310(6) F.A.C.

TABLE 2-1

COMBUSTION TURBINE UNIT (165 MW)

ESTIMATED [1] PERFORMANCE ON NATURAL GAS

CONDITIONS			
Ambient Temperature (°F)	32	59	105
Ambient Relative Humidity (%)	60	60	60
Load Condition (%)	100	100	100
Elevation (ft) (above MSL)	163	163	163
Maximum Heat Input Rate (MMBtu/hr)[2]	1,946	1,822	1,626
EMISSIONS (lb/hr)			
Carbon Monoxide (25 ppm)	91	86	75
Nitrogen Oxides (at 15% O_2) (6 ppmvd)[3]	45	42	38
Sulfur Dioxide	6.0	5.5	5.0
Particulate Matter (PM_{10})	9.8	9.3	8.5
Opacity (%)	10	10	10
Volatile Organic Compounds (8 ppmvd)	17	16	14
Lead	Neg.	Neg.	Neg.
Sulfuric Acid Mist	0.60	0.55	0.50
STACK PARAMETERS			
Stack Height (ft)	125	125	125
Stack Diameter (ft)	19.0	19.0	19.0
Stack Gas Temperature (°F)	206	206	206
Stack Gas Exit Velocity (ft/sec)	64	61	55

Notes: (1) Emission estimates based on manufacturer's data

(2) For CTs the heat-input rate is based on the higher heating value (HHV) of the fuel (1,050 Btu/SCF).

(3) Not corrected to ISO conditions.

MSL = Mean Sea Level   Neg. = Negligible

TABLE 2-2
COMBUSTION TURBINE UNIT (165 MW)
ESTIMATED [1] PERFORMANCE ON FUEL OIL

CONDITIONS			
Ambient Temperature (°F)	22	59	105
Ambient Relative Humidity (%)	60	60	60
Load Condition (%)	100	100	100
Elevation (ft) (above MSL)	163	163	163
Maximum Heat Input Rate (MMBtu/hr)[2]	1,943	1,776	1,581
EMISSIONS (lb/hr)			
Carbon Monoxide (30 ppm)	113	92	92
Nitrogen Oxides[3] (42 ppmvd)	332	303	270
Sulfur Dioxide	104	95	84
Particulate Matter (PM_{10})	46	43	37
Opacity (%)	20	20	20
Volatile Organic Compounds (11 ppmvd)	24	22	19
Lead [4]	0.016	0.0146	0.0136
Sulfuric Acid Mist	10	9	8
STACK PARAMETERS			
Stack Height (ft)	125	125	125
Stack Diameter (ft)	19.0	19.0	19.0
Stack Gas Temperature (°F)	289	289	289
Stack Gas Exit Velocity (ft/sec)	74	69	62

Notes: (1) Emission estimates based on manufacturer's data.
(2) For CTs the heat input rate is based on the higher heating value (HHV) of the fuel (19,200 Btu/lb).
(3) Does not include FBN content correction.
MSL = Mean Sea Level Neg. = Negligible

TABLE 2-3

MAXIMUM POTENTIAL ANNUAL EMISSIONS (500 MW) AND PSD SIGNIFICANCE VALUES

Pollutant	Emissions (TPY) *	PSD Significant Emission Rate (TPY)	PSD Review Required (Yes/No)
Carbon Monoxide	756	100	Yes
Nitrogen Oxides	499	40	Yes
Sulfur Dioxide	93	40	Yes
Particulate Matter (PM_{10})	98	15	Yes
Total Suspended Particulates	98	25	Yes
Volatile Organic Compounds	143	40	Yes
Lead	0.016	0.6	No
Sulfuric Acid Mist	9.5	7	Yes

* TPY = Tons per year for the proposed Power Block 2 project.

Basis: Full-load operation; 100% capacity factor; 59°F; 1,000 total hours on fuel oil between the two CTs; 8,260 hours per CT on gas.

TABLE 2-4

TYPICAL NATURAL GAS ANALYSIS

ANALYSIS	MOLE (%)
Carbon Dioxide	0.873
Ethane	2.824
Hexanes Plus	0.116
Iso-Butane	0.175
Methane	94.850
Nitrogen	0.235
Normal-Butane	0.148
Pentanes Plus	0.085
Propane	0.696
Total:	100.000
Specific Gravity (air at 1)	0.71
Quality Information	**Parameters**
Heating Value (HHV)	1050 Btu/cf
Total Sulfur (Maximum)	1 grain/100 SCF

Source: Florida Gas Transmission

TABLE 2-5 TYPICAL NO. 2 FUEL OIL ANALYSIS	
NO. 2 DISTILLATE OIL	PERCENT (BY WEIGHT)
Carbon	85.5
Hydrogen	12.7
Nitrogen	0.2*
Oxygen	1.5
Sulfur	0.05**
Ash	0.01

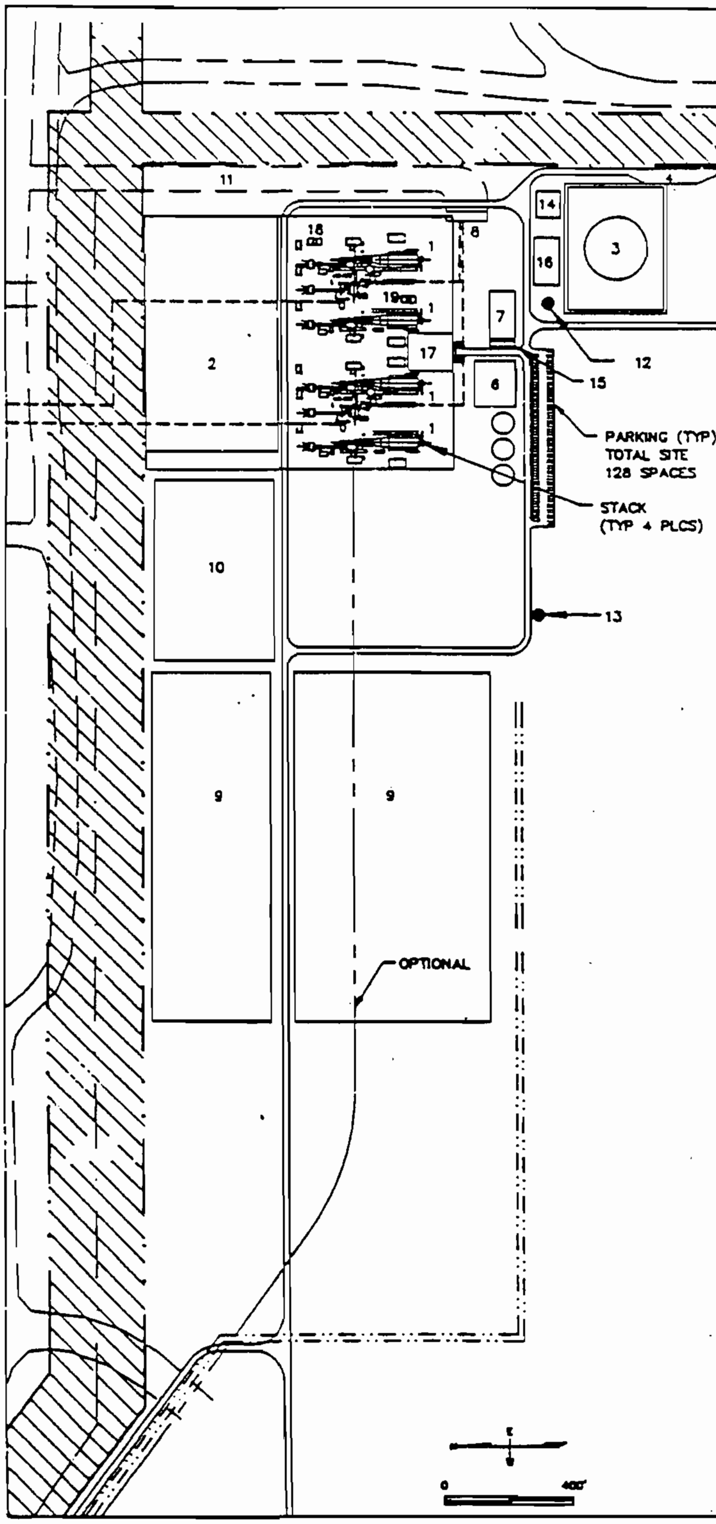
Lower Heating Value: 18,550 Btu/lb

Higher Heating Value: 19,200 Btu/lb

*This is a typical FBN Value. FPC has requested an emissions allowance for FBN of up to 0.030 %, by weight.

**The sulfur content is the maximum, as required by permit.

Source: FPC, 1998



FACILITIES LEGEND

1. COMBUSTION TURBINE COMBINED CYCLE UNIT
2. SWITCHYARD
3. FUEL OIL TANKS AND CONTAINMENT
4. FUEL OIL UNLOADING FACILITY (TRUCK)
5. NOT USED
6. WATER TREATMENT BUILDING
7. WAREHOUSE
8. CIRCULATING WATER INTAKE STRUCTURE
9. CONSTRUCTION LAYDOWN AREA
10. CONSTRUCTION PARKING AREA
11. CIRCULATING WATER INLET CHANNEL
12. WATER SUPPLY WELL 1
13. WATER SUPPLY WELL 2
14. TEMPORARY CONSTRUCTION BUILDING & POWER TRANSFORMERS
15. VEHICULAR FUEL STORAGE
16. SEWAGE TREATMENT PLANT
17. CC CONTROL/ADMIN BUILDING
18. DIESEL GENERATOR
19. AUXILIARY BOILER

SOURCE: 1992 SCA

Florida Power CORPORATION

HINES ENERGY COMPLEX

FIGURE 2-1 SITE ARRANGEMENT (940 MW)

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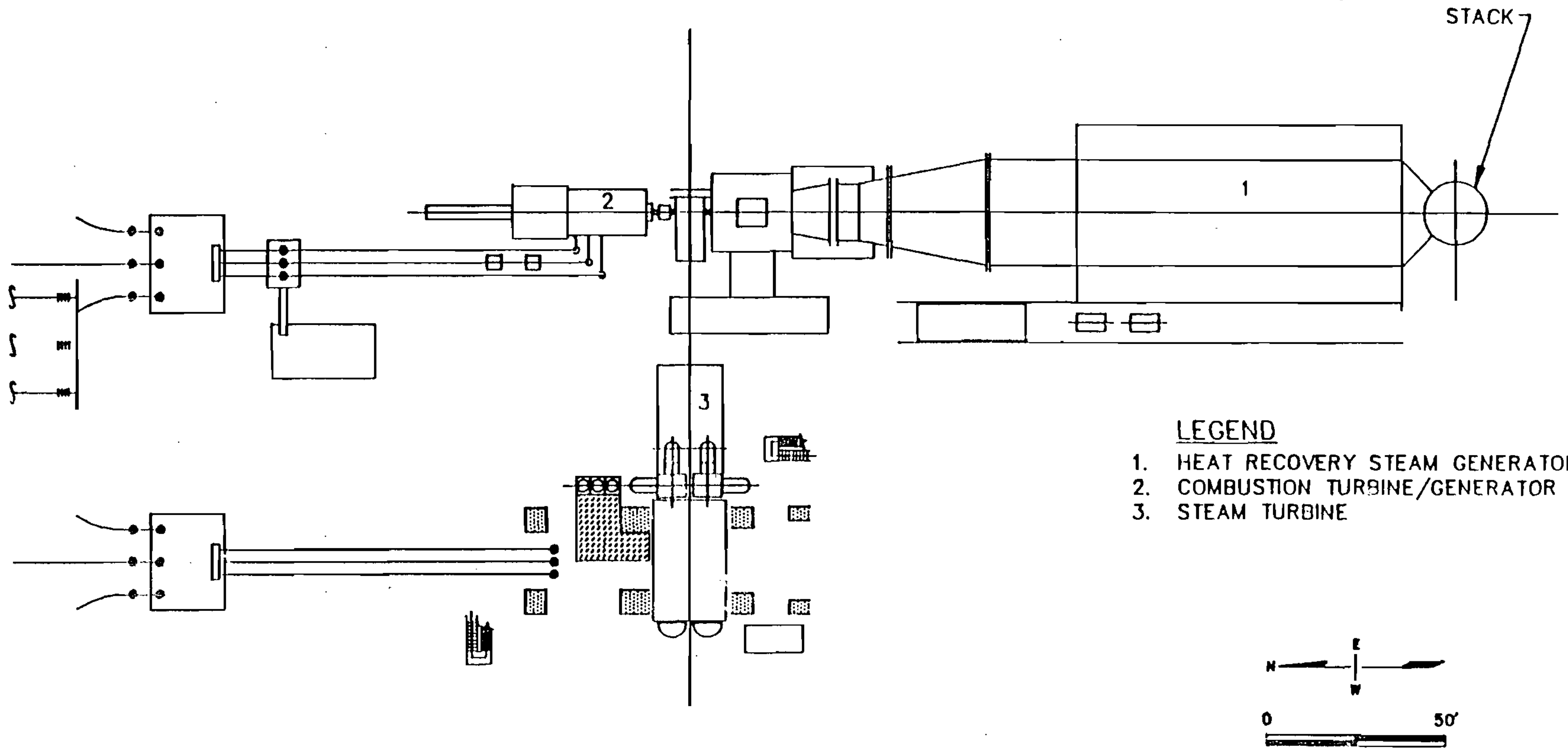

SOURCE: 1992 SCA

Florida Power
CORPORATION
HINES ENERGY COMPLEX

FIGURE 2-2
LAYOUT FOR ONE CC UNIT
(235 MW)

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3.0 AIR QUALITY REVIEW REQUIREMENTS AND APPLICABILITY

The following discussion pertains to the federal and state air regulatory requirements and their applicability to Power Block 2. These regulations must be satisfied before the proposed facility can be constructed and begin operation.

3.1 NATIONAL AND FLORIDA AMBIENT AIR QUALITY STANDARDS (NAAQS/FAAQS)

The applicable federal and state ambient air quality standards are presented in Table 3-1 (PSD increments are also presented in Table 3-1, but discussed in Section 3.2.2). The primary National Ambient Air Quality Standards and Florida Ambient Air Quality Standards (NAAQS/FAAQS) were promulgated to protect the public health, and the secondary NAAQS/FAAQS were promulgated to protect the public health and welfare from any known or anticipated adverse effects associated with the presence of pollutants in the ambient air. Polk County is an attainment area for all criteria pollutants, meaning that existing ambient concentrations meet the allowable standards.

3.2 PSD REVIEW REQUIREMENTS

3.2.1 General Requirements

Under the federal and FDEP Prevention of Significant Deterioration (PSD) permit review requirements, all major new or modified existing sources of air pollutants located in attainment areas and regulated under the Clean Air Act (CAA) must be reviewed and approved. A "major stationary source" is defined as any one of 28 specified source categories which has the potential to emit 100 tons per year (TPY) or more, or any other stationary source which has the potential to emit 250 TPY or more of any air pollutant regulated under the CAA. Fossil fuel-fired steam electric plants of more than 250 MMBtu/hr of heat input comprise one of the 28 specified source categories. As Power Block 2 constitutes a modification to an existing major source, the proposed project "potential to emit" is compared to the PSD significant emission rates (TPY). The term "potential to emit" means the capability, at maximum design capacity, to emit a pollutant after the application of control equipment. As presented earlier in Table 2-3, the potential emissions from the proposed project will exceed the significance rates for all criteria pollutants; therefore, the project is considered a modification to an existing major stationary source and is subject to PSD review.

PSD review is used to ensure that significant air quality deterioration will not result from the new or modified source located in an attainment area. The PSD regulations are contained in rule 62-212.400 F.A.C. Major sources and modifications are required to undergo the following analyses under PSD for each air pollutant emitted where potential emissions exceed the significant emission rates:

- A control technology analysis;
- An air quality impacts analysis; and
- An additional impacts analysis.

In addition to these analyses, a new source must also be reviewed with respect to Good Engineering Practice (GEP) stack height regulations (EPA, 1985a), New Source Performance Standards (NSPS), and any applicable state emission standard as discussed in Section 3.3.

3.2.2 PSD Increments/Classifications

In promulgating the 1977 Clean Air Act (CAA) Amendments, Public Law 95-95, Congress specified that certain increases above an air quality "baseline concentration" level for SO_2 and TSP concentrations would constitute "significant deterioration." The magnitude of the allowable increment depends on the classification of the area in which a new source (or modification) will be located or have a significant impact. Three classifications were designated based on criteria established in the CAA Amendments. Initially, Congress designated PSD areas as Class I (international parks, national wilderness areas, and memorial parks larger than 5,000 acres, and national parks larger than 6,000 acres) or as Class II (all areas not designated as Class I). No Class III areas, which would allow greater deterioration than Class II areas, were designated. EPA subsequently incorporated the requirements for classifications and area designation into the PSD regulations.

On October 17, 1988, the EPA promulgated regulations to prevent significant deterioration due to NO_X emissions and established PSD increments for NO_2 concentrations. The allowable PSD increments for SO_2, TSP, and NO_2 are presented in Table 3-1. The FDEP has adopted the EPA PSD classification scheme and the allowable PSD increments for SO_2, PM_{10}, and NO_2.

The term "baseline concentration" is derived from federal and state PSD regulations and denotes a concentration level corresponding to a specified baseline date and contributions from certain additional baseline sources. The PSD regulations (40 CFR 51.166) define baseline concentration as the ambient concentration level which exists in the baseline area at the time of the applicable baseline date. Emission increases after the baseline date consume PSD increments. A baseline concentration is determined for each pollutant for which PSD increments are promulgated and a baseline date is established. The baseline concentration includes:

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

- The allowable emissions of major stationary sources which commenced construction before January 6, 1975, for SO_2 and PM_{10} concentrations, or before February 8, 1988, for NO_2 concentrations, but which were not in operation by the applicable baseline date.

The air quality analysis results which demonstrate project compliance with these requirements are presented in Section 7.0.

3.2.3 Control Technology

The control technology review requirements of the PSD regulations require that all applicable federal and state emission limiting standards be met and that Best Available Control Technology (BACT) be applied to control emissions from the source. The BACT requirements apply to all applicable regulated and unregulated air pollutants for which the increase in emissions from the source or modification exceeds significant emission rate.

BACT is defined in rule 62-210.200 F.A.C. as:

> An emission limitation, including a visible emissions standard, based on the maximum degree of reduction of each pollutant emitted which the Department, on a case by case basis, taking into account energy, environmental and economic impacts, and other costs, determines is achievable through application of production processes and available methods, systems and techniques (including fuel cleaning or treatment or innovative fuel combustion techniques) for control of each such pollutant.
>
> (a) If the Department determines that technological or economic limitations on the application of measurement methodology to a particular part of an emission unit or facility would make the imposition of an emission standard infeasible, a design, equipment, work practice, operational standard or combination thereof, may be prescribed instead to satisfy the requirement for the application of BACT. Such standard shall, to the degree possible, set forth the emissions reductions achievable by implementation of such design, equipment, work practice or operation.
>
> (b) Each BACT determination shall include applicable test methods or shall provide for determining compliance with the standard(s) by means which achieve equivalent results.

The requirements for BACT were incorporated within the PSD framework in the 1977 CAA Amendments. The primary purpose of BACT is to minimize consumption of PSD increments and thereby increase the potential for future economic growth without significantly degrading air quality. Guidelines for the evaluation of BACT can be found in the draft "New Source Review Workshop Manual" (EPA, 1990b) and the draft "Top-Down BACT Guidance Document" (EPA, 1990c). These guidelines were issued by EPA to provide a consistent approach to BACT and to ensure that the impacts of alternative emission control systems are measured by the same set of parameters. The "top-down" approach to BACT has been followed in this application. BACT is determined on a case-by-case basis, and BACT for a source in one area may not be the same for an identical source located in another area. BACT analyses for the same types of emissions units and the same pollutants in different locations or situations may determine that different control strategies should be applied to the different sites, depending on site-specific factors.

The BACT requirements are intended to ensure that the control systems incorporated in the design of a proposed facility reflect the latest in control technologies used in a particular industry and take into consideration existing and future air quality in the vicinity of the proposed facility. BACT must, at a minimum, demonstrate compliance with NSPS for a source (if applicable). An evaluation of the air pollution control techniques and systems, including a cost-benefit analysis of alternative control technologies capable of achieving a higher degree of emission reduction than the proposed control technology, is required. The cost-benefit analysis requires the documentation of the materials, energy, and economic penalties associated with the proposed and alternative control systems, as well as the environmental benefits derived from these systems. A determination of BACT is to be based on sound judgement, balancing environmental benefits with energy, economic, and other impacts. Section 4.0 presents the BACT discussion and recommendations for this project.

3.2.4 Ambient Air Quality Monitoring Requirements

In accordance with the requirements of Rule 62-212.400(5)(f) F.A.C., any application for a PSD permit must contain an analysis of ambient air quality monitoring data in the area affected by the proposed major stationary source or major modification.

In accordance with Rule 62-212.400(5)(f)(2), ambient air monitoring for a period of up to one year may be required to satisfy the PSD monitoring requirements. A minimum of four months of data would be required. Existing data from the vicinity of the proposed source may be utilized if the data meet certain quality assurance requirements; otherwise, additional data may need to be gathered.

However, the FDEP PSD regulations include an exemption which excludes or limits the pollutants for which an ambient air quality analysis must be conducted (Rule 62-212.400(3)(e)). This exemption states that a proposed major stationary source or major modification from the monitoring requirements with respect to a particular pollutant if the emissions increase of the pollutant from the source or modification would cause, in any area, air quality impacts less than the *de minimis* air quality impact levels presented in Table 3-2.

Ambient air quality monitoring data is discussed in Section 5.0 of this application.

3.2.5 Source Impact Analysis

A source impact analysis of air quality must be performed for a proposed major source subject to PSD for each air pollutant for which the increase in emissions exceeds the significant emission rate. The PSD regulations specifically require the use of atmospheric dispersion models in performing air quality impact analysis, estimating baseline and future air quality levels, and determining compliance with NAAQS/FAAQS and allowable PSD increments. Reference EPA models must normally be used in performing the impact analysis. Use of nonreference EPA models requires EPA's consultation and prior approval. Guidance for the regulatory application of dispersion models is presented in the U.S. EPA "Guideline on Air Quality Models (Revised)" (EPA, 1997). The modelling methodology utilized for the source impact analysis is described in detail in Section 6.0 of this application.

3.2.6 Additional Impacts Analysis

In addition to air quality impact analyses, the PSD regulations require analyses of the impairment to visibility and the impacts on soils and vegetation that would occur as a result of the proposed source. These analyses are to be conducted primarily for PSD Class I areas. Impacts on air quality due to general commercial, residential, industrial, and other growth related activities associated with the source must also be addressed. These analyses are required for each pollutant emitted in significant quantities. Section 8.0 of this application contains the additional impact analyses.

3.3 OTHER REQUIREMENTS

In addition to the requirements of the PSD program, any new or modified source of air pollution must be reviewed with respect to the GEP stack height regulations (EPA, 1985a), the federal NSPS requirements, and any state-specific emission standards.

3.3.1 Good Engineering Practice (GEP) Stack Height

The 1977 CAA Amendments require under Section 123 that the degree of emission limitation required for control of any air pollutant not be affected by a stack height that exceeds GEP, or any other dispersion technique. On July 8, 1985, EPA promulgated final stack height regulations (EPA, 1985a).

The EPA's final stack height regulations define GEP stack height in part as the greater of:

(1) 65 meters, measured from the ground-level elevation at the base of the stack; or

(2) $H_g = H + 1.5\ L$

where:

H_g = GEP stack height, measured from the ground-level elevation at the base of the stack;

H = Height of nearby structure(s) measured from the ground-level elevation at the base of the stack; and

L = Lesser dimension, height or projected width of nearby structure(s).

The term "nearby" is defined by the GEP stack height regulations as a distance up to five times the lesser of the height or width dimensions of a structure or terrain feature, but not greater than 0.8 km. Although GEP stack height regulations require that the stack height credit used in modelling for determining compliance with NAAQS/FAAQS and PSD increments not exceed the GEP stack height, the actual stack height may be greater. In this case the proposed stacks for the 500 MW (nominal) generating units are 125.0 feet (38.1 meters) above ground level. This height does not exceed the de minimus GEP stack height of 65m. See Section 6.7 of this application for a discussion of building downwash considerations for this project.

3.3.2 New Source Performance Standards (NSPS)

The CAA required the U.S. EPA to adopt standards of performance for new or modified stationary sources of air pollution. To date, the U.S. EPA has adopted regulations for approximately 80 stationary source categories. These regulations are contained in 40 CFR Part 60. A review of the regulations reveals that the Power Block 2 CC units are subject to a specific NSPS. Any source subject to a specific NSPS is also subject to the general provisions of 40 CFR 60 Subpart A.

3.3.2.1 General Provisions

The general provisions of the NSPS regulations are found in 40 CFR 60, Subpart A. The general provisions specify the notification and record keeping requirements (40 CFR 60.7), compliance with standards and maintenance requirements (40 CFR 60.11), and the monitoring requirements (40 CFR 60.13) for each affected source.

3.3.2.2 Combined Cycle Units

NSPS for combined cycle units are covered in 40 CFR 60 and potentially include: Subpart Da - Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978; in 40 CFR 60, Subpart Db - Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units; and in 40 CFR 60, Subpart GG - Standards of Performance for Stationary Gas Turbines. Because the steam generators associated with Power Block 2 (i.e., HRSGs) will utilize only the waste heat from the combustion turbines, only the requirements of Subpart GG and Subpart A will apply.

Subpart GG regulates the CC units as electric utility stationary gas turbines and establishes emission limitations on both NO_x and SO_2. The NO_x emission limitation is set by the following equation:

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

where:

STD = allowable NO_X emissions (percent by volume at 15 percent oxygen and on a dry basis).

Y = manufacturer's rated heat rate at manufacturer's rated load (kilojoules per watt hour) or actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour.

F = NO_X emission allowance for fuel-bound nitrogen as defined below:

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

where:

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

This results in an emission limitation of 113.5 parts per million on a dry volume basis (ppmvd) at 15 percent oxygen for the proposed units when fired on natural gas and 112.7 ppmvd at 15 percent oxygen when fired on fuel oil. (These values do not include the allowance for fuel-bound nitrogen). The SO_2 emission limitations are set at 150 ppmvd corrected to 15 percent oxygen in the exhaust stream or a fuel sulfur content less than or equal to 0.8 percent by weight.

40 CFR 60 Subparts Da, Db, and Dc are not applicable to the CC units since the HRSGs will not be fired with any type of auxiliary fuel.

3.3.2.3 Excess Emissions

The EPA has adopted general and specific recordkeeping and reporting requirements relating to excess emissions in 40 CFR 60.7(b) and 40 CFR 60.334(c). The EPA requirements specify maintaining records and submittal of a quarterly report (calendar year) on excess emissions associated with start-ups, shutdowns, malfunctions, inoperative continuous emission monitoring systems, low water-to-fuel ratio, and fuel sulfur content greater than 0.8% by weight. The reporting requirement includes submittal of the quarterly report even when no excess emissions occur. EPA has not adopted any specific time limits related to excess emissions from a CC unit, or from combustion turbine units regulated under 40 CFR Part 60, Subpart GG.

3.3.3 State-Specific and General Emission Standards

In addition to federal requirements, FDEP has adopted specific and general emission limiting and performance standards. These standards may be found in rule 62-296, F.A.C. The requirements of these standards must be met along with any federal PSD or NSPS limitation or requirement.

3.3.3.1 General Emission Standards

The FDEP has adopted general particulate matter emission limits as well as general pollutant emission limits (rule 62-296.320, F.A.C.). These limits apply when no specific emission standard is applicable.

3.3.3.2 Combined Cycle Units

The FDEP has not adopted any state-specific emission standards in rule 62-296, F.A.C. relating to the operation of a CC unit. The FDEP has adopted the NSPS requirements of Subparts A and GG by reference in rule 62-204.800, F.A.C. Based on the current FDEP rules, the CC units must meet the NSPS requirements as discussed in Section 3.3.2.2. In addition, a general opacity limit of less than 20 percent and a prohibition on emitting air pollutants that cause or contribute to an objectionable odor apply.

FPC is requesting that the DEP add the fuel-bound nitrogen allowance to the emissions limit for NO_x. This request is discussed in more detail in Section 2.2 and Section 4 of this Appendix.

3.3.3.3 Excess Emissions

The FDEP has adopted standards relating to excess emissions in rule 62-210.700, F.A.C. The rule allows excess emissions resulting from startup, shutdown, or malfunction of any source as long as best operational practices are applied and the excess emissions do not exceed 2 hours in any 24 hour period. Currently, the rule allows one exception from the 2 hour limit and that is for existing fossil fuel steam generators. The FDEP can authorize different excess emission parameters for other sources on a case-by-case basis. Based on the intended operation of the CC units, it is requested that the FDEP consider the operational variations of this equipment as well as the EPA's NSPS requirements on excess emissions and set an allowable excess emissions level as follows:

> "Excess emissions from a combined cycle unit resulting from startup, shutdown, fuel switch, or malfunction shall be permitted for up to three (3) hours provided that best operational practices to minimize excess emissions are adhered to and the duration of the excess emissions shall be minimized."

3.4 SOURCE APPLICABILITY

3.4.1 Pollutant Applicability

The PSD regulations apply to the proposed generation project due to the attainment status for the Polk County Site. Polk County and the surrounding counties are designated as PSD Class II areas for SO_2, PM_{10}, and NO_2. The Polk County Site is located approximately 118 km southeast of the Chassahowitzka Wilderness Area, the nearest PSD Class I area. The Chassahowitzka Wilderness Area is that portion of the Chassahowitzka National Wildlife Refuge which has been officially designated as wilderness.

Pollutant applicability for the proposed facilities is addressed in Sections 2.0 and 4.0 and briefly summarized here. The proposed Power Block 2 project is considered to be a modification to an existing major source under the PSD regulations. PSD review is required for any regulated pollutant for which the net increase in emissions exceeds the PSD significant emission rates presented in Table 2-5. As shown, the potential emissions for the proposed facilities will exceed the PSD significant emission rates for the following regulated pollutants: CO, NO_X, SO_2, PM_{10}, VOC, and sulfuric acid mist. The proposed project is subject to PSD review for these pollutants.

3.4.2 Ambient Air Quality Monitoring

Based upon the net increase in emissions from the proposed facility presented in Table 2-3, a PSD preconstruction ambient air monitoring analysis is required, as part of the air quality impact analysis for CO, NO_2, SO_2, PM_{10}, O_3 (based on VOC emissions), and sulfuric acid mist. However, if the net increase in a source's impact of a pollutant is less than the *de minimis* air quality impact level, as shown in Table 3-2, then preconstruction ambient air quality monitoring is not required for that pollutant. In addition, if an acceptable ambient air monitoring method for the pollutant has not been established by EPA, monitoring is not required.

Preliminary Dispersion modeling was performed to determine those pollutants which could be exempted from the monitoring requirement. As verified by the revised modelling analysis described in Sections 6.0 and 7.0, the increases in air quality impacts are predicted to fall below the *de minimis* impact levels presented in Table 3-2, therefore, pre-construction monitoring is not required. The results for these pollutants are presented in Section 5.0.

Table 3-1. National and State AAQS, Allowable PSD Increments, and Significant Impact Levels

		AAQS (μg/m^3)			PSD Increments (μg/m^3)		
Pollutant	Averaging Time	Primary Standard	Secondary Standard	Florida	Class I	Class II	Significant Impact Levels (μg/m^3) [b]
Particulate Matter[c] (PM10)	Annual Arithmetic Mean	50	50	50	4	17	1
	24-Hour Maximum	150	150	150	8	30	5
Sulfur Dioxide	Annual Arithmetic Mean	80	NA	60	2	20	1
	24-Hour Maximum	365	NA	260	5	91	5
	3-Hour Maximum	NA	1,300	1,300	25	512	25
Carbon Monoxide	8-Hour Maximum	10,000	10,000	10,000	NA	NA	500
	1-Hour Maximum	40,000	40,000	40,000	NA	NA	2,000
Nitrogen Dioxide	Annual Arithmetic Mean	100	100	100	2.5	25	1
Ozone[c]	8-Hour Maximum[d]	157	157	157	NA	NA	NA
Lead	Calendar Quarter Arithmetic Mean	1.5	1.5	1.5	NA	NA	NA

Note: Particulate matter (PM10) = particulate matter with aerodynamic diameter less than or equal to 10 micrometers.
NA = Not applicable, i.e., no standard exists.

[a] Short-term maximum concentrations are not to be exceeded more than once per year.

[b] Maximum concentrations are not to be exceeded.

[c] On July 18, 1997, EPA promulgated revised AAQS for particulate matter and ozone. For particulate matter, PM2.5 standards were introduced with a 24-hour standard of 65 g/m^3 (3-year average of 98th percentile) and an annual standard of 15 g/m^3 (3-year average at community monitors). Implementation of these standards are many years away.

[d] 0.08 ppm; achieved when 3-year average of 99th percentile is 0.08 ppm or less. FDEP has not yet adopted these standards.

Sources: Federal Register, Vol. 43, No. 118, June 19, 1978.
40 CFR 50; 40 CFR 52.21.
Chapter 62-272, F.A.C.

Table 3-2. PSD Significant Emission Rates and *De Minimis* Monitoring Concentrations

Pollutant	Regulated Under	Significant Emission Rate (TPY)	*De Minimis* Monitoring Concentration[a] (μg/m3)
Sulfur Dioxide	NAAQS, NSPS	40	13, 24-hour
Particulate Matter [PM(TSP)]	NSPS	25	10, 24-hour
Particulate Matter (PM10)	NAAQS	15	10, 24-hour
Nitrogen Dioxide	NAAQS, NSPS	40	14, annual
Carbon Monoxide	NAAQS, NSPS	100	575, 8-hour
Volatile Organic Compounds (Ozone)	NAAQS, NSPS	40	100 TPY[b]
Lead	NAAQS	0.6	0.1, 3-month
Sulfuric Acid Mist	NSPS	7	NM
Total Fluorides	NSPS	3	0.25, 24-hour
Total Reduced Sulfur	NSPS	10	10, 1-hour
Reduced Sulfur Compounds	NSPS	10	10, 1-hour
Hydrogen Sulfide	NSPS	10	0.2, 1-hour
Mercury	NESHAP	0.1	0.25, 24-hour
MWC Organics	NSPS	3.5×10^{-6}	NM
MWC Metals	NSPS	15	NM
MWC Acid Gases	NSPS	40	NM
MSW Landfill Gases	NSPS	50	NM

Note: Ambient monitoring requirements for any pollutant may be exempted if the impact of the increase in emissions is below *de minimis* monitoring concentrations.

NAAQS = National ambient air quality Standards.
NM = No ambient measurement method established; therefore, no *de minimis* concentration has been established.
NSPS = New Source Performance Standards.
NESHAP = National Emission Standards for Hazardous Air Pollutants.
g/m^3 = Micrograms per cubic meter.
MWC = Municipal waste combustor.
MSW = Municipal solid waste.

[a] Short-term concentrations are not to be exceeded.
[b] No *de minimis* concentration; an increase in VOC emissions of 100 TPY or more will require monitoring analysis for ozone.
[c] Any emission rate of these pollutants.

Sources: 40 CFR 52.21.
Rule 62-212.400

4.0 BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS

4.1 INTRODUCTION

This section of the PSD application provides a detailed BACT analysis for the Hines Energy Complex Power Block 2 installation of approximately 500 MW of combined cycle (CC) generation. The CC units will consist of two CTs, two HRSGs, and one steam turbine, termed a "two-on-one" configuration.

The project's potential annual emissions of the following regulated pollutants exceed the PSD significant emission rate thresholds and are, therefore, subject to BACT review:

- Carbon Monoxide (CO)
- Nitrogen Oxides (NO_X)
- Sulfur Dioxide (SO_2)
- Particulate Matter (PM/PM_{10})
- Volatile Organic Compounds (VOC)
- Sulfuric Acid Mist (H_2SO_4)

This BACT analysis assumes that two CT units will be operating at an annual average inlet temperature of 59°F and an ambient relative humidity of 60 percent. These turbine inlet conditions represent a conservative estimate of annual average emissions, and account for the potential use of inlet cooling for the two CTs. In order to assure that conservatively high pollutant emission rates are used in the BACT analysis, the CT units are assumed to operate at 100 percent capacity, 8,760 hours per year. Natural gas will be the primary fuel and fuel oil will be the back-up fuel (an aggregate of 13,762,806 gallons per year based on 1,000 hours of operation per year between the two CTs at full load).

4.2 METHODOLOGY

This BACT analysis follows the general requirements of EPA's draft "top down" BACT guidance document (EPA, 1990c), which requires that the BACT analysis start by assuming the use of the most stringent control technology. Sources of information which were used to identify control alternatives include:

- EPA's RACT/BACT/LAER Clearinghouse (RBLC) via the RBLC Information System database;
- Recent FDEP BACT determinations for similar facilities;
- Vendor information; and
- Florida Power Corporation (FPC) experience for similar projects.

Of the control alternatives identified, the less efficient alternatives are evaluated if the most stringent control technology is determined to be technologically infeasible or unreasonable considering economic, energy, and environmental factors. The economic analyses in this section are based on the criteria listed in Table 4-1 and employ the procedures found in the Office of Air Quality Planning and Standards (OAQPS) *Control Cost Manual* (EPA, 1990b).

The final step is the selection of a BACT emission limitation corresponding to the most stringent, technically feasible control technology that was not eliminated based on energy, environmental, or economic impacts.

As indicated in Section 2.2, Table 2-3, projected annual emission rates of NO_x, CO, VOCs, PM/PM_{10}, SO_2, and H_2SO_4 mist for Power Block 2 exceed the PSD significance rates and, therefore, are subject to a BACT analysis. Control technology analyses using the top-down BACT method are contained in Section 4.4 for combustion products (PM/PM_{10}), Section 4.5 and 4.6 for products of incomplete combustion (CO and VOCs, respectively), and Sections 4.7 and 4.8 for acid gases (NO_x, and SO_2 and H_2SO_4 mist, respectively).

4.3 STATE AND FEDERAL EMISSION STANDARDS

This section provides a summary of potentially applicable emission standards at the state and federal level. The BACT emission limitations proposed for the Hines Energy Complex Power Block 2 are all more stringent than the applicable federal and state standards cited in the following summary.

FDEP emission standards for stationary sources are contained in Chapter 62-296, Stationary Sources-Emission Standards, F.A.C. This chapter contains general emission standards for sources emitting PM (Rule 62-296.320, F.A.C.) that are applicable to the Project. Visible emissions are limited to a maximum of 20 percent opacity pursuant to Rule 62-296.320(4)(b), F.A.C. Emission standards applicable to sources located in non-attainment areas are contained in Rules 62-296.500 (for ozone areas) and 62-296.700, F.A.C. (for PM non-attainment areas). Because

Power Block 2 is located in Polk County, Florida, and because this county is designated attainment for all criteria pollutants, these emission standards are not applicable. Finally, Rule 62-204.800, F.A.C., adopts federal New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAPS), respectively, by reference.

On the federal level, NSPS Subpart GG establishes emission limits for gas turbines that meet certain criteria. The Power Block 2 CTs qualify as electric utility stationary gas turbines and, therefore, are subject to the NO_x and SO_2 emission limitations of NSPS 40 CFR 60, Subpart GG, § 60.332(a)(1) and § 60.333, respectively. The proposed Hines Energy Complex Power Block 2 has no applicable NESHAP requirements.

4.4 BACT ANALYSIS FOR PM/PM_{10}

4.4.1 Potential Control Technologies

Several control technologies commonly used to limit emissions of PM include baghouses, electrostatic precipitators (ESPs), wet scrubbers and mechanical collectors. The NSPS for CT units does not establish an emission limit for particulate matter. Further, a review of RBLC documents did not reveal any post-combustion particulate matter control technologies being used on CC units. All determinations were based on the use of clean fuels and good combustion practice.

The natural gas fuel to be used in the proposed CT units will contain only trace quantities of noncombustible material. The use of low sulfur fuel oil, as a back-up fuel, will be limited. In addition, the CTs proposed for Power Block 2 will use the latest combustor technology to maximize combustion efficiency and minimize PM/PM_{10} emission rates. In fact, the manufacturer's standard operating procedures will ensure as complete combustion of the fuel as possible.

4.4.2 Proposed BACT Emission Limitations

Based on the above analysis, it is proposed that BACT for PM/PM_{10} emissions from the CTs be the use of good combustion practices and clean fuels. The CTs will be fired primarily with natural gas, with limited low sulfur fuel oil backup capability. FPC requests that the use of fuel oil be limited to no more than 13,762,806 gallons per year. This requested quantity is consistent with the current permit limit for Power Block 1 and is based on an aggregate of 1,000 hours per year of operation between the two CTs at full load and 59°F. Since the only technically feasible alternative is proposed to be BACT, an economic and environmental analysis is not required and is not presented.

Due to the difficulties associated with stack testing exhaust streams containing very low PM/PM_{10} concentrations and consistent with recent FDEP BACT determinations for CTs, a visible emissions limit of 10/20 percent opacity for natural gas/fuel oil is proposed as a surrogate BACT limit for PM/PM_{10}.

4.5 BACT ANALYSIS FOR CO

Carbon monoxide (CO) emissions result from the incomplete combustion of carbon and organic compounds. CTs have inherently low CO emissions, which are categorized as products of incomplete combustion of fossil fuels. High combustion temperatures, adequate excess air, and good fuel/air mixing during combustion will minimize CO emissions. Therefore, formation of CO is a function of the manufacturer's combustor design. Because lower combustion temperatures will result in a decrease in oxidation rates, emissions of CO will generally increase during turbine partial load conditions when combustion temperatures are lower.

4.5.1 Potential Control Technologies

A search of the RBLC was conducted for CO control determinations for natural gas fired CTs. A summary of the results is presented in Table 4-2. In addition, a summary of Florida DEP CO BACT determinations for natural gas-fired CTs is presented in Table 4-3. There are two available technologies for controlling CO from gas turbines: (1) combustion process design and good combustion practices and (2) oxidation catalysts. The projects identified through the RBLC as utilizing oxidation catalysts are located in non-attainment areas for CO.

Combustion Process Design

A combustor design based on high combustion temperatures, adequate excess air, and good fuel/air mixing during combustion will minimize CO emissions. Therefore, this control alternative is based on combustion chamber designs and operation practices that improve the oxidation process and minimize incomplete combustion. Due to the high combustion efficiency of CTs, CO emissions are inherently low.

Oxidation Catalysts

The oxidation catalyst process is based on a straight catalytic reaction requiring no additives. The reactions and catalysts used (platinum based) are similar to the catalytic oxidation technology used for automotive emission control. Products from the reaction include carbon dioxide and water. Catalytic oxidation systems are capable of CO reductions of between 50 and 80 percent. However, this reduction potential will be somewhat influenced by initial concentrations of the pollutants.

Technical Feasibility

Combustion process design is considered to be technically feasible for the proposed CTs. Oxidation catalysts are susceptible to deactivation due to impurities present in the exhaust gas stream. Arsenic, iron, sodium, phosphorous, and silica, which are present in fuel oil, will all act as catalyst contaminants causing a reduction in catalyst activity and pollutant removal efficiencies. In spite of this, the addition of an oxidation catalyst was considered to be technically feasible for this BACT analysis. Significant CO oxidation will occur at any temperature above roughly 500°F. Inlet temperature must also be maintained below 1,350 to 1,400°F to prevent thermal aging of the catalyst which will reduce catalyst activity and pollutant removal efficiencies. Exhaust gas temperatures associated with the proposed project are within this performance range. Information regarding energy, environmental, and economic impacts of an oxidation catalyst for CO are provided in the following sections.

4.5.2 Energy and Environmental Impacts

There are no significant adverse energy or environmental impacts associated with the use of good combustion designs and operating practices to minimize CO emissions.

A catalyst that oxidizes CO to CO_2 will also oxidize SO_2 to SO_3. While firing fuel oil, 50 to 60 percent of the SO_2 in the flue gas will be converted to SO_3. When the SO_3 comes in contact with moisture, it will form sulfuric acid mist (H_2SO_4) that can cause corrosion damage to downstream plant equipment and damage to surrounding vegetation. The

H_2SO_4 created will also increase particulate emissions from the facility. Because CO emission rates from CTs are inherently low, further reductions through the use of oxidation catalysts will result in minimal air quality improvements, i.e., impacts are already well below the defined PSD significant impact levels for CO. The location of the Hines Energy Complex (Polk County, Florida) is classified attainment for all criteria pollutants. Dispersion modeling of CO emissions from the Project indicate that the maximum CO impacts, without oxidation catalyst, will be many times lower than the EPA and FDEP significant impact levels; there would be no air quality benefit with the addition of an oxidation catalyst to reduce the already low CO emissions.

Although CO has been well documented as a criteria pollutant, significant international pressure is now being exerted to reduce CO_2 emission levels in response to the suspected contributions of the gas to global warming. A CO oxidation catalyst could increase the CO_2 emissions from the facility by almost 380 pounds per hour (1,660 TPY assuming 8,760 hours per year of operation).

The application of an oxidation catalyst would result in a derate of approximately 0.2 percent (0.4 MW) of CT output. Since power demand will remain constant, this derate will be replaced by a combustion source that has higher CO emissions than the planned units at the Hines Energy Complex. Further the pressure drop across the catalyst bed and resulting increase in the unit's heat rate results in a potential energy loss of 31,937 MMBtu per year per CT of natural gas. This is equivalent to the use of about 32 million cubic feet (ft^3) of additional natural gas annually.

4.5.3 Economic Impacts

An economic evaluation of an oxidation catalyst system was performed using the OAQPS factors and project-specific economic factors presented in Table 4-1. Capital and annual operating costs for the oxidation catalyst control system are summarized in Tables 4-4 and 4-5, respectively.

The capital costs for the catalytic reduction system include the costs of the catalytic reactors and balance of plant equipment. Capital costs for the catalytic emission reduction system are based on budgetary quotations from equipment manufacturers. Annual operating costs include maintenance (predominantly catalyst replacement) and lost generation due to the pressure drop across the catalyst. The total capital cost for installation of the oxidation catalyst control system is estimated to be approximately $1,343,430 per CT. The total annual cost is estimated to be approximately $576,404. The cost effectiveness (incremental emission reduction cost) of the oxidation catalyst was determined to be $2,177 per ton of CO removed. This cost-effectiveness value is conservatively low due to the 100 percent capacity factor and is in the range that has typically not been deemed BACT for CO by DEP.

4.5.4 Proposed BACT Emission Limitations

The use of oxidation catalysts to control CO emissions from CTs have been generally installed on facilities located in CO non-attainment areas. The use of combustion controls results in CO emission rates from the proposed CTs that are inherently low and in the range established as BACT for similar sources in attainment areas. As discussed in the preceding paragraphs, there are also significant energy and environmental impacts associated with the use of this technology. Further reductions through the use of oxidation catalysts will result in no measurable benefit in air quality.

Use of state-of-the-art combustion design and good operating practices to minimize incomplete combustion are proposed as BACT for CO emissions. For all CT projects recently permitted by the Florida DEP, these control techniques have been considered by FDEP to represent BACT for CO emissions. Therefore, at base load operation, the proposed BACT for CO emissions from the CTs will be 25/30 ppmvd (86/92 lb/hr at 59 °F turbine inlet conditions) for natural gas and fuel oil, respectively.

4.6 BACT for VOCs

A small amount of VOCs will be emitted by the CT as a result of incomplete combustion. The control technology established as BACT in Florida has been overwhelmingly the use of combustion controls and clean fuels. The proposed BACT emission levels for emissions are 8/11 ppmvd (16/22 lb/hr at 59 °F turbine inlet conditions) for natural gas and fuel oil, respectively. These levels are within the BACT levels recently established for other similar sources. Moreover, at these low concentrations, the application of control technologies, such as oxidation catalysts, are uncertain. The environmental benefit of further reducing the amount of VOCs from the combustion turbines proposed for Power Block 2 would be insignificant.

4.7 BACT ANALYSIS FOR NO_x

During combustion, two types of NO_X are formed: thermal NO_X and fuel NO_X. Thermal NO_X emissions are generated through the oxidation of a portion of the nitrogen contained in the combustion air. Formation of nitrogen oxides through thermal NO_X can be limited by lowering combustion temperatures by staging combustion (a reducing atmosphere followed by an oxidizing atmosphere), or by post-combustion controls. Fuel NO_x arises from the oxidation of non-elemental nitrogen contained in the fuel. The conversion of fuel-bound nitrogen (FBN) to NO_x depends on the bound nitrogen content of the fuel. In contrast to thermal NO_x, fuel NO_x formation does not vary appreciably with combustion variables such as temperature or residence time. Presently, there are no combustion process or fuel treatment technologies available to control fuel NO_x emissions. For this reason, the gas turbine NSPS (Subpart GG) contains an allowance for FBN above 0.015 percent (see Section 4.3). In the application for Power Block 2, FPC has requested a NO_x allowance for FBN levels up to 0.030 percent. NO_x emissions from combustion sources fired with fuel oil are higher than those fired with natural gas due to higher combustion temperatures and FBN contents. Natural gas may contain molecular nitrogen (N_2); however the N_2 found in natural gas does not contribute significantly to fuel NO_x formation. Typically, natural gas contains a negligible amount of FBN.

4.7.1 Potential Control Technologies

A review of the latest control technology determinations (RBLC summary in Table 4-6) indicates that the lowest NO_X emission limit established to date for a CT unit equipped with a dry low NO_x combustor is 3.5 ppmvd. This is for a natural gas-fired combined cycle (CC) unit and was based on the use of dry low NO_X combustors operating with a CT that can achieve 9 ppmvd in combination with a selective catalytic reduction (SCR) system achieving about 60% NO_x removal. The only stationary sources required to meet this most stringent control technology emission limit are those new/modified sources being located in non-attainment areas, or sources which have other unique circumstances which require exceedingly stringent pollution control. Many other projects achieve NO_x removal efficiencies between 60 and 80 percent but result in emissions limits higher than 3.5

ppmvd. Therefore, the most stringent control technology for NO_X emissions control with a CC unit using dry low NO_X combustors is an SCR system. Recent Florida DEP natural gas-fired CT NO_x BACT determinations range from 9 to 25 ppmvd at 15 percent O_2 with dry low NO_x combustors and 6 ppmvd at 15 percent O_2 with SCR. A summary of FDEP NO_x BACT determinations for natural gas-fired CTs is provided in Table 4-7.

Available technologies for controlling NO_x emissions from CTs include combustion process modifications and post-combustion exhaust gas treatment systems, as follows:

Combustion Process Modifications:

- Water/steam injection and good combustor design.
- Dry low- NO_x combustor design.

Post-Combustion Exhaust Gas Treatment Systems:

- Selective Catalytic Reduction (SCR).
- Selective Non-Catalytic Reduction (SNCR).
- SCO NO_x™

A description of each of the listed control technologies is provided in the following sections.

Water or Steam Injection and Good Combustor Design

Use of water or steam injection in the combustion zone of a CT unit can limit the amount of NO_X formed. Thermal NO_X formation is avoided due to lower combustion temperatures resulting from the water or steam injection. The degree of reduction in NO_X formation is somewhat proportional to the amount of water or steam injected into the turbine. Further, high purity water must be employed to prevent turbine corrosion and deposition of solids on the turbine blades.

Since the CT unit NSPS for NO_X was last revised, CTs have improved their tolerance to the water or steam necessary to control the NO_X emissions below the current NSPS level. However, there is still a point at which the amount of water or steam injected into the turbine seriously degrades the turbine's reliability and operational life. With the manufacturers' existing turbine designs and standard combustors, this generally occurs below a NO_X emission level of about 25 ppmvd when firing natural gas and 42 ppmvd when firing fuel oil in conventional combustion turbines. For the larger "F" class combustion turbines, wet injection has been used to achieve a level of 42 ppmvd when firing natural gas (i.e., FPL Lauderdale Repowering Project).

The advanced combustor designs available for Power Block 2 will be capable of achieving low NO_X emissions without the use of water or steam injection (dry) while firing natural gas. Considering the water use issues prevalent in Florida, dry low NO_X combustion controls are preferred. This analysis disregards further consideration of wet NO_X control CTs when natural gas is used.

Dry Low NO_x Combustor Design

CT manufacturers have committed that their future technology will support lower NO_X emissions without water injection on natural gas. Dry low NO_x combustors premix turbine fuel and air prior to combustion in the primary zone resulting in a homogeneous air/fuel mixture. For this reason, the peak and average flame temperature are the same, causing a decrease in thermal NO_x emissions in comparison to a conventional diffusion burner. The more recent designs are operated in total premix mode, but require a load transition to achieve optimal performance. Total premix mode generally occurs in the 50 to 65 percent load range. Currently, premix burners are limited in application to natural gas and loads above approximately 50 percent due to flame stability considerations. During oil-firing, water or steam injection is employed to control NO_x emissions. The Westinghouse dry low NO_X combustor design currently available is capable of combustor-controlled NO_X emissions of 35 ppmvd while burning natural gas. Fuel oil burning requires water injection and has NO_X emissions of 42 ppmvd. Fuel oil burning will be limited to no more than 13,762,806 gallons per year, based on an aggregate of 1,000 total hours per year between the two CTs at full load and is expected to have only a minor impact on water usage.

Selective Catalytic Reduction

SCR is a post-combustion method for control of NO_X emissions. The SCR process combines vaporized ammonia with NO_X in the presence of a catalyst to form nitrogen and water. The vaporized ammonia is injected into the exhaust gases prior to passage through the catalyst bed. The following primary reactions take place:

$$4NH_3 + 4NO + O_2 \Rightarrow 4N_2 + 6H_2O \qquad (1)$$

$$4NH_3 + 2NO_2 + O_2 \Rightarrow 3N_2 + 6H_2O \qquad (2)$$

The performance and effectiveness of SCR systems is directly dependent on catalyst operating temperatures. The optimum temperature range for SCR operation is 600 to 750°F. Below this temperature range, reduction reactions (1) and (2) above will not proceed, resulting in large quantities of ammonia slip. At temperatures exceeding the optimal range, oxidation of NH_3 will take place resulting in an increase in NO_x emissions. At temperatures above about 800°F, permanent damage to the catalyst occurs. NO_x removal efficiencies for SCR systems typically range from 70 to 90 percent.

Flue gas from a CT will typically range from 950°F to 1,100°F. Accordingly, an SCR device would be installed at an intermediate point of the HRSG after several rows of tubes, where a temperature of approximately 700°F occurs. The narrow SCR temperature window dictates that the SCR catalyst be precisely located in the HRSG. A recent report indicated that effective SCR operation becomes very difficult for units that see a variation in gas flow and temperature through the HRSG due to load changes or ambient temperature swings (Boericke, 1990). Another recent report indicates that maintaining the catalyst in the narrow SCR temperature window over the entire CC unit operating load range can be difficult (Shorr, 1991). Therefore, SCR performance will be difficult to maintain to very low NO_x levels if the CC unit load varies or if significant temperature swings occur.

Catalyst NO_X reduction efficiency will be affected by the NO_X concentration at the SCR inlet. The reaction mechanism requires both NO_X and ammonia to occupy a catalytic reaction site at the same time. This is a random event. The lower the NO_X concentration, the less likely it is that any one ammonia gas molecule and NO_X gas molecule will meet on a reaction site. Therefore, as the SCR inlet concentration of NO_X decreases, the catalyst needs to become larger and/or the amount of ammonia added needs to be increased (leading to increased ammonia slip) for similar NO_X reduction efficiencies. The dry low NO_X combustors have relatively low NO_X emissions and will therefore require a greater volume of catalyst than a standard combustor would for the same NO_X removal efficiency.

Catalyst NO_X reduction efficiency also will be affected by the type of fuel being burned. When firing fuel oil, the SCR catalyst will oxidize approximately three percent of the SO_2 in the flue gas to SO_3. Catalytic reduction efficiency is therefore reduced when available reaction sites are occupied by sulfur compounds. Additionally, the ammonia present in the flue gas will react with the SO_3 to form ammonia sulfate salts and the water in the flue gas will react with the SO_3 to form sulfuric acid mist. The formation of ammonia sulfate salts will reduce the amount of ammonia available for reaction with the NO_X. Ammonium bisulfate, one of the ammonia salts formed, will also reduce a CC unit's thermal efficiency by coating the heat transfer surfaces of the HRSG and potentially limit unit availability due to forced outages for HRSG cleanup. Both the ammonia sulfate salts and the sulfuric acid mist will increase the amount of particulate matter emitted in the flue gas to a level of approximately 16 lbs/hr per CT in the form of ammonium bisulfate (38 percent increase). This particulate will predominately consist of matter less than 10 microns in size (PM_{10}).

Catalyst life expectancy also can be affected by the type of fuel burned. Catalyst poisoning can be caused by such trace elements as arsenic, beryllium, cadmium, chromium, copper, lead, manganese, mercury, and nickel, all of which can be found in fuel oil. Arsenic, the major poison, can be deposited on catalyst surfaces in the form of gaseous arsenic oxide, which can clog the small pores of the catalyst and prevent the ammonia/nitrogen oxide mixture from being catalytically oxidized. Due to the potential for chemical contamination with fuels other than natural gas, application of SCR to CTs has been primarily limited to natural gas-fired units.

Selective Non-Catalytic Reduction

Nitrogen oxide emissions from other types of combustion sources also have been controlled through installation of selective noncatalytic reduction (SNCR) systems such as Thermal $DeNO_X$ and NO_XOUT. Chemical reactions for the Thermal $DeNO_x$ process are as follows:

$$4NO + 4NH_3 + 0_2 \Rightarrow 4N_2 + 6\ H_20 \quad (3)$$
$$4\ NH_3 + 5\ 0_2 \Rightarrow 4NO + 6\ H_20 \quad (4)$$

The NO_xOUT process is similar with the exception that urea is used in place of NH_3. The critical design parameter for both SNCR processes is the reaction temperature. At temperatures below 1,600°F, rates for both reactions decrease allowing unreacted NH_3 to exit with the exhaust stream. Temperatures between 1,600 and 2,000°F will favor Reaction (3), resulting in a reduction in NO_x emissions. Reaction (4) will dominate at temperatures above approximately 2,000°F causing an increase in NO_x emissions. Temperatures below 1,300°F result in ammonia slipping through the system unreacted without any corresponding reduction in NO_X emissions. As reported earlier, the temperature at the outlet of a CT unit utilizing dry low NO_X combustors, is too low (950°F to 1,100°F) for such a system. Accordingly, this alternative is judged not to be technically feasible for application on a CC unit.

SCONO$_x$™

SCONO$_x$™ is a NO_x and CO control system exclusively offered by Goal Line Environmental Technologies (GLET). GLET is a partnership formed by Sunlaw Energy Corporation and Advanced Catalyst Systems, Inc.

The SCONO$_x$™ system employs a single catalyst to simultaneously oxidize CO to CO_2 and NO to NO_2. NO_2 formed by the oxidation of NO is subsequently absorbed onto the catalyst surface through the use of a potassium carbonate absorber coating. The SCONO$_x$™ oxidation/absorption cycle reactions are:

$$CO + 1/2\ O_2 \Rightarrow CO_2 \qquad (5)$$

$$NO + 1/2\ O_2 \Rightarrow NO_2 \qquad (6)$$

$$2NO_2 + K_2CO_3 \Rightarrow CO_2 + KNO_2 + KNO_3 \qquad (7)$$

CO_2 produced by reaction (5) and (6) is released to the atmosphere as part of the CT/HRSG exhaust gas stream.

As shown in Reaction (7), the potassium carbonate catalyst coating reacts with NO_2 to form potassium nitrites and nitrates. Prior to saturation of the potassium carbonate coating, the catalyst must be regenerated. This regeneration is accomplished by passing a dilute hydrogen-reducing gas across the surface of the catalyst in the absence of O_2. Hydrogen in the reducing gas reacts with the nitrites and nitrates to form water and elemental nitrogen. CO_2 in the regeneration gas reacts with potassium nitrites and nitrates to form potassium carbonate; this compound is the catalyst absorber coating present on the surface of the catalyst at the start of the oxidation/absorption cycle. The SCONO$_x$™ regeneration cycle reaction is:

$$KNO_2 + KNO_3 + 4\ H_2 + CO_2 \Rightarrow K_2CO_3 + 4\ H_2O_{(g)}) + N_2 \qquad (8)$$

Water vapor and elemental nitrogen are released to the atmosphere as part of the CT/HRSG exhaust stream. Following regeneration, the SCONO$_x$™ catalyst has a fresh coating of potassium carbonate, allowing the oxidation/absorption cycle to begin again. There is no net gain or loss of potassium carbonate after both the oxidation/absorption and regeneration cycles have been completed.

Since the regeneration cycle must take place in an oxygen-free environment, the section of catalyst undergoing regeneration is isolated from the exhaust gas stream using a set of louvers. Each catalyst section is equipped with a set of upstream and downstream louvers. During the regeneration cycle, these louvers close and valves open allowing fresh regeneration gas to enter and spent regeneration gas to exit the catalyst section being regenerated. At any given time, 75 percent of the catalyst sections will be in the oxidation/absorption cycle, while 25 percent will be in regeneration mode. A regeneration cycle is typically set to last for 3 to 5 minutes.

Regeneration gas is produced by reacting natural gas with O_2 present in ambient air. The SCONO$_x$™ system uses a gas generator produced by Surface Combustion. This unit uses a two-stage process to produce hydrogen and carbon dioxide. In the first stage, natural gas and ambient air are reacted across a partial oxidation catalyst at 1,900°F to form CO and hydrogen. Steam is added and the gas mixture is then passed across a low temperature shift catalyst, forming CO_2 and additional hydrogen. The resulting gas stream is diluted to less than 4 percent hydrogen using steam or another inert gas. The regeneration gas reactions are:

$$CH_4 + 1/2\ O_2 + 1.88\ N_2 \Rightarrow CO + 2\ H_2 + 1.88\ N_2 \qquad (9)$$

$$CO + 2\ H_2 + H_2O + 1.88\ N2_2 \Rightarrow CO_2 + 3\ H_2 + 1.88\ N_2 \qquad (10)$$

The SCONO$_x$™ operates at a temperature range of 300 to 700°F and, therefore, must be installed in the appropriate temperature section of a HRSG. For SCONO$_x$™ systems installed in locations of the HRSG above 500°F, a separate regeneration gas generator is not required. Instead, regeneration gas is produced by introducing natural gas directly across the SCONO$_x$™ catalyst that reforms the natural gas.

The SCONO$_x$™ system catalyst is subject to reduced performance and deactivation due to exposure to sulfur oxides. For this reason, an additional catalytic oxidation/absorption system (SCONO$_x$™) to remove sulfur compounds is installed upstream of the SCONO$_x$™ catalyst. During regeneration of the SCONO$_x$™ catalyst, either hydrogen sulfide or SO_2 is released to the atmosphere as part of the CT/HRSG exhaust gas stream. The absorption portion of the SCONO$_x$™ process is proprietary. SCONO$_x$™ oxidation/absorption and regeneration reactions are:

$$CO + 1/2\ O_2 \Rightarrow CO_2 \qquad (11)$$

$$SO_2 + 1/2\ O_2 \Rightarrow SO_3 \qquad (12)$$

$$SO_3 + SORBER \Rightarrow [SO_3 + SORBER] \qquad (13)$$

$$[SO_3 + SORBER] + 4\ H_2 \Rightarrow H_2S + 3\ H_2O \qquad (14)$$

Utility materials needed for the operation of the SCONO$_x$™ control system include ambient air, natural gas, water, steam, and electricity. The primary utility material is natural gas used for regeneration gas production. Steam is used as the carrier/dilution gas for the regeneration gas. Electricity is required to operate the computer control system, control valves, and louver actuators.

Commercial experience to date with the $SCONO_x$™ control system is limited to one small combined cycle (CC) power plant located in Los Angeles. This power plant, owned by GLET partner Sunlaw Energy Corporation, utilizes a GE LM2500 turbine equipped with water injection to control NO_x emissions to approximately 25 ppmvd. The $SCONO_x$™ control system was installed at the Sunlaw Energy facility in December 1996 and has achieved a NO_x exhaust concentration of 3.5 ppmv resulting in an approximate 85 percent NO_x removal efficiency.

Technical Feasibility

All of the combustion process control technologies presented above (water/steam injection and good combustor design and dry low NO_x combustor design) would be potentially feasible for the Power Block 2 CTs. Of the post-combustion stack gas treatment technologies, SNCR is not feasible because the temperature required for this technology (between 1,600 and 2,000°F) exceeds that found in CT exhaust gas streams (approximately 1,000°F). The $SCONO_x$™ control technology is not considered to be technically feasible because it has not been commercially demonstrated on large CTs. The CTs planned for the Hines Energy Complex Power Block 2, Westinghouse 501 F units, each have a nominal generating capacity of 165 MW which are approximately six times larger than the nominal 25-MW GE LM2500 utilized at the Sunlaw Energy Corporation Los Angeles facility. Technical problems associated with scale-up of the $SCONO_x$™ technology given the large differences in machine flow rates are unknown. Additional concerns with the $SCONO_x$™ control technology include process complexity (multiple catalytic oxidation / absorption / regeneration systems), reliance on only one supplier, and the relatively brief (approximately 18 months) operating history of the technology.

The BACT analysis for NO_x for the Power Block 2 CTs evaluated the use of dry low NO_x combustors available from Westinghouse and the application of post-combustion SCR control technologies. The dry low NO_x combustors are expected to achieve 35 ppmvd corrected to 15 percent oxygen when firing natural gas and with water injection achieve 42 ppmvd corrected to 15 percent oxygen when firing distillate oil. Steam/water injection technology for natural gas firing was not evaluated because it results in NO_x emissions that are comparable to those achieved by dry low NO_x combustor technology and has associated water use and lower heat rate considerations. The water consumption and sludge treatment/disposal requirements associated with water/steam injection do not exist for dry low-NO_x combustors, making dry low NO_x combustor technology preferable to wet injection as the primary control for natural gas firing. The SCR system was evaluated based on achieving a NO_x concentration of 6 ppmvd corrected to 15 percent oxygen when firing only natural gas. This represents a control efficiency of about 83 percent which is at the upper ranges of removal efficiencies established as BACT with SCR. Information regarding energy, environmental, and economic impacts and proposed BACT limits for NO_x are provided in the following sections.

4.7.2 Energy and Environmental Impacts

The use of advanced dry low NO_x combustor technology will not have a significant adverse impact on CT heat rate.

The installation of SCR technology would cause an increase in back pressure on the CTs due to the pressure drop across the catalyst bed. The back pressure would also increase with the installation of additional catalyst volume. Higher NOx removal would require additional catalyst volume resulting in greater energy penalty. The energy penalty would be approximately 0.5 percent for SCR installed on Power Block 2. Additional energy would be needed for the pumping of aqueous NH_3 from storage to the injection nozzles and generation of steam for NH_3 vaporization. Energy penalty due to CT back pressure is projected to be 7,971,600 kwh per year for each CT while reducing NOx to 6 ppmvd corrected to 15 percent oxygen. The total SCR energy penalty including dilution air fans is estimated to be 8,672,400 kwh per year for each CT which is equivalent to an energy loss of 83,992 MMBtu/yr. This is equivalent to the use of about 84 million ft^3 of natural gas annually based on a gas heating value of 1,000 Btu per ft^3.

There are no significant adverse environmental effects due to the use of advanced dry low NO_x combustor technology. Application of SCR technology would result in the following environmental impacts:

- NH_3 emissions due to *ammonia slip*; NH_3 emissions are estimated to total 124 tpy (at base load and 59°F ambient temperature) for a typical SCR design and ammonia slippage rate of 10 ppmvd for each CT. Ammonia slip is much lower during the early stages of catalyst usage and increases with age. Increasing efficiency, such as reducing the already low exhaust NOx emissions of 6 ppm to a lower level can also potentially increase ammonia slip. This is especially true because the SCR design is already at the upper range of its maximum reduction efficiency.
- Ammonium bisulfate and ammonium sulfate particulate emissions due to the reaction of NH_3 with SO_3 present in the exhaust gases; as a result, total particulate matter emissions would increase. This effect is more of a concern

when firing oil since the PM emission rate would increase by about 38 percent during oil firing. While the NO_x reduction using SCR with oil is about 27 tons/year/CT, an additional 4 tons/year of particulate would result directly from operation of the SCR during oil firing.

- A human health risk due to potential leaks from the storage of large quantities of NH_3. The use of aqueous ammonia, although still regulated under EPA's regulations implementing Section 112r of the Clean Air Act, is less hazardous than anhydrous ammonia.

4.7.3 Economic Impacts

An assessment of economic impacts was performed by comparing control costs between a baseline case of advanced dry low NO_x combustor technology and baseline technology with the addition of SCR controls. Dry low-NO_x technology provided by Westinghouse is expected to achieve a NO_x exhaust concentration of 35 ppmvd at 15 percent O_2. SCR technology was premised to achieve NO_x concentrations of 6 ppmvd at 15 percent O_2 for natural gas-firing. The NO_x concentration of 6 ppmvd is representative of the maximum NO_x removal efficiencies determined as BACT for natural gas-fired CTs equipped with dry low NO_x combustor technology and SCR controls. As supplied by Westinghouse, the 501 F unit is equipped with dry low NO_x combustors. Westinghouse does not offer any other option with respect to combustor type or design.

The cost impact analysis was conducted using the OAQPS factors previously summarized in Table 4-1 and the project-specific factors discussed above. Emission reductions were calculated assuming base load operation for 8,760 hr/yr at an annual average ambient temperature of 59°F. Specific capital and annual operating costs for the SCR control system are summarized in Tables 4-8 and 4-9, respectively.

Cost effectiveness for the application of SCR technology to the Hines Energy Complex Power Block 2 for natural gas firing was determined to be $2,694 per ton of NO_x removed. This control cost is for an SCR system achieving NO_x levels of 6 ppmvd at 15 percent oxygen while firing natural gas with an initial NO_x level of 35 ppmvd using dry low NO_x combustor technology available from Westinghouse. Achieving NO_x levels of 6 ppmvd at 15 percent oxygen while firing natural gas results in a NO_x reduction of 883 tons/year (at 100 percent load).

Achieving NO_x levels of 15 ppmvd at 15 percent oxygen while firing oil results in only a NO_x reduction of 27.3 tons/year/CT (at 100 percent load). However, an additional 4 tons/year/CT of fine PM will be generated from the use of oil. The increase in PM emissions represents about a 40 percent increase in PM emissions over that proposed. Moreover, the PM emissions result from the gaseous reaction of SO_3 and ammonia forming ammonium salts compounds such as ammonium sulfate and bisulfate. These compounds are acidic and can be deposited within the catalyst and HRSG surfaces or emitted as fine particulate matter. Given the backup nature of fuel oil and the potential technical and environmental consequences of using an SCR during fuel oil firing, an emissions limit of 42 ppmvd using wet injection is proposed as BACT.

4.7.4 Proposed BACT Emission Limitations

NO_x BACT emission limits proposed for the Hines Energy Complex Power Block 2 CTs, are based on the application of dry low NO_x combustors achieving NOx levels to 35 ppmvd and a gas-only SCR system achieving 45 lb/hour, 24-hour block average, based on 6 ppmvd. The emission level proposed is equivalent to 0.17 lb/MW which is over 9 times lower than the recently promulgated EPA new source performance standards (NSPS) for steam electric units. This new NSPS has a NOx limit for new sources of 1.6 lb/MW (September 16, 1998; 63FR179).

Reducing NO_x levels while firing oil also has marginal benefits. The use of oil is for back up purposes and will not exceed a total of 13,762,806 gallons per year, based on an aggregate of 1,000 hours per year of operation between the 2 CTs at full load. The use of SCR while firing oil will also increase fine PM emissions by about 16 lb/hr. This is about a 40 percent increase in the PM emission rate when firing oil and an upward adjustment in the proposed emission rate (42.6 lb/hr at 59 °F turbine inlet) would be required. The proposed emission rate using wet injection is equivalent to 1.2 lb/MW (net) which is 25 percent lower than the recently promulgated NSPS. Moreover, this emission rate is only for the backup fuel. Therefore, FPC does not propose to utilize the SCR system during oil firing.

4.8 BACT ANALYSIS FOR SO_2 AND H_2SO_4 MIST

4.8.1 Potential Control Technologies

The NSPS established by EPA for emissions from CTs sets a maximum SO_2 level in the flue gas of 150 ppmvd or a maximum fuel sulfur content of 0.8 percent by weight (40 CFR 60, Subpart GG). Technologies employed to control SO_2 and H_2SO_4 mist emissions from combustion sources consist of fuel treatment and post-combustion add-on controls; i.e., flue gas desulfurization (FGD) systems.

Fuel Treatment

Fuel treatment technologies are applied to gaseous, liquid, and solid fuels to reduce their sulfur contents prior to delivery to end fuel users. For wellhead natural gas containing sulfur compounds (e.g., hydrogen sulfide) and for crude oil, a variety of technologies are used by fuel suppliers to remove these sulfur compounds prior to delivery to customers.

Flue Gas Desulfurization

FGD systems remove SO_2 from exhaust streams by utilizing an alkaline reagent to form sulfite and sulfate salts. The reaction of SO_2 with the alkaline chemical can be performed using either a wet- or dry-contact system. FGD wet scrubbers typically employ sodium, calcium, or dual-alkali reagents using packed or spray towers. Wet FGD systems will generate wastewater and wet sludge streams requiring treatment and disposal. In a dry FGD system, an alkaline slurry is injected into the combustion process exhaust stream. The liquid sulfite/sulfate salts that form from the reaction of the alkaline slurry with SO_2 are dried by heat contained in the exhaust stream and subsequently removed by downstream PM control equipment

Technical Feasibility

Current RBLC documents do not list any natural gas- or fuel oil-fired CC units that are required to use flue gas desulfurization (FGD) systems to meet SO_2 or H_2SO_4 emission requirements. The maximum emissions rates for Power Block 2 using pipeline natural gas and distillate fuel are equivalent to 0.0033 and 0.057 lb/MMBtu, respectively. These levels are clearly within the ranges established as BACT for other projects.

The high pressure drops across FGD systems make them technically infeasible for application on CC units. Also, addition of an FGD system would be an inappropriate method of SO_2 or H_2SO_4 control, because emissions of these pollutants will be low. The significant capital and operating costs associated with FGD would make the project economically infeasible.

4.8.2 Proposed BACT Emission Limitations

Because post-combustion SO_2 and H_2SO_4 mist controls are not applicable, use of low sulfur fuel is considered to represent BACT for the Hines Energy Complex Power Block 2 CTs. Natural gas utilized at the Project will contain no more than 1.0 grain of sulfur per 100 scf and the distillate fuel oil will contain no more than 0.05 percent sulfur, by weight. Based on economic, energy, and environmental considerations, firing natural gas as the primary fuel and limiting the amount of time low sulfur fuel oil operation will be allowed (i.e., a total of 13,762,806 gallons per year, based on an aggregate of 1,000 hours per year of operation at full load) is proposed as BACT for SO_2 and H_2SO_4 emissions.

4.9 SUMMARY OF PROPOSED BACT EMISSION LIMITS

Emission rates and methods of compliance proposed as BACT for each pollutant subject to review are summarized in Table 4-10.

Table 4-1. Capital and Annual Operating Cost Factors

Cost Item	Factor
Direct Capital Costs	
Sales tax	0.06 x purchased equipment cost
Freight	0.05 x purchased equipment cost
Foundations and supports	0.08 x purchased equipment cost
Handling and erection	0.14 x purchased equipment cost
Electrical	0.04 x purchased equipment cost
Piping	0.02 x purchased equipment cost
Insulation	0.01 x purchased equipment cost
Painting	0.01 x purchased equipment cost
Indirect Capital Costs	
Engineering	0.10 x purchased equipment cost
Construction and field expenses	0.05 x purchased equipment cost
Contractor fees	0.10 x purchased equipment cost
Start-up	0.02 x purchased equipment cost
Performance testing	0.01 x purchased equipment cost
Contingencies	0.10 x purchased equipment cost
Direct Annual Operating Costs	
Supervisor labor	0.15 x total operator labor cost
Indirect Annual Operating Costs	
Overhead	0.60 x total of operating, supervisory, labor and maintenance materials.
Property taxes	0.01 x total capital investment
Insurance	0.01 x total capital investment

Source: EPA, 1990b.

Table 4-2. RBLC CO Summary – Natural Gas-Fired Combustion Turbines

RBLC ID	Facility Name	City	Permit Dates: Issuance	Permit Dates: Last Update	Process Description	Thruput Rate	Emission Limit	Control System Description
AL-0069	INTERNATIONAL PAPER CO. RIVERDALE MILL	SELMA	1/11/93	3/24/95	TURBINE, STATIONARY (GAS-FIRED) WITH DUCT BURNER	40 MW	22.1 LB/HR	DESIGN
AL-0074	FLORIDA GAS TRANSMISSION COMPANY	MOBILE	8/5/93	5/12/94	TURBINE, NATURAL GAS	12,600 BHP	0.42 GM/HP HR	AIR-TO-FUEL RATIO CONTROL, DRY COMBUSTION CONTROLS
AL-0096	MEAD COATED BOARD, INC.	PHENIX CITY	3/12/97	5/31/97	COMBINED CYCLE TURBINE (25 MW)	568 MMBTU/HR	28 PPMVD@15% O2 (GAS)	PROPER DESIGN AND GOOD COMBUSTION PRACTICES
CA-0613	UNOCAL	WILMINGTON	7/18/89	12/5/94	TURBINE, GAS (SEE NOTES)		10 PPM @ 15% O2	OXIDATION CATALYST
FL-0068	ORANGE COGENERATION LP	BARTOW	12/30/93	1/13/95	TURBINE, NATURAL GAS, 2	368 MMBTU/H	30 PPMVD	GOOD COMBUSTION
FL-0072	TIGER BAY LP	FT. MEADE	5/17/93	1/13/95	TURBINE, GAS	1,615 MMBTU/H	49 LB/H	GOOD COMBUSTION PRACTICES
FL-0078	KISSIMMEE UTILITY AUTHORITY	INTERCESSION CITY	4/7/93	1/13/95	TURBINE, NATURAL GAS	869 MMBTU/H	54 LB/H	GOOD COMBUSTION PRACTICES
FL-0078	KISSIMMEE UTILITY AUTHORITY	INTERCESSION CITY	4/7/93	1/13/95	TURBINE, NATURAL GAS	367 MMBTU/H	40 LB/H	GOOD COMBUSTION PRACTICES
FL-0080	AUBURNDALE POWER PARTNERS, LP	AUBURNDALE	12/14/92	1/13/95	TURBINE, GAS	1,214 MMBTU/H	15 PPMVD	GOOD COMBUSTION PRACTICES
FL-0082	FLORIDA POWER CORPORATION POLK COUNTY SITE	BARTOW	2/25/94	1/13/95	TURBINE, NATURAL GAS (2)	1,510 MMBTU/H	25 PPMVD	GOOD COMBUSTION PRACTICES
FL-0102	PANDA-KATHLEEN, L.P.	LAKELAND	6/1/95	5/20/96	COMBINED CYCLE COMBUSTION TURBINE (TOTAL 115MW)	75 MW	25 PPM @ 15% O2	COMBUSTION CONTROLS
FL-0109	KEY WEST CITY ELECTRIC SYSTEM	KEY WEST	8/28/95	5/31/96	TURBINE, EXISTING CT RELOCATION TO A NEW PLANT	23 MW	20 PPM @ 15% O2 FULL LD	GOOD COMBUSTION
GA-0053	HARTWELL ENERGY LIMITED PARTNERSHIP	HARTWELL	7/28/92	3/24/95	TURBINE, GAS FIRED (2 EACH)	1,817 M BTU/HR	25 PPMVD @ FULL LOAD	FUEL SPEC: CLEAN BURNING FUELS
GA-0063	MID-GEORGIA COGEN.	KATHLEEN	4/3/96	8/19/96	COMBUSTION TURBINE (2), NATURAL GAS	116 MW	10 PPMVD	COMPLETE COMBUSTION
IN-0071	PORTSIDE ENERGY CORP.	PORTAGE	5/13/96	5/31/97	TURBINE, NATURAL GAS-FIRED	63 MEGAWATT	12 LBS/HR	GOOD COMBUSTION AND EMISSIONS NOT TO EXCEED 10 PPMVD
IN-0071	PORTSIDE ENERGY CORP.	PORTAGE	5/13/96	5/31/97	TURBINE, NATURAL GAS-FIRED	63 MEGAWATT	40 LBS/HR	GOOD COMBUSTION AND EMISSIONS NOT TO EXCEED 40 PPMVD
KY-0053	KENTUCKY UTILITIES COMPANY	MERCER	3/10/92	3/24/95	TURBINE, #2 FUEL OIL/NATURAL GAS (8)	1,500 MM BTU/HR (EAC	75 LB/HR (EACH)	COMBUSTION CONTROL
LA-0086	INTERNATIONAL PAPER	MANSFIELD	2/24/94	4/17/95	TURBINE/HRSG, GAS COGEN	338 MM BTU/HR TURB	165.9 LB/HR	COMBUSTION CONTROL
LA-0089	FORMOSA PLASTICS CORPORATION, LOUISIANA	BATON ROUGE	3/2/95	4/17/95	TURBINE/HRSG, GAS COGENERATION	450 MM BTU/HR	25.8 LB/HR	PROPER OPERATION
LA-0091	GEORGIA GULF CORPORATION	PLAQUEMINE	3/26/96	4/21/97	GENERATOR, NATURAL GAS FIRED TURBINE	1,123 MM BTU/HR	872.4 TPY CAP FOR 3 TURB.	GOOD COMBUSTION PRACTICE AND PROPER OPERATION
LA-0093	FORMOSA PLASTICS CORPORATION, BATON ROUGE PLANT	BATON ROUGE	3/7/97	4/28/97	TURBINE/HSRG, GAS COGENERATION	450 MM BTU/HR	70 LB/HR	COMBUSTION DESIGN AND CONSTRUCTION.
LA-0096	UNION CARBIDE CORPORATION	HAHNVILLE	9/22/95	5/31/97	GENERATOR, GAS TURBINE	1,313 MM BTU/HR	198.6 LB/HR	NO ADD-ON CONTROL GOOD COMBUSTION PRACTICE
MA-0015	PEABODY MUNICIPAL LIGHT PLANT	PEABODY	11/30/89	3/24/95	TURBINE, 38 MW NATURAL FAS FIRED	412 MMBTU/HR	40 PPM @ 15% O2	GOOD COMBUSTION PRACTICES
MD-0018	BALTIMORE GAS & ELECTRIC - PERRYMAN PLANT	PERRYMMAN		3/24/95	TURBINE, 140 MW NATURAL GAS FIRED ELECTRIC	140 MW	20 PPM @ 15% O2	GOOD COMBUSTION PRACTICES
NC-0055	DUKE POWER CO. LINCOLN COMBUSTION TURBINE STATION	LOWESVILLE	12/20/91	3/24/95	TURBINE, COMBUSTION	1,247 MM BTU/HR	60 LB/HR	COMBUSTION CONTROL
NC-0055	DUKE POWER CO. LINCOLN COMBUSTION TURBINE STATION	LOWESVILLE	12/20/91	3/24/95	TURBINE, COMBUSTION	1,313 MM BTU/HR	59 LB/HR	COMBUSTION CONTROL
NJ-0009	NEWARK BAY COGENERATION PARTNERSHIP	NEWARK	11/1/90	7/7/93	TURBINE, NATURAL GAS FIRED	585 MMBTU/HR	0.0055 LB/MMBTU	CATALYTIC OXIDATION
NJ-0013	LAKEWOOD COGENERATION, L.P.	LAKEWOOD TOWNSHIP	4/1/91	5/29/95	TURBINES (NATURAL GAS) (2)	1,190 MMBTU/HR (EACH	0.026 LB/MMBTU	TURBINE DESIGN
NJ-0017	NEWARK BAY COGENERATION PARTNERSHIP, L.P.	NEWARK	6/9/93	5/29/95	TURBINES, COMBUSTION, NATURAL GAS-FIRED (2)	617 MMBTU/HR (EACH	1.8 PPMDV	OXIDATION CATALYST
NM-0021	WILLIAMS FIELD SERVICES CO. - EL CEDRO COMPRESSOR	BLANCO	10/29/93	3/2/94	TURBINE, GAS-FIRED	11,257 HP	50 PPM @ 15% O2	COMBUSTION CONTROL
NM-0022	MARATHON OIL CO. - INDIAN BASIN N.G. PLAN	CARLSBAD	1/11/95	4/26/95	TURBINES, NATURAL GAS (2)	5,500 HP	13.2 LBS/HR	LEAN-PREMIXED COMBUSTION TECHNOLOGY.
NM-0024	MILAGRO, WILLIAMS FIELD SERVICE	BLOOMFIELD		5/29/95	TURBINE/COGEN, NATURAL GAS (2)	900 MMCF/DAY	27.6 PPM @ 15% O2	
NM-0029	SOUTHWESTERN PUBLIC SERVICE COMPANY/CUNNINGHAM STA	HOBBS	2/15/97	3/31/97	COMBUSTION TURBINE, NATURAL GAS	100 MW	SEE FACILITY NOTES	GOOD COMBUSTION PRACTICES
NM-0031	LORDSBURG L.P.	LORDSBURG	6/18/97	9/29/97	TURBINE, NATURAL GAS-FIRED, ELEC. GEN.	100 MW	27 LBS/HR	DRY LOW-NOX TECHNOLOGY BY MAINTAINING PROPER AIR-FUEL
NV-0017	NEVADA POWER COMPANY, HARRY ALLEN PEAKING PLANT	LAS VEGAS	9/18/92	3/24/95	COMBUSTION TURBINE ELECTRIC POWER GENERATION	600 MW (8 UNITS 75	152.5 TPY (EACH TURBINE)	PRECISION CONTROL FOR THE LOW NOX COMBUSTOR
NV-0018	NEVADA COGENERATION ASSOCIATES #2	LAS VEGAS	1/17/91	3/24/95	COMBINED-CYCLE POWER GENERATION	85 MW POWER OUTP	39.96 LBS/HR	CATALYTIC CONVERTER
NY-0044	BROOKLYN NAVY YARD COGENERATION PARTNERS L.P.	NEW YORK CITY	6/6/95	6/30/95	TURBINE, NATURAL GAS FIRED	240 MW	4 PPM @ 15% O2	
NY-0045	SELKIRK COGENERATION PARTNERS, L.P.	SELKIRK	6/18/92	8/13/94	COMBUSTION TURBINES (2) (252 MW)	1,173 MMBTU/HR (EACH	10 PPM	COMBUSTION CONTROLS
NY-0045	SELKIRK COGENERATION PARTNERS, L.P.	SELKIRK	6/18/92	9/13/94	COMBUSTION TURBINE (79 MW)	1,173 MMBTU/HR	25 PPM	COMBUSTION CONTROL
NY-0046	SARANAC ENERGY COMPANY	PLATTSBURGH	7/31/92	9/13/94	TURBINES, COMBUSTION (2) (NATURAL GAS)	1,123 MMBTU/HR (EACH	3 PPM	OXIDATION CATALYST
NY-0047	PASNY/HOLTSVILLE COMBINED CYCLE PLANT	HOLTSVILLE	8/1/92	8/13/94	TURBINE, COMBUSTION GAS (150 MW)	1,146 MMBTU/HR (GAS)	8.5 PPM	COMBUSTION CONTROL
NY-0049	KAMINE/BESICORP BEAVER FALLS COGENERATION FACILITY	BEAVER FALLS	11/9/92	9/13/94	TURBINE, COMBUSTION (NAT. GAS & OIL FUEL) (79MW)	650 MMBTU/HR	9.5 PPM	COMBUSTION CONTROLS
NY-0050	SITHE/INDEPENDENCE POWER PARTNERS	OSWEGO	11/24/92	9/13/94	TURBINES, COMBUSTION (4) (NATURAL GAS) (1012 MW)	2,133 MMBTU/HR (EACH	13 PPM	COMBUSTION CONTROLS
NY-0080	PROJECT ORANGE ASSOCIATES	SYRACUSE	12/1/93	3/31/95	GE LM-5000 GAS TURBINE	550 MMBTU/HR	62 LB/HR TEMP > 20F	NO CONTROLS
NY-0080	PROJECT ORANGE ASSOCIATES	SYRACUSE	12/1/93	3/31/95	STACK (TURBINE AND DUCT BURNER)	715 MMBTU/HR	106.4 LB/HR TEMP > 20F	OXIDATION CATALYST
OH-0216	CNG TRANSMISSION	WASHINGTON COURT HOUSE	8/12/92	4/5/95	TURBINE (NATURAL GAS) (3)	5,500 HP (EACH)	0.015 G/HP-HR	FUEL SPEC: USE OF NATURAL GAS
OR-0010	PORTLAND GENERAL ELECTRIC CO.	BOARDMAN	5/31/94	8/6/97	TURBINES, NATURAL GAS (2)	1,720 MMBTU	15 PPM @ 15% O2	GOOD COMBUSTION PRACTICES
OR-0011	HERMISTON GENERATING CO.	HERMISTON	4/1/94	6/1/95	TURBINES, NATURAL GAS (2)	1,696 MMBTU	15 PPM @ 15% O2	GOOD COMBUSTION PRACTICES
PA-0098	GRAYS FERRY CO. GENERATION PARTNERSHIP	PHILADELPHIA	11/4/92	7/20/94	TURBINE (NATURAL GAS & OIL)	1,150 MMBTU	0.0055 LB/MMBTU (GAS)*	COMBUSTION
PA-0148	BLUE MOUNTAIN POWER, LP	RICHLAND	7/31/96	8/23/96	COMBUSTION TURBINE WITH HEAT RECOVERY BOILER	153 MW	3.1 PPM @ 15% O2	OXIDATION CATALYST. AT 75% NG LIMIT SET TO 22.1 PPM
PA-0149	BUCKNELL UNIVERSITY	LEWISBURG	11/26/97	11/30/97	NG FIRED TURBINE, SOLAR TAURUS T-7300S	5 MW	50 PPMV@15%O2	GOOD COMBUSTION
PR-0004	ECOELECTRICA, L.P.	PENUELAS	10/1/96	5/6/98	TURBINES, COMBINED-CYCLE COGENERATION	461 MW	33 PPMDV	COMBUSTION CONTROLS
TX-0231	WEST CAMPUS COGENERATION COMPANY	COLLEGE STATION	5/2/94	10/31/94	GAS TURBINES	75 MW (TOTAL POW	300 TPY	INTERNAL COMBUSTION CONTROLS
VA-0189	GORDONSVILLE ENERGY L.P.	FAIRFAX	9/25/92	3/24/95	TURBINES (2) (EACH WITH A SF)	2 X10(9) BTU/HR N	57 LBS/HR/UNIT	GOOD COMBUSTION PRACTICES
VA-0199	GORDONSVILLE ENERGY L.P.	FAIRFAX	9/25/92	3/24/95	TURBINE FACILITY, GAS	1,331 X10(7) SCF/Y NAT	249.9 TOTAL TPY	GOOD COMBUSTION PRACTICES
VA-0190	BEAR ISLAND PAPER COMPANY, L.P.	ASHLAND	10/30/92	5/7/97	TURBINE, COMBUSTION GAS	474 X10(6) BTU/HR N	11 LBS/HR	GOOD COMBUSTION
VA-0190	BEAR ISLAND PAPER COMPANY, L.P.	ASHLAND	10/30/92	5/7/97	TURBINE, COMBUSTION GAS (TOTAL)		45.2 TPY	GOOD COMBUSTION
VA-0206	PATOWMACK POWER PARTNERS, LIMITED PARTNERSHIP	LEESBURG	6/15/93	5/7/97	TURBINE, COMBUSTION, SIEMENS MODEL V84.2, 3	10 X109 SCF/YR NA	26 LB/HR	GOOD COMBUSTION OPERATING PRACTICES
WA-0275	TENASKA WASHINGTON PARTNERS, L.P.	BELLINGHAM	5/29/92	4/5/95	COGENERATION PLANT, COMBINED CYCLE	2 MMBTU/HR	20 PPM @ 15% O2	COMBUSTION CONTROL
WI-0067	WEPCO, PARIS SITE	PARIS	8/29/92	7/20/94	TURBINES, COMBUSTION (4)		25 LBS/HR (SEE NOTES)	

Table 4-3. Florida BACT CO Summary-Natural Gas-Fired CTGs

Permit Date	Source Name	Turbine Size (MW)	CO Emission Limit (ppmvd)	Control Technology
4/9/93	Kissimmee Utility Authority	40	30	Good combustion
4/9/93	Kissimmee Utility Authority	80	20	Good combustion
5/17/93	Central Florida Power, L.P. (Tiger Bay - Destec)	184	15	Good combustion
2/21/94	Polk Power Partners	84	25	Good combustion
2/24/94	Tampa Electric Company Polk Power Station	260	25	Good combustion
2/25/94	Florida Power Corp. Polk County Site	235	25	Good combustion
7/20/94	Pasco Cogen, Limited	42	28	Good combustion
3/7/95	Orange Cogeneration, L.P.	39	30	Good combustion
6/1/95	Panda-Kathleen	75	25	Good combustion
9/28/95	City of Key West	23	20	Good combustion
1/1/96	Seminole Electric Cooperative, Inc., Hardee Unit 3	140	20	Good combustion
5/1/98	City of Tallahassee Purdom Unit 8	160	25	Good combustion
7/10/98	City of Lakeland McIntosh Unit 5	250	25	Good combustion
12/4/98	Santa Rosa Energy Center	167	9	Good combustion

Source: FDEP, 1998.

Table 4-4. Direct and Indirect Capital Costs for CO Catalyst Installed on Westinghouse 501F CT

Cost Component/CT	Cost	Basis of Cost Component
<u>Direct Capital Costs</u>		
CO Associated Equipment	$100,000	Vendor Quote
Instrumentation	$10,000	10% of SCR Associated Equipment
Sales Tax		6% of SCR Associated Equipment/Catalyst
Freight	$35,000	5% of SCR Associated Equipment/Catalyst
Total Direct Capital Costs (TDCC)	$145,000	
<u>Direct Installation Costs</u>		
Foundation and supports	$59,600	8% of TDCC and RCC;OAQPS Cost Control Manual
Handling & Erection	$104,300	14% of TDCC and RCC;OAQPS Cost Control Manual
Electrical	$29,800	4% of TDCC and RCC;OAQPS Cost Control Manual
Piping	$14,900	2% of TDCC and RCC;OAQPS Cost Control Manual
Insulation for ductwork	$7,450	1% of TDCC and RCC;OAQPS Cost Control Manual
Painting	$7,450	1% of TDCC and RCC;OAQPS Cost Control Manual
Site Preparation	$5,000	Engineering Estimate
Buildings	$0	
Total Direct Installation Costs (TDIC)	$228,500	
Recurring Capital Costs (RCC)	$600,000	Catalyst; Vendor Based Estimate
Total Capital Costs	$973,500	Sum of TDCC, TDIC and RCC
<u>Indirect Costs</u>		
Engineering	$97,350	10% of Total Capital Costs; OAQPS Cost Control Manual
Construction and Field Expense	$48,675	5% of Total Capital Costs; OAQPS Cost Control Manual
Contractor Fees	$97,350	10% of Total Capital Costs; OAQPS Cost Control Manual
Start-up	$19,470	2% of Total Capital Costs; OAQPS Cost Control Manual
Performance Tests	$9,735	1% of Total Capital Costs; OAQPS Cost Control Manual
Contingencies	$97,350	10% of Total Capital Costs; OAQPS Cost Control Manual
Total Indirect Capital Cost (TInDC)	$369,930	
Total Direct, Indirect and Recurring Capital Costs (TDIRCC)	$1,343,430	Sum of TCC and TInCC

Table 4-5. Annualized Cost for CO Catalyst Installed on Westinghouse 501F CT

Cost Component/CT	Cost	Basis of Cost Estimate
Direct Annual Costs		
Operating Personnel	$6,240	8 hours/week at $15/hr
Supervision	$936	15% of Operating Personnel;OAQPS Cost Control Manual
Inventory Cost	$23,480	Capital Recovery (11.74%) for 1/3 catalyst
Catalyst Disposal Cost	$32,060	$28/1,000 lb/hr mass flow over 3 years; developed from vendor quotes
Contingency	$6,272	10% of Direct Annual Costs
Total Direct Annual Costs (TDAC)		
Energy Costs		
Heat Rate Penalty	$159,432	0.2% of MW output; EPA, 1993 (Page 6-20)
MW Loss Penalty	$43,680	2 days replacement energy costs @ $0.01 kWh each three period
Fuel Escalation	$6,093	Escalation of fuel over inflation; 3% of energy costs
Contingency	$20,921	10% of Energy Costs
Total Energy Costs (TDEC)	$230,126	
Indirect Annual Costs		
Overhead	$4,306	60% of Operating/Supervision Labor and Ammonia
Property Taxes		
Insurance	$13,434	1% of Total Capital Costs
Annualized Total Direct Capital	$87,279	11.74% Capital Recovery Factor of 10% over 20 years times sum of TDCC, TDIC and TInCC
Annualized Total Direct Recurring	$241,260	40.21% Capital Recovery Factor of 10% over 3 years times RCC
Total Indirect Annual Costs	$346,279	
Total Annualized Costs	$576,404	Sum of TDAC, TEC and TIAC
Cost Effectiveness	$2,177	Combustion Turbine

Table 4-6. RBLC NO_x Summary – Natural Gas-Fired Combustion Turbines

RBLC ID	Facility Name	City	Permit Dates Issuance	Permit Dates Last Update	Process Description	Thruput Rate	Emission Limits	Control System Description
AL-0069	INTERNATIONAL PAPER CO RIVERDALE MILL	SELMA	1/11/93	3/24/95	TURBINE, STATIONARY (GAS-FIRED) WITH DUCT BURNER	40 MW	0.08 LB/MMBTU (GAS)	LOW NOX BURNERS (ON THE DUCT BURNER) STEAM INJECTI ON INTO THE TURBINE
AL-0074	FLORIDA GAS TRANSMISSION COMPANY	MOBILE	8/5/93	5/12/94	TURBINE, NATURAL GAS	12 600 BHP	0.58 GM/HP HR	AIR-TO-FUEL RATIO CONTROL, DRY LOW NOX COMBUSTION
AL-0089	SOUTHERN NATURAL GAS COMPANY	SELMA	12/4/96	12/18/96	9160 HP GE MS3002G NATURAL GAS FIRED TURBINE		53 LB/HR	
AL-0096	MEAD COATED BOARD, INC	PHENIX CITY	3/12/97	5/31/97	COMBINED CYCLE TURBINE (25 MW)	569 MMBTU/HR	25 PPMVD@ 15% O2 (GAS)	DRY LOW NOX COMBUSTOR DESIGN FIRING GAS
AL-0109	SOUTHERN NATURAL GAS	AUBURN	3/2/98	4/24/98	9160 HP GE MODEL MS3002G NATURAL GAS FIRED TURBINE	9 160 HP	53 LB/HR	
AL-0115	ALABAMA POWER COMPANY	MCINTOSH	12/17/97	4/24/98	COMBUSTION TURBINE W/ DUCT BURNER (COMBINED CYCLE)	100 MW	15 PPM	DRY LOW NOX BURNERS
CA-0544	GOAL LINE, LP ICEFLOE	ESCONDIDO	11/3/92	8/4/94	TURBINE, COMBUSTION (NATURAL GAS) (42.4 MW)	386 MMBTU/HR	5 PPMVD @ 15% OXYGEN	WATER INJECTION & SCR W/ AUTOMATIC AMMONIA INJECT.
CA-0613	UNOCAL	WILMINGTON	7/18/89	12/5/94	TURBINE, GAS (SEE NOTES)		9 PPM @ 15% O2	SELECTIVE CATALYTIC REDUCTION (SCR), WATER INJECTN
CA-0768	NORTHERN CALIFORNIA POWER AGENCY	LODI	10/2/97	3/16/98	GE FRAME 5 GAS TURBINE	325 MMBTU/HR	25 PPMVD @ 15% O2	DRY LOW NOX BURNERS
CA-0774	SOUTHERN CALIFORNIA GAS COMPANY	WHEELER RIDGE	5/14/97	3/16/98	VARIABLE LOAD NATURAL GAS FIRED TURBINE COMPRESSOR	50 MMBTU/HR	25 PPMVD @ 15% O2	DRY LOW NOX COMBUSTOR
CA-0793	TEMPO PLASTICS	VISALIA	12/31/96	4/23/98	GAS TURBINE COGENERATION UNIT		0.109 LB/MMBTU	LOW-NOX COMBUSTOR
CA-0794	CALRESOURCES LLC		1/10/97	3/16/98	SOLAR MODEL 1100 SATURN GAS TURBINE	14 MMBTU/HR	69 PPMVD @15% O2	NO CONTROL
CO-0021	NORTHWEST PIPELINE CORPORATION	LA PLATA B' STATION'	5/29/92	7/20/94	TURBINE, SOLAR TAURUS	45 MMBTU/HR	95 PPMVD (UNTIL 11/98)	DRY LOW NOX COMBUSTOR (BY 11/01/98)
CO-0023	PHOENIX POWER PARTNERS	GREELEY	5/11/93	3/24/95	TURBINE (NATURAL GAS)	311 MMBTU/HR	22 PPM @ 15% O2	DRY LOW NOX COMBUSTION
FL-0068	ORANGE COGENERATION LP	BARTOW	12/30/93	1/13/95	TURBINE, NATURAL GAS, 2	366 MMBTU/H	15 PPM @ 15% O2	DRY LOW NOX COMBUSTOR
FL-0072	TIGER BAY LP	FT. MEADE	5/17/93	1/13/95	TURBINE, GAS	1,615 MMBTU/H	15 PPM @ 15% O2	DRY LOW NOX COMBUSTOR
FL-0074	FLORIDA GAS TRANSMISSION	PERRY	9/27/93	4/11/94	TURBINE, GAS	132 MMBTU/H	25 PPM @ 15% O2	DRY LOW NOX COMBUSTOR
FL-0078	KISSIMMEE UTILITY AUTHORITY	INTERCESSION CITY	4/7/93	1/13/95	TURBINE, NATURAL GAS	859 MMBTU/H	15 PPM @ 15% O2	DRY LOW NOX COMBUSTOR
FL-0078	KISSIMMEE UTILITY AUTHORITY	INTERCESSION CITY	4/7/93	1/13/95	TURBINE, NATURAL GAS	367 MMBTU/H	15 PPM @ 15% O2	DRY LOW NOX COMBUSTOR
FL-0080	AUBURNDALE POWER PARTNERS, LP	AUBURNDALE	12/14/92	1/13/95	TURBINE,GAS	1,214 MMBTU/H	15 PPMVD @ 15 % O2	DRY LOW NOX COMBUSTOR
FL-0082	FLORIDA POWER CORPORATION POLK COUNTY SITE	BARTOW	2/25/94	1/13/95	TURBINE, NATURAL GAS (2)	1,510 MMBTU/H	12 PPMVD @15 % O2	DRY LOW NOX COMBUSTOR
FL-0092	GAINESVILLE REGIONAL UTILITIES	GAINESVILLE	4/11/95	5/29/95	SIMPLE CYCLE COMBUSTION TURBINE, GAS/NO 2 OIL B-UP	74 MW	15 PPM AT 15% OXYGEN	DRY LOW NOX BURNERS GE FRAME UNIT, CAN ANNULAR COMBUSTORS
FL-0102	PANDA-KATHLEEN, L.P.	LAKELAND	6/1/95	5/20/96	COMBINED CYCLE COMBUSTION TURBINE (TOTAL 115MW)	75 MW	15 PPM @ 15% O2	DRY LOW NOX BURNER
FL-0109	KEY WEST CITY ELECTRIC SYSTEM	KEY WEST	9/28/95	5/31/96	TURBINE, EXISTING CT RELOCATION TO A NEW PLANT	23 MW	75 PPM @ 15% O2	WATER INJECTION
GA-0053	HARTWELL ENERGY LIMITED PARTNERSHIP	HARTWELL	7/28/92	3/24/95	TURBINE, GAS FIRED (2 EACH)	1,817 M BTU/HR	25 PPM @ 15% O2	MAXIMUM WATER INJECTION
GA-0056	GEORGIA POWER COMPANY, ROBINS TURBINE PROJECT	ROBINS AIR FORCE BASE	5/13/94	3/24/95	TURBINE, COMBUSTION, NATURAL GAS	80 MW	25 PPM	WATER INJECTION, FUEL SPEC: NATURAL GAS
GA-0063	MID-GEORGIA COGEN.	KATHLEEN	4/3/96	8/19/96	COMBUSTION TURBINE (2), NATURAL GAS	116 MW	9 PPMVD	DRY LOW NOX BURNER WITH SCR
KY-0053	KENTUCKY UTILITIES COMPANY	MERCER	3/10/92	3/24/95	TURBINE, #2 FUEL OIL/NATURAL GAS (8)	1,500 MM BTU/HR (EACH)	42 PPM @ 15% O2, N. GAS	WATER INJECTION
LA-0086	INTERNATIONAL PAPER	MANSFIELD	2/24/94	4/17/95	TURBINE/HRSG, GAS COGEN	338 MM BTU/HR TURBINE	25 PPMV 15% O2 TURBINE	DRY LOW NOX COMBUSTOR/COMBUSTION CONTROL
LA-0089	FORMOSA PLASTICS CORPORATION, LOUISIANA	BATON ROUGE	3/2/95	4/17/95	TURBINE/HRSG, GAS COGENERATION	450 MM BTU/HR	9 PPMV	DRY LOW NOX BURNER/COMBUSTION DESIGN AND CONTROL
LA-0091	GEORGIA GULF CORPORATION	PLAQUEMINE	3/26/98	4/21/97	GENERATOR, NATURAL GAS FIRED TURBINE	1,123 MM BTU/HR	25 PPMV-CORR. TO 15%O2	CONTROL NOX USING STEAM INJECTION
LA-0093	FORMOSA PLASTICS CORPORATION, BATON ROUGE PLANT	BATON ROUGE	3/7/97	4/28/97	TURBINE/HSRG, GAS COGENERATION	450 MM BTU/HR	9 PPMV	DRY LOW NOX BURNER/COMBUSTION DESIGN AND CONSTRUCTION.
LA-0098	UNION CARBIDE CORPORATION	HAHNVILLE	9/22/95	5/31/97	GENERATOR, GAS TURBINE	1,313 MM BTU/HR	25 PPMV CORR. TO 15% O2	DRY LOW NOX COMBUSTOR
MA-0015	PEABODY MUNICIPAL LIGHT PLANT	PEABODY	11/30/89	3/24/95	TURBINE, 38 MW NATURAL FAS FIRED	412 MMBTU/HR	25 PPM @ 15% O2	WATER INJECTION
MD-0017	SOUTHERN MARYLAND ELECTRIC COOPERATIVE (SMECO)	EAGLE HARBOR	10/1/89	3/24/95	TURBINE, NATURAL GAS FIRED ELECTRIC	90 MW	199 LB/HR	WATER INJECTION
MD-0018	PEPCO - CHALK POINT PLANT	EAGLE HARBOR	8/25/90	7/20/94	TURBINE, 105 MW NATURAL GAS FIRED ELECTRIC	105 MW	77 PPM @ 15% O2	DRY PREMIX AND WATER INJECTON
MD-0018	PEPCO - CHALK POINT PLANT	EAGLE HARBOR	8/25/90	7/20/94	TURBINE, 84 MW NATURAL GAS FIRED ELECTRIC	84 MW	25 PPM @ 15% O2	QUIET COMBUSTION AND WATER INJECTION
MD-0019	BALTIMORE GAS & ELECTRIC - PERRYMAN PLANT	PERRYMMAN		3/24/95	TURBINE, 140 MW NATURAL GAS FIRED ELECTRIC	140 MW	15 PPM @ 15% O2	DRY BURN LOW NOX BURNERS
MD-0021	PEPCO - STATION A	DICKERSON	5/31/90	7/20/94	TURBINE, 124 MW NATURAL GAS FIRED	125 MW	42 PPM @ 15% O2	WATER INJECTION
MS-0030	SOUTHERN NATURAL GAS COMPANY	BAY SPRINGS	12/17/96	3/24/97	TURBINE, NATURAL GAS-FIRED	9,160 HORSEPOWER	110 PPMV @ 15% O2, DRY	PROPER TURBINE DESIGN AND OPERATION
NC-0055	DUKE POWER CO. LINCOLN COMBUSTION TURBINE STATION	LOWESVILLE	12/20/91	3/24/95	TURBINE, COMBUSTION	1,247 MM BTU/HR	287 LB/HR	MULTINOZZLE COMBUSTOR, MAXIMUM WATER INJECTION
NC-0055	DUKE POWER CO. LINCOLN COMBUSTION TURBINE STATION	LOWESVILLE	12/20/91	3/24/95	TURBINE, COMBUSTION	1,313 MM BTU/HR	119 LB/HR	MULTINOZZLE COMBUSTOR, MAXIMUM WATER INJECTION
NJ-0009	NEWARK BAY COGENERATION PARTNERSHIP	NEWARK	11/1/90	7/7/93	TURBINE, NATURAL GAS FIRED	585 MMBTU/HR	0.033 LB/MMBTU	STEAM INJECTION AND SCR
NJ-0010	PEDRICKTOWN COGENERATION LIMITED PARTNERSHIP	OLDMANS TOWNSHIP	2/23/90	4/30/93	TURBINE, NATURAL GAS FIRED	1,000 MMBTU/HR	0.044 LB/MMBTU	STEAM INJECTION AND SCR
NJ-0011	LINDEN COGENERATION TECHNOLOGY	LINDEN	1/21/92	4/30/93	TURBINE, NATURAL GAS FIRED	50 X E12 BTU/YR	33.8 LB/HR	STEAM INJECTION AND SCR
NJ-0013	LAKEWOOD COGENERATION, L.P.	LAKEWOOD TOWNSHIP	4/1/91	5/29/95	TURBINES (NATURAL GAS) (2)	1,190 MMBTU/HR (EACH)	0.033 LB/MMBTU	SCR, DRY LOW NOX BURNER
NJ-0017	NEWARK BAY COGENERATION PARTNERSHIP, L.P.	NEWARK	6/9/93	5/29/95	TURBINES, COMBUSTION, NATURAL GAS-FIRED (2)	617 MMBTU/HR (EACH)	8.3 PPMDV	SCR
NM-0021	WILLIAMS FIELD SERVICES CO. - EL CEDRO COMPRESSOR	BLANCO	10/29/93	3/2/94	TURBINE, GAS-FIRED	11,257 HP	42 PPM @ 15% O2	SOLONOX COMBUSTOR, DRY LOW NOX TECHNOLOGY
NM-0022	MARATHON OIL CO. - INDIAN BASIN N.G. PLAN	CARLSBAD	1/11/95	4/28/95	TURBINES, NATURAL GAS (2)	5,500 HP	7.4 LBS/HR	LEAN-PREMIXED COMBUSTION TECHNOLOGY. DRY/LOW NOX
NM-0024	MILAGRO, WILLIAMS FIELD SERVICE	BLOOMFIELD		5/29/95	TURBINE/COGEN, NATURAL GAS (2)	900 MMCF/DAY	9 PPM @ 15% O2	DRY LOW NOX (GENERAL ELECTRIC MODEL PG6541B)
NM-0028	SOUTHWESTERN PUBLIC SERVICE CO/CUNNINGHAM STATION	HOBBS	11/4/96	12/30/96	COMBUSTION TURBINE, NATURAL GAS	100 MW	15 PPM (SEE FAC. NOTES)	DRY LOW NOX COMBUSTION
NM-0029	SOUTHWESTERN PUBLIC SERVICE COMPANY/CUNNINGHAM STA	HOBBS	2/15/97	3/31/97	COMBUSTION TURBINE, NATURAL GAS	100 MW	SEE FACILITY NOTES	DRY LOW NOX COMBUSTION
NM-0031	LORDSBURG L.P.	LORDSBURG	6/18/97	9/29/97	TURBINE, NATURAL GAS-FIRED, ELEC. GEN.	100 MW	74.4 LBS/HR	DRY LOW-NOX TECHNOLOGY WHICH ADOPTS STAGED OR SCHEDULED COMBUSTION.
NV-0017	NEVADA POWER COMPANY, HARRY ALLEN PEAKING PLANT	LAS VEGAS	9/18/92	3/24/95	COMBUSTION TURBINE ELECTRIC POWER GENERATION	600 MW (8 UNITS 75 EACH)	68.6 TPY (EACH TURBINE)	LOW NOX COMBUSTOR
NV-0018	NEVADA COGENERATION ASSOCIATES #2	LAS VEGAS	1/17/91	3/24/95	COMBINED-CYCLE POWER GENERATION	85 MW POWER OUTPUT	81.76 LBS/HR	SELECTIVE CATALYTIC SYSTEM ON ONE UNIT
NY-0044	BROOKLYN NAVY YARD COGENERATION PARTNERS L.P.	NEW YORK CITY	6/6/95	8/30/95	TURBINE, NATURAL GAS FIRED	240 MW	3.5 PPM @ 15% O2	SCR
NY-0045	SELKIRK COGENERATION PARTNERS, L.P.	SELKIRK	6/18/92	9/13/94	COMBUSTION TURBINES (2) (252 MW)	1,173 MMBTU/HR (EACH)	9 PPM GAS	STEAM INJECTION AND SCR
NY-0045	SELKIRK COGENERATION PARTNERS, L.P.	SELKIRK	6/18/92	9/13/94	COMBUSTION TURBINE (79 MW)	1,173 MMBTU/HR	25 PPM GAS	STEAM INJECTION
NY-0046	SARANAC ENERGY COMPANY	PLATTSBURGH	7/31/92	9/13/94	TURBINES, COMBUSTION (2) (NATURAL GAS)	1,123 MMBTU/HR (EACH)	9 PPM	SCR
NY-0047	PASNY/HOLTSVILLE COMBINED CYCLE PLANT	HOLTSVILLE	9/1/92	9/13/94	TURBINE, COMBUSTION GAS (150 MW)	1,146 MMBTU/HR (GAS)*	9 PPM	DRY LOW NOX
NY-0048	KAMINE/BESICORP CORNING L.P.	SOUTH CORNING	11/5/92	9/13/94	TURBINE, COMBUSTION (79 MW)	653 MMBTU/HR	9 PPM	DRY LOW NOX OR SCR
NY-0049	KAMINE/BESICORP BEAVER FALLS COGENERATION FACILITY	BEAVER FALLS	11/9/92	9/13/94	TURBINE, COMBUSTION (NAT. GAS & OIL FUEL) (79MW)	650 MMBTU/HR	9 PPM	DRY LOW NOX OR SCR
NY-0050	SITHE/INDEPENDENCE POWER PARTNERS	OSWEGO	11/24/92	9/13/94	TURBINES, COMBUSTION (4) (NATURAL GAS) (1012 MW)	2,133 MMBTU/HR (EACH)	4.5 PPM	SCR AND DRY LOW NOX
NY-0060	PROJECT ORANGE ASSOCIATES	SYRACUSE	12/1/93	3/31/95	GE LM-5000 GAS TURBINE	550 MMBTU/HR	25 PPM, 47 LB/HR	STEAM INJECTION, FUEL SPEC: NATURAL GAS ONLY

Table 4-6. RBLC NO_x Summary – Natural Gas-Fired Combustion Turbines

RBLC ID	Facility Name	City	Permit Dates Issuance	Last Update	Process Description	Thruput Rate	Emission Limits	Control System Description
NY-0080	PROJECT ORANGE ASSOCIATES	SYRACUSE	12/1/93	3/31/95	STACK (TURBINE AND DUCT BURNER)	715 MMBTU/HR	26 PPM, 59 LB/HR	NO CONTROLS FOR NOX ON STACK *SEE TURBINE NOX DATA
OH-0218	CNG TRANSMISSION	WASHINGTON COURT HOUS	8/12/92	4/5/95	TURBINE (NATURAL GAS) (3)	5,500 HP (EACH)	1.6 G/HP-HR*	LOW NOX COMBUSTION
OR-0009	PACIFIC GAS TRANSMISSION COMPANY	MADRAS	6/19/90	7/20/94	TURBINE GAS, COMPRESSOR STATION	110 MMBTU/HR	199 PPM @ 15% O2	LOW NOX BURNER DESIGN
OR-0010	PORTLAND GENERAL ELECTRIC CO.	BOARDMAN	5/31/94	8/6/97	TURBINES, NATURAL GAS (2)	1,720 MMBTU	4.5 PPM @ 15% O2	SCR
OR-0011	HERMISTON GENERATING CO.	HERMISTON	4/1/94	5/1/95	TURBINES, NATURAL GAS (2)	1,696 MMBTU	4.5 PPM @ 15% O2	SCR
PA-0098	GRAYS FERRY CO. GENERATION PARTNERSHIP	PHILADELPHIA	11/4/92	7/20/94	TURBINE (NATURAL GAS & OIL)	1,150 MMBTU	9 PPMVD (NAT. GAS)*	DRY LOW NOX BURNER, COMBUSTION CONTROL
PA-0099	FLEETWOOD COGENERATION ASSOCIATES	FLEETWOOD	4/22/94	11/22/94	NG TURBINE (GE LM6000) WITH WASTE HEAT BOILER	360 MMBTU/HR	21 LB/HR	SCR WITH LOW NOX COMBUSTORS
PA-0130	PROCTOR AND GAMBLE PAPER PRODUCTS CO (CHARMIN)	MEHOOPANY	5/31/95	11/27/95	TURBINE, NATURAL GAS	580 MMBTU/HR	55 PPM @ 15% O2	STEAM INJECTION
PA-0148	BLUE MOUNTAIN POWER, LP	RICHLAND	7/31/96	9/23/96	COMBUSTION TURBINE WITH HEAT RECOVERY BOILER	153 MW	4 PPM @ 15% O2	DRY LNB WITH SCR WATER INJECTION IN PLACE WHEN FIRING OIL
PA-0149	BUCKNELL UNIVERSITY	LEWISBURG	11/26/97	11/30/97	NG FIRED TURBINE, SOLAR TAURUS T-7300S	5 MW	25 PPMV@15%O2	SOLONOX BURNER: LOW NOX BURNER
PR-0004	ECOELECTRICA, L P	PENUELAS	10/1/96	5/6/98	TURBINES, COMBINED-CYCLE COGENERATION	461 MW	80 LB/HR	STEAM/WATER INJECTION AND SELECTIVE CATALYTIC REDUCTION (SCR).
TX-0231	WEST CAMPUS COGENERATION COMPANY	COLLEGE STATION	5/2/94	10/31/94	GAS TURBINES	75 MW (TOTAL POWER)	200 TPY	INTERNAL COMBUSTION CONTROLS
VA-0189	GORDONSVILLE ENERGY L.P.	FAIRFAX	9/25/92	3/24/95	TURBINES (2) (EACH WITH A SF)	2 X10(9) BTU/HR N GAS	9 PPMOV/UNIT @ 15% O2	SCR WITH WATER INJECTION
VA-0189	GORDONSVILLE ENERGY L.P.	FAIRFAX	9/25/92	3/24/95	TURBINE FACILITY, GAS	1,331 X10(7) SCF/Y NAT GAS	245 TOTAL TPY	SELECTIVE CATALYTIC REDUCTION (SCR) W/ WATER INJEC
VA-0190	BEAR ISLAND PAPER COMPANY, L.P.	ASHLAND	10/30/92	5/7/97	TURBINE, COMBUSTION GAS	474 X10(6) BTU/HR N. GAS	9 PPM	SELECTIVE CATALYTIC REDUCTION (SCR)
VA-0190	BEAR ISLAND PAPER COMPANY, L.P.	ASHLAND	10/30/92	5/7/97	TURBINE, COMBUSTION GAS (TOTAL)		69.7 TPY	SCR
VA-0206	PATOWMACK POWER PARTNERS, LIMITED PARTNERSHIP	LEESBURG	9/15/93	5/7/97	TURBINE, COMBUSTION, SIEMENS MODEL V84.2, 3	10 X109 SCF/YR NAT GAS	131 LB/HR(GAS), 339 OIL	DRY LOW NOX COMBUSTOR, DESIGN, WATER INJECTION
WA-0274	NORTHWEST PIPELINE COMPANY	SUMAS	8/13/92	4/5/95	TURBINE, GAS-FIRED	12,100 HP	196 PPM @ 15% O2	ADVANCED DRY LOW NOX COMBUSTOR (BY 07/01/95)
WA-0275	TENASKA WASHINGTON PARTNERS, L.P.	BELLINGHAM	5/29/92	4/5/95	COGENERATION PLANT, COMBINED CYCLE	2 MMBTU/HR	7 PPM @ 15% O2 (GAS)	STAGED LOW NOX DUCT BURNERS, STEAM INJECTION, SELECTIVE CATALYTIC RED
WI-0067	WEPCU, PARIS SITE	PARIS	8/29/92	7/20/94	TURBINES, COMBUSTION (4)		25 PPM @ 15% O2	GOOD COMBUSTION PRACTICES

Source: RBLC, 1998.

Table 4-7. Florida BACT NOx Summary-Natural Gas-Fired CTGs

Permit Date	Source Name	Turbine Size (MW)	NOx Emission Limit (ppmvd)	Control Technology
8/17/92	Orlando Cogeneration, L.P.	79	15	Dry low-NOx combustors
8/17/92	Florida Power Corp. University of Florida	43	25	Steam injection
12/17/92	Auburndale Power Partners	104	25	Steam injection
			15	Steam injection
4/9/93	Kissimmee Utility Authority	40	25	Water injection
			15	Dry low-NOx combustors
4/9/93	Kissimmee Utility Authority	80	25	Water injection
			15	Dry low-NOx combustors
5/17/93	Central Florida Power, L.P. (Tiger Bay - Destec)	184	25	Dry low-NOx combustors
		184	15	Dry low-NOx combustors
2/21/94	Polk Power Partners	84	25	Dry low-NOx combustors
			15	Dry low-NOx combustors
2/24/94	Tampa Electric Company Polk Power Station	260	25	Nitrogen diluent injection
2/25/94	Florida Power Corp. Polk County Site	235	12	Dry low-NOx combustors/SCR
7/20/94	Pasco Cogen, Limited	42	25	Wet injection
3/7/95	Orange Cogeneration, L.P.	39	25	Dry low-NOx combustors
4/11/95	Gainesville Regional Utilities Deerhaven CT3	74	15	Dry low-NOx combustors
6/1/95	Panda-Kathleen	75	15	Dry low-NOx combustors
9/28/95	City of Key West (relocated unit)	23	75	Water injection
1/1/96	Seminole Electric Cooperative, Inc., Hardee Unit 3	140	15	Dry low-NOx combustors
5/98	City of Tallahassee Purdom Unit 8	160	12	Dry low-NOx combustors
7/10/98	City of Lakeland McIntosh Unit 5	250	25	Dry low-NOx combustors
7/10/98	City of Lakeland McIntosh Unit 5	250	9	Dry low-NOx combustors or SCR (effective 5/1/2002)
12/4/98	Santa Rosa Energy Center	167	6	SCR
		167	9	Dry low-NOx combustors

Source: FDEP, 1998.

Table 4-8. Capital Cost for Selective Catalytic Reduction for Westinghouse 501F Combustion Turbine with HRSG (35 ppmvd to 6 ppmvd - gas only)

Cost Component/CT	Cost	Basis of Cost Component
Direct Capital Costs		
SCR Associated Equipment	$593,750	Vendor Based Estimate
Ammonia Storage Tank	$126,101	$35 per 1,000 lb mass flow developed from vendor quotes
HRSG Modification	$432,346	$120 per 1,000 lb mass flow developed from vendor quotes
Instrumentation	$59,375	10% of SCR Associated Equipment
Taxes	$82,313	6% of SCR Associated Equipment and Catalyst
Freight	$68,594	5% of SCR Associated Equipment
Total Direct Capital Costs (TDCC)	$1,362,478	
Direct Installation Costs		
Foundation and supports	$171,248	8% of TDCC and RCC;OAQPS Cost Control Manual
Handling & Erection	$299,684	14% of TDCC and RCC;OAQPS Cost Control Manual
Electrical	$85,624	4% of TDCC and RCC;OAQPS Cost Control Manual
Piping	$42,812	2% of TDCC and RCC;OAQPS Cost Control Manual
Insulation for ductwork	$21,406	1% of TDCC and RCC;OAQPS Cost Control Manual
Painting	$21,406	1% of TDCC and RCC;OAQPS Cost Control Manual
Site Preparation	$5,000	Engineering Estimate
Buildings	$15,000	Engineering Estimate
Total Direct Installation Costs (TDIC)	$662,181	
Recurring Capital Costs (RCC)	$778,125	Catalyst; Vendor Based Estimate
Total Capital Costs (TCC)	$2,802,783	Sum of TDCC, TDIC and RCC
Indirect Costs		
Engineering	$280,278	10% of Total Capital Costs; OAQPS Cost Control Manual
PSM/RMP Plan	$75,000	Engineering Estimate
Construction and Field Expense	$140,139	5% of Total Capital Costs; OAQPS Cost Control Manual
Contractor Fees	$280,278	10% of Total Capital Costs; OAQPS Cost Control Manual
Start-up	$56,056	2% of Total Capital Costs; OAQPS Cost Control Manual
Performance Tests	$28,028	1% of Total Capital Costs; OAQPS Cost Control Manual
Contingencies	$280,278	10% of Total Capital Costs; OAQPS Cost Control Manual
Total Indirect Capital Cost (TInCC)	$1,140,058	
Total Direct, Indirect and Recurring Capital Costs (TDIRCC)	$3,942,841	Sum of TCC and TInCC

Table 4-9. Annualized Cost for Selective Catalytic Reduction for Westinghouse 501F Combustion Turbine with HRSG (35 ppmvd to 6 ppmvd - gas only)

Cost Component/CT	Cost	Basis of Cost Component
Direct Annual Costs		
Operating Personnel	18,720	24 hours/week at $15/hr
Supervision	2,808	15% of Operating Personnel;OAQPS Cost Control Manual
Ammonia	384,520	$300 per ton NH_3 for Aqueous
PSM/RMP Update	25,000	Engineering Estimate
Inventory Cost	30,451	Capital Recovery (11.74%) for 1/3 catalyst
Catalyst Disposal Cost	33,627	$28/1,000 lb/hr mass flow over 3 years; developed from vendor quotes
Contingency	49,513	10% of Direct Annual Costs
Total Direct Annual Costs (TDAC)	544,638	
Energy Costs		
Electrical	35,040	80kW/h @ $0.05/kWh times Capacity Factor
MW Loss and Heat Rate Penalty	638,072	0.5% of MW output; EPA, 1993 (Page 6-20) and $3/mmBtu additional fuel costs
Replacement Energy	58,094	3 days outage each 3 years @ $0.01/kWhr
Fuel Escalation	20,193	Escalation of fuel over inflation; 3% of energy costs
Contingency	75,140	10% of Energy Costs
Total Energy Costs (TEC)	826,540	
Indirect Annual Costs		
Overhead	$243,629	60% of Operating/Supervision Labor and Ammonia
Property Taxes	$39,428	1% of Total Capital Costs
Insurance	$39,428	1% of Total Capital Costs
Annualized Total Direct Capital	$371,538	11.74% Capital Recovery Factor of 10% over 20 years times sum of TDCC, TDIC and TInCC
Annualized Total Direct Recurring	$312,884	40.21% Capital Recovery Factor of 10% over 3 years times RCC
Total Indirect Annual Costs (TIAC)	$1,006,907	
Total Annualized Costs	$2,378,085	Sum of TDAC, TEC and TIAC
Cost Effectiveness	$2,694	
Tons NO_x Emissions Removed	882.82	82.3% Removal by SCR System; 35 ppmvd (243.25 lb/hr) to 6 ppmvd (41.7 lb/hr)

Table 4-10. Summary of Proposed BACT Control Technologies and Emission Limits

Pollutant		Control Technology	Proposed BACT Emission Limits (ppmvd)[a]	(lb/hr)
Siemens-Westinghouse 501FD CTs				
PM/PM_{10}	(gas)	Natural gas and limited use of low-sulfur	10%[b]	NA
	(oil)	fuel oil	20%[b]	NA
		Efficient and complete combustion		
CO	(gas)	Efficient and complete combustion	25	86
	(oil)		30	92
VOC	(gas)	Efficient and complete combustion	8	16
	(oil)		11	22
NO_x	(gas)	Use of dry low-NO_x burners and SCR	6	42[c]
	(oil)		42	303[c,d]
$S0_2/H_2SO_4$ mist		Natural gas and limited use of low-sulfur fuel oil	NA	NA

a - the ppmvd values are the computational basis for the lb/hr numbers; the lb/hr numbers are the actual emission limitations.
b - percent opacity, a surrogate for PM limits
c - based on a 24 hr block average as measured by CEMS
d - based on a FBN content of 0.015% or less; the emission limit for NOx is adjusted for higher FBN contents up to a max of 0.030%

5.0 AMBIENT AIR QUALITY MONITORING DATA ANALYSIS

5.1 PSD PRECONSTRUCTION MONITORING APPLICABILITY

Based on the worst-case proposed source emissions data and air quality modelling results for the proposed Power Block 2, ambient air quality monitoring is not required for SO_2, PM_{10}, or NO_2 because the maximum predicted impacts are less than the PSD pre-construction monitoring *de minimis* values for those pollutants (FDEP Rule 62-212.400). Table 5-1 compares the maximum predicted concentrations with the *de minimis* levels. For ozone (O_3), annual volatile organic compound (VOC) emissions from Hines Power Block 2 are predicted to exceed 100 tons per year, so ambient monitoring data were obtained from existing monitoring sites in the region surrounding the plant site.

5.2 OZONE AIR QUALITY MONITORING DATA

Regional FDEP ambient ozone monitoring data are available that can be used to characterize the existing conditions in the vicinity of the site. The FDEP data from these monitors for 1996 and 1997 are summarized in Table 5-2.

Ambient ozone data have been collected by FDEP in the Lakeland, Tampa, St. Petersburg, and Sarasota metropolitan areas. Given the rural nature of the Hines Energy Complex site, existing concentrations should be lower than in these urbanized areas. Data from Lakeland and Hillsborough County monitors for 1996 and 1997, which are the two most recent years available, are given in Table 5-2 because these monitors are located closest to the Hines Energy Complex.

The Tampa Bay region, as well as most of Florida and the Southeast, experienced elevated O_3 levels in May 1998. These data have not been quality-assured, and the DEP has petitioned EPA to exclude some of the data due to outside influences such as smoke from large fires burning in Mexico at the time.

The 1996 and 1997 ambient air quality data show that Polk County is attaining the AAQS for ozone. In addition, Polk County is in compliance with all other ambient air quality standards.

TABLE 5-1
SUMMARY OF MAXIMUM MODELED POWER BLOCK 2 IMPACTS VS. PSD MONITORING *DE MINIMIS* VALUES

Pollutant	Averaging Period	Highest Modeled Concentration (ug/m^3)	PSD Demin. Level (ug/m^3)	Significance
Sulfur Dioxide (SO_2)	24-Hour	4.04	13	NO
Particulate Matter (PM_{10})	24-Hour	1.79	10	NO
Nitrogen Dioxide (NO_2)	Annual	0.33	14	NO

FPC, December 1998

TABLE 5-2 REGIONAL OZONE AMBIENT AIR QUALITY DATA				
POLLUTANT	LOCATION	SITE #	CONCENTRATION (ug/m³)	
			1-HOUR	
			HIGH	2ND HI
O_3 (1996)	HILLSBOROUGH BAY	1800081G03	263	212
	TAMPA	4360035G02	246	220
	TAMPA	4360065G01	238	222
	TAMPA	4360068G01	195	167
	LAKELAND	2160005F01	187	167
	LAKELAND	2160006F01	195	187
O_3 (1997)	HILLSBOROUGH BAY	1800081G03	210	206
	TAMPA	4360035G02	226	220
	TAMPA	4360065G01	218	214
	TAMPA	4360068G01	216	204
	LAKELAND	2160005F01	204	200
	LAKELAND	2160006F01	216	197

6.0 AIR QUALITY MODELLING APPROACH

This section summarizes the air quality modelling protocol and input parameters utilized in the air impact determinations presented in Section 7.0. Included are descriptions of the models, meteorology, options selected, listings of modelling parameters for the proposed facilities and existing sources, receptor locations, and step-by-step procedures that were used to develop the necessary projected impacts.

The scope of the required modelling analysis is limited to those pollutants that were determined to be subject to PSD review in Section 3.0, Table 2-5 (CO, NO_x, SO_2, PM, VOC (O_3), and sulfuric acid mist). Not all of the pollutants will require the full PSD air quality analysis; for some, impact identification of the new facilities alone will be sufficient.

As indicated in Table 2-5, there will be a significant increase in VOC emissions, triggering PSD review for ozone. Ozone formation cannot be simulated with a simple Gaussian dispersion model. However, the U.S. EPA Guideline on Air Quality Models (EPA, 1990a) indicates that "the use of models incorporating complex chemical mechanisms should be considered only on a case-by-case basis with proper demonstration of applicability. These are generally regional models not designed for the evaluation of individual sources but used primarily for region-wide evaluations." The proposed facility is not subject to a VOC emissions impact assessment and an ozone modelling analysis is not appropriate.

The proposed source emissions of sulfuric acid mist are shown in Table 2-5 to be above the PSD significant emission rates. However, the PSD regulations do not define significant impact levels nor are ambient air quality standards established for this pollutant. Hence, the air quality impact assessment for sulfuric acid mist is limited to prediction of the maximum impacts from the proposed facility.

6.1 GENERAL MODELLING APPROACH

The PSD regulations require an air quality impact assessment consisting of a proposed source significant impact area analysis, a PSD increment consumption analysis, an ambient air quality standards impact analysis, and an additional impacts analysis. These analyses are discussed in greater detail in the following sections under specific modelling methodologies. The modelling approach followed EPA and FDEP guidelines for determining compliance with applicable PSD increments and ambient air quality standards.

A screening analysis was performed to determine the worst-case emissions case to be used as input to the refined modelling analysis. In the refined analysis, the worst-case and five years of meteorological data were used to predict the highest ambient concentrations of applicable criteria pollutants. These results were compared to the PSD significance levels for each pollutant in order to determine whether additional modelling was necessary. All predicted maximum concentrations were less than the PSD significance values.

6.2 MODEL SELECTION AND OPTIONS

6.2.1 Dispersion Model Selection

The area surrounding the Hines Energy Complex has been determined to be a rural area based upon the technique for urban/rural determinations documented in the EPA "Guideline on Air Quality Models", which applies land use criteria. Based upon this determination, the rural dispersion option was used in both regulatory air quality dispersion models that were used for this application. The EPA SCREEN3 model was used to evaluate the load and ambient temperature conditions that are predicted to produce the highest ambient impacts. The resulting worst-case emissions were used as input to the refined ISCST3 dispersion model (Version 98226) for a comprehensive evaluation of the ambient air impacts of proposed Power Block 2. The ISCST3 model is a referenced EPA dispersion model recommended for use in urban or rural areas, and for application to point, area, and volume sources. The ISCST3 model can predict ambient pollutant concentrations and period of occurrence for 1-hour, 3-hour, 8-hour, 24-hour, and annual averaging periods at each receptor for each full year of hourly meteorological data used.

6.2.2 Dispersion Model Options

The model's Regulatory Default option was used for this analysis. The ISCST3 model was applied without terrain adjustment data because the area in which the Polk County Site is located has very little relief (e.g., a net change in ground level elevation in the range of only 10 feet). The ISCST3 model's building downwash options were applied because the stacks for the proposed sources will be less than the stack height at which downwash effects may occur.

In the 1992 PSD application for the Hines Energy Complex, expected emissions from both Power Block 1 and Power Block 2 were included in the dispersion modelling analysis. The analysis evaluated the total impact of the two power blocks with respect to PSD increment consumption and ambient air quality impacts. Power Block 1 has been constructed and is now operational. With approval from FDEP personnel obtained on November 23, 1998, it was determined that the analysis for proposed Power Block 2 should be updated to include use of the latest version of ISC and the most recently-approved five years of meteorological data. Therefore, this analysis re-evaluates the incremental impact of Power Block 2 on the ambient air quality surrounding the Hines Energy Complex. For purposes of model input, the two stacks for Power Block 2 were co-located; therefore, one source was input to the model.

The air quality impact assessment for PM assumed that all PM emissions were PM_{10} emissions. This assumption simplified the PM modelling analysis and makes for a conservative approach to modelling PM impacts.

6.3 METEOROLOGICAL DATA

The air quality modelling analysis used hourly preprocessed National Weather Service (NWS) surface meteorological data from Tampa, Florida, and concurrent twice-daily upper air soundings from Ruskin, Florida, for the years 1987-1991. The meteorological data were supplied by FDEP in the preprocessed format required by the ISCST3 model. The preprocessed hourly meteorological data file for each year of record used in the analysis contains randomized wind direction, wind speed, ambient temperature, atmospheric stability using the Turner (1970) stability classification scheme, and mixing heights. The anemometer height of 6.7 meters, used in the modelling analysis, was obtained from NWS Local Climatological Data summaries for Tampa.

6.4 EMISSIONS INVENTORY

6.4.1 Proposed Source

The proposed combined-cycle facility will have the capability of firing natural gas and low sulfur fuel oil. The fuel scenarios evaluated for the proposed source include natural gas firing at 100%, 80%, 65% and 50% load at 32°F, 59°F, and 105°F ambient temperature; and fuel oil firing at 100%, 80%, 65% and 50% load at 22°F, 59°F, and 105°F ambient temperature. The differences in the lowest temperatures between natural gas and oil are due to the so-called "shaft limit" difference when operating on these fuels. This limit is the point at which the greatest mass emissions occur.

The emissions inventories for the proposed source and fuel scenarios identified above are presented in Tables 6-1 through 6-6. The pollutant emission rates shown in those tables are representative of BACT as demonstrated in Section 4.0. The air quality modelling analysis for the proposed sources assumed that maximum design capacity emissions represent actual emissions for purposes of determining PSD increment consumption.

The proposed source worst-case fuel scenario was determined by modelling each temperature and load scenario for each fuel using the SCREEN3 model. In addition to the ambient temperature cases previously discussed, loads of 50%, 80%, and 100% were evaluated in the screening analysis. The results indicated that the full load case at 105°F. was the worst-case scenario for purposes of dispersion modelling for SO_2 and for NOx while firing oil. For CO, PM, and NOx while firing gas, the 50% load case was the worst-case scenario for dispersion modelling purposes. Complete SCREEN3 model outputs have been submitted to the FDEP under separate cover.

6.4.2 Existing Sources

The results of the proposed source significant impact area analysis (which is described in Section 7.0) indicated that the proposed facility's air quality impacts are less than the PSD significant impact levels. Therefore, no additional significant impact modelling analysis for PSD Class II increment consumption or ambient air quality standard impact is necessary.

6.5 RECEPTOR LOCATIONS

A description of the receptor grids used in this modelling analysis is presented below.

6.5.1 Receptor Grid for Proposed Source Significant Impact Analysis

This modelling analysis used a polar receptor grid beginning at 500 meters (m) and extending out to cover a 50 kilometer (km) radius centered over the proposed source. The polar grid consisted of 36 radials, each separated by 10-degree increments and extending outward at ring distances of 500 m, 1 km, and 1.5, 2.0, 2.5, 5.0, 10.0, 15.0, 20.0, 25.0, 30.0, 35.0, 40.0, 45.0, and 50.0 km with reference to the proposed source location.

In addition, receptors were placed at 100-meter intervals along the plant property boundary to assess the potential impact at the FPC property line. An additional Cartesian receptor grid with receptors placed at 100-meter intervals was input to assess concentrations near the property line closest to the source, which is to the southeast of the facility.

In total, the receptor grid consisted of 648 receptors and is shown in Figures 6-1 and 6-2.

The modelling results indicated no significant impacts for the PSD pollutants.

6.5.2 Receptor Grid for Class I PSD Analysis

A network of 13 discrete receptors was placed at the boundary of the Chassahowitzka National Wilderness Area (NWA) in order to reassess the potential incremental impact of the proposed source on that Class I area. The NWA receptors were obtained from the FDEP and were also used in the modelling analysis for the 1992 PSD application. The coordinates of these receptor points are listed in Table 6-7.

6.6 BUILDING DOWNWASH EFFECTS

Based on the building dimensions associated with structures planned at the Hines Energy Complex, the 38.1 meter stacks for the proposed Power Block 2 will be less than the calculated value (61.0 meters) at which downwash effects would not be expected to occur. Therefore, the potential for building downwash was considered in the modelling analysis.

The procedures used for addressing the effects of building downwash are those recommended in the ISC Dispersion Model User's Guide. The building height, length, and width are input to the Building Parameter Input Program (BPIP) model, which uses these parameters to create the effective wind direction-specific building dimensions for input to the model. For short stacks (i.e., physical stack height is less than $H_b + 0.5\, L_b$, where H_b is the building height and L_b is the lesser of the building height or projected width), the Schulman and Scire (1980) method is used. If this method is used, then direction-specific building dimensions are input for H_b and L_b for 36 radial directions, with each direction representing a 10-degree sector.

For cases where the physical stack is greater than $H_b + 0.5\,L_b$, the Huber-Snyder (1976) method is used. In the case of the proposed CC units, the HRSG structures are the dominant buildings of influence. The dimensions of the HRSG structures are 24.4 meters high (H_b) and 13.7 meters wide (M_W). Since the proposed stack height of 38.1 meters is more than $H_b + 0.5\,L_b$, only the Huber-Snyder downwash algorithm is used by the ISCST model.

TABLE 6-1

COMBUSTION TURBINE UNIT (165 MW)

ESTIMATED [1] PERFORMANCE ON NATURAL GAS

100% LOAD

CONDITIONS			
Ambient Temperature (°F)	32	59	105
Ambient Relative Humidity (%)	60	60	60
Load Condition (%)	100	100	100
Elevation (ft) (above MSL)	163	163	163
Maximum Heat Input Rate (MMBtu/hr)[2]	1,946	1,822	1,626
EMISSIONS (lb/hr)			
Carbon Monoxide (25 ppm)	91	86	75
Nitrogen Oxides (at 15% O_2) (6 ppmvd)[3]	45	42	38
Sulfur Dioxide	6.0	5.5	5.0
Particulate Matter (PM_{10})	9.8	9.3	8.5
Opacity (%)	10	10	10
Volatile Organic Compounds (8 ppmvd)	17	16	14
Sulfuric Acid Mist	0.60	0.55	0.50
STACK PARAMETERS			
Stack Height (ft)	125	125	125
Stack Diameter (ft)	19.0	19.0	19.0
Stack Gas Temperature (°F)	206	206	206
Stack Gas Exit Velocity (ft/sec)	64	61	55

Notes: (1) Emission estimates based on manufacturer's data

(2) For CTs the heat-input rate is based on the higher heating value (HHV) of the fuel (1,050 Btu/SCF).

(3) Not corrected to ISO conditions.

MSL = Mean Sea Level Neg. = Negligible

TABLE 6-2

COMBUSTION TURBINE UNIT (165 MW)

ESTIMATED [1] PERFORMANCE ON NATURAL GAS

80% LOAD

CONDITIONS			
Ambient Temperature (°F)	32	59	105
Ambient Relative Humidity (%)	60	60	60
Load Condition (%)	80	80	80
Elevation (ft) (above MSL)	163	163	163
Maximum Heat Input Rate (MMBtu/hr)[2]	1,657	1,561	1,408
EMISSIONS (lb/hr)			
Carbon Monoxide (25 ppm)	77	73	66
Nitrogen Oxides (at 15% O_2) (6 ppmvd)[3]	38	36	32
Sulfur Dioxide	5.0	4.7	4.3
Particulate Matter (PM_{10})	9.7	9.2	8.4
Opacity (%)	10	10	10
Volatile Organic Compounds (8 ppmvd)	14	13	12
Sulfuric Acid Mist	0.50	0.45	0.40
STACK PARAMETERS			
Stack Height (ft)	125	125	125
Stack Diameter (ft)	19.0	19.0	19.0
Stack Gas Temperature (°F)	201	201	201
Stack Gas Exit Velocity (ft/sec)	54	51	48

Notes: (1) Emission estimates based on manufacturer's data

(2) For CTs the heat-input rate is based on the higher heating value (HHV) of the fuel (1,050 Btu/SCF).

(3) Not corrected to ISO conditions.

MSL = Mean Sea Level   Neg. = Negligible

TABLE 6-3

COMBUSTION TURBINE UNIT (165 MW)

ESTIMATED [1] PERFORMANCE ON NATURAL GAS

50% LOAD

CONDITIONS			
Ambient Temperature (°F)	32	59	105
Ambient Relative Humidity (%)	60	60	60
Load Condition (%)	50	50	50
Elevation (ft) (above MSL)	163	163	163
Maximum Heat Input Rate (MMBtu/hr)[2]	1,171	1,113	1,011
EMISSIONS (lb/hr)			
Carbon Monoxide (200 ppm)	540	518	468
Nitrogen Oxides (at 15% O_2) (10 ppmvd)[3]	45	42	38
Sulfur Dioxide	3.5	3.4	3.1
Particulate Matter (PM_{10})	9.6	9.2	8.4
Opacity (%)	10	10	10
Volatile Organic Compounds (8 ppmvd)	31	30	27
Sulfuric Acid Mist	0.35	0.30	0.25
STACK PARAMETERS			
Stack Height (ft)	125	125	125
Stack Diameter (ft)	19.0	19.0	19.0
Stack Gas Temperature (°F)	201	201	201
Stack Gas Exit Velocity (ft/sec)	46	45	42

Notes: (1) Emission estimates based on manufacturer's data

(2) For CTs the heat-input rate is based on the higher heating value (HHV) of the fuel (1,050 Btu/SCF).

(3) Not corrected to ISO conditions.

MSL = Mean Sea Level   Neg. = Negligible

TABLE 6-4

COMBUSTION TURBINE UNIT (165 MW)

ESTIMATED [1] PERFORMANCE ON FUEL OIL

100% LOAD

CONDITIONS			
Ambient Temperature (°F)	22	59	105
Ambient Relative Humidity (%)	60	60	60
Load Condition (%)	100	100	100
Elevation (ft) (above MSL)	163	163	163
Maximum Heat Input Rate (MMBtu/hr)[2]	1,943	1,776	1,581
EMISSIONS (lb/hr)			
Carbon Monoxide (30 ppm)	113	92	92
Nitrogen Oxides (at 15% O_2) (42 ppmvd)[3]	332	303	270
Sulfur Dioxide	104	95	84
Particulate Matter (PM_{10})	46	43	37
Opacity (%)	20	20	20
Volatile Organic Compounds (8 ppmvd)	24	22	19
Sulfuric Acid Mist	10	9	8
STACK PARAMETERS			
Stack Height (ft)	125	125	125
Stack Diameter (ft)	19.0	19.0	19.0
Stack Gas Temperature (°F)	289	289	289
Stack Gas Exit Velocity (ft/sec)	74	69	62

Notes: (1) Emission estimates based on manufacturer's data

(2) For CTs the heat-input rate is based on the higher heating value (HHV) of the fuel (1,050 Btu/SCF).

(3) Not corrected to ISO conditions.

MSL = Mean Sea Level   Neg. = Negligible

TABLE 6-5

COMBUSTION TURBINE UNIT (165 MW)

ESTIMATED [1] PERFORMANCE ON FUEL OIL

80% LOAD

CONDITIONS			
Ambient Temperature (°F)	22	59	105
Ambient Relative Humidity (%)	60	60	60
Load Condition (%)	80	80	80
Elevation (ft) (above MSL)	163	163	163
Maximum Heat Input Rate (MMBtu/hr)[2]	1,590	1,467	1,323
EMISSIONS (lb/hr)			
Nitrogen Oxides (at 15% O_2) (42 ppmvd)[3]	269	248	224
Sulfur Dioxide	85	78	71
Particulate Matter (PM_{10})	46	41	37
Opacity (%)	20	20	20
Volatile Organic Compounds (8 ppmvd)	23	22	19
Sulfuric Acid Mist	8	7	6
STACK PARAMETERS			
Stack Height (ft)	125	125	125
Stack Diameter (ft)	19.0	19.0	19.0
Stack Gas Temperature (°F)	289	289	289
Stack Gas Exit Velocity (ft/sec)	72	67	61

Notes: (1) Emission estimates based on manufacturer's data
(2) For CTs the heat-input rate is based on the higher heating value (HHV) of the fuel (1,050 Btu/SCF).
(3) Not corrected to ISO conditions.
MSL = Mean Sea Level   Neg. = Negligible

TABLE 6-6
COMBUSTION TURBINE UNIT (165 MW)
ESTIMATED (1) PERFORMANCE ON FUEL OIL
50% LOAD

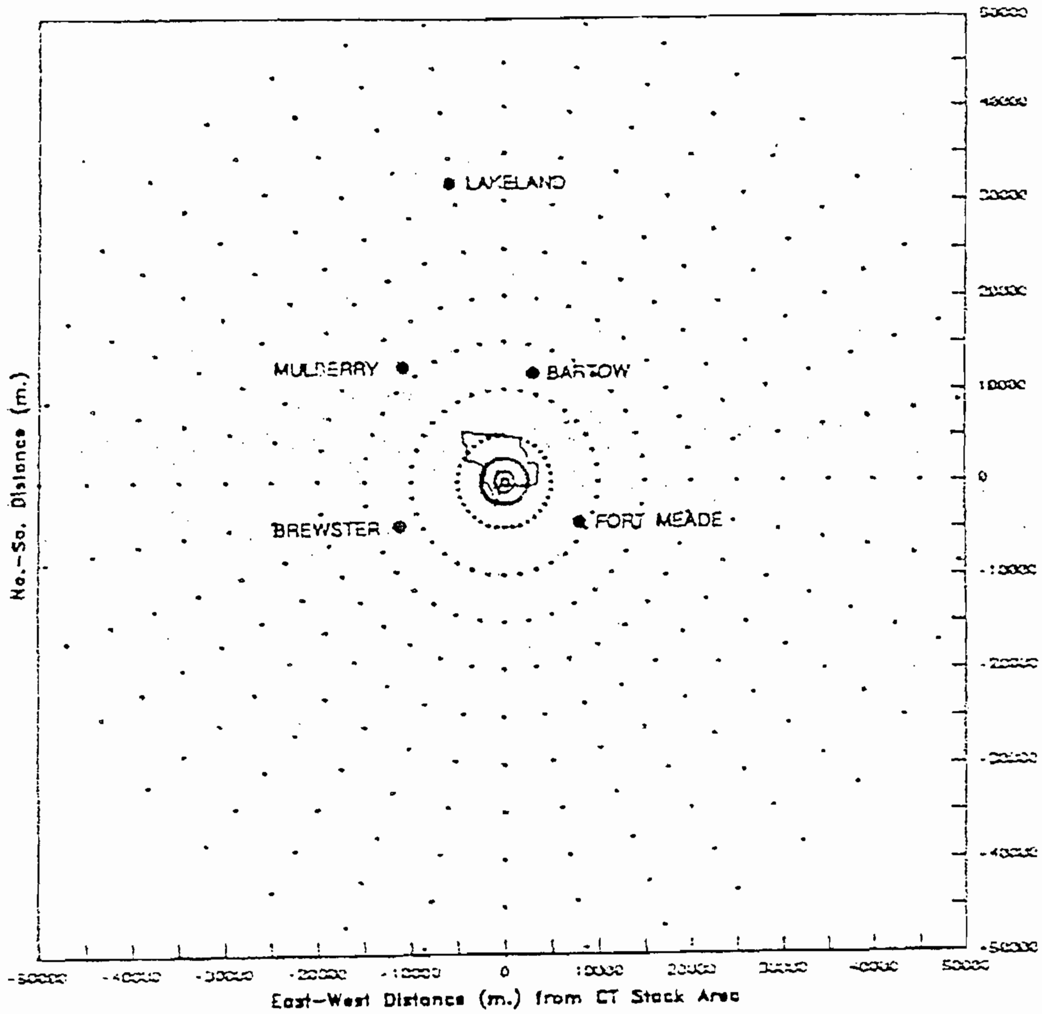
CONDITIONS			
Ambient Temperature (°F)	22	59	105
Ambient Relative Humidity (%)	60	60	60
Load Condition (%)	50	50	50
Elevation (ft) (above MSL)	163	163	163
Maximum Heat Input Rate (MMBtu/hr)(2)	1,150	1,063	966
EMISSIONS (lb/hr)			
Nitrogen Oxides (at 15% O_2) (42 ppmvd)(3)	192	177	161
Sulfur Dioxide	61	57	52
Particulate Matter (PM_{10})	46	41	39
Opacity (%)	20	20	20
Volatile Organic Compounds (8 ppmvd)	171	161	144
Sulfuric Acid Mist	6	5	5
STACK PARAMETERS			
Stack Height (ft)	125	125	125
Stack Diameter (ft)	19.0	19.0	19.0
Stack Gas Temperature (°F)	284	284	284
Stack Gas Exit Velocity (ft/sec)	57	54	50

Notes: (1) Emission estimates based on manufacturer's data
(2) For CTs the heat-input rate is based on the higher heating value (HHV) of the fuel (1,050 Btu/SCF).
(3) Not corrected to ISO conditions.
MSL = Mean Sea Level   Neg. = Negligible

TABLE 6-7
RECEPTOR GRID FOR PSD CLASS I AREA

Point	UTM Coordinates		Distance from Polk County Site *		
	East (km)	North (km)	X (km)	Y (km)	Distance (km)
1	340.3	3,165.7	-74.0	91.82	117.9
2	340.3	3,167.7	-74.0	93.82	119.5
3	340.3	3,169.8	-74.0	95.92	121.1
4	340.7	3,171.9	-73.6	98.02	122.6
5	342.0	3,174.0	-72.3	100.12	123.5
6	343.0	3,176.2	-71.3	102.32	124.7
7	343.7	3,178.3	-70.6	104.42	126.0
8	342.4	3,180.6	-71.9	106.72	128.7
9	341.1	3,183.4	-73.2	109.52	131.7
10	339.0	3,183.4	-75.3	109.52	132.9
11	336.5	3,183.4	-77.8	109.52	134.3
12	334.0	3,183.4	-80.3	109.52	135.8
13	331.5	3,183.4	-82.8	109.52	137.3

* Location of "zero point" for Hines Energy Complex is 414.300 km East; 3,073.880 km North



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Hines Energy Complex

FIGURE 6-1
RECEPTOR GRID FOR SIGNIFICANT IMPACT ANALYSIS

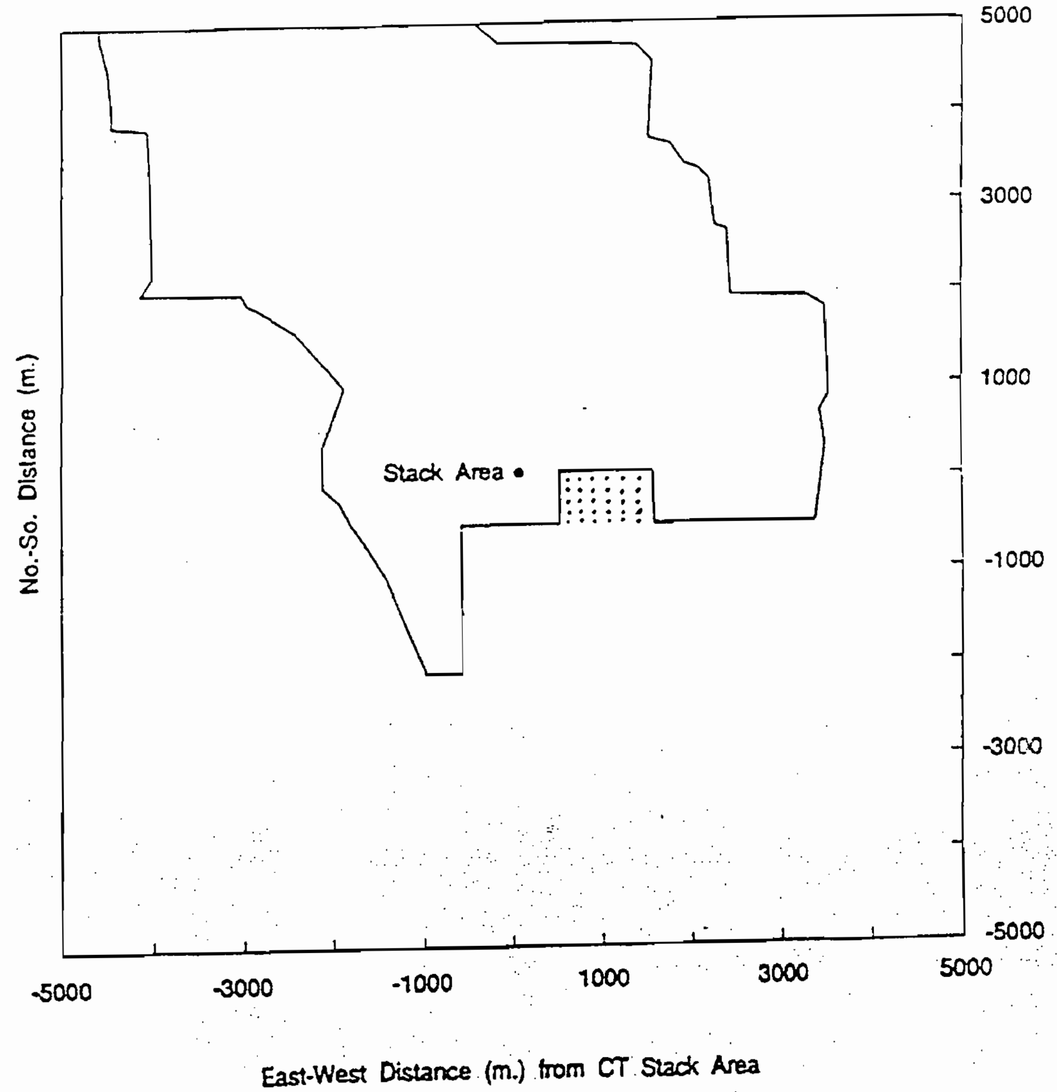

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FIGURE 6-2
ADDITONAL SIGNIFICANT IMPACT ANALYSIS RECEPTORS

7.0 AIR QUALITY IMPACT ANALYSIS RESULTS

This section summarizes the results of the modelling analyses conducted as described in Section 6.0.

7.1 Power Block 2

7.1.1 Worst-case Operation Analysis

As indicated in Section 6.4.1, the proposed CC facility was evaluated for both the primary fuel, natural gas, and the back-up fuel, fuel oil, to determine the worst-case impacts. Since the emissions on fuel oil are higher for the criteria pollutants than for natural gas, the analysis of short-term impacts focused on the fuel oil case. Based on the results of the SCREEN3, it was determined that 100% load would produce the maximum ground-level impacts, except for CO emissions, which are highest at 50% load. Therefore, full load conditions were modelled for all pollutants except CO. As previously discussed, the proposed Power Block 2 emissions input was for the 105°F case, since it produced the highest predicted impacts in the SCREEN3 analysis.

Subsequent runs for annual averages were made using the emissions and stack parameters associated with the conservative 105°F case, but took into account the maximum of 1000 hours per year of fuel oil firing and added 7,760 hours per year of emissions from natural gas firing.

7.1.2 Significant Impact Analysis

Once the worst-case operating scenario was determined, the next step in the analysis was to determine whether the ambient air quality impact from the proposed Power Block 2 is considered significant under the PSD rules. The worst-case emissions scenario for each pollutant was modeled at the receptor locations described in Section 6.5.1.

The results of the significant impact analysis are presented in Table 7-1. As indicated in Table 7-1, there were no predicted impacts greater than the PSD significance thresholds.

Thus, no further analysis is required for purposes of PSD increment consumption and AAQS compliance analysis. A complete set of the ISCST3 model output files have been submitted to the FDEP under separate cover.

7.2 PSD INCREMENT ANALYSIS

7.2.1 Class II Area

Because the maximum predicted ambient air quality impacts are less than the PSD significance levels, no additional PSD Class II increment analysis is required.

7.2.2 Class I Area

Although the proposed project will be located approximately 118 km from the nearest boundary of the nearest Class I PSD area, which is the Chassahowitzka National Wilderness Area (NWA), the impacts of the proposed project were modelled. In its proposed New Source Review reform package, EPA has proposed PSD significance levels for Class I areas. FDEP has approved the use of these proposed values for purposes of assessing significant impacts at Class I areas in Florida (personal communication with Mr. Cleve Holladay, November 23, 1998). These values are listed in Table 7-2.

A summary of the project's maximum predicted impact on the Class I area is presented in Table 7-2. As indicated, the predicted maximum impacts are below the EPA significance values for particulate matter (PM), SO_2, and NO_2. Because ISCST3 was used to conservatively estimate the impact of Power Block 2 emissions on the NWA, no further analysis is required for those pollutants.

7.3 Air Toxics Analysis

Concentrations of sulfuric acid mist were modelled with ISCST3 in the same way that SO_2 was modelled. As with SO_2, highest emissions of this pollutant occur while using fuel oil. The predicted maximum 24-hour average concentration of sulfuric acid mist is 0.36 ug/m^3. This is well below the former FDEP ambient reference concentration (ARC) of 2.4 ug/m^3. Therefore, no adverse impacts will occur from emissions of sulfuric acid mist from Power Block 2.

TABLE 7-1

SUMMARY OF SIGNIFICANT IMPACT ANALYSIS CONCENTRATIONS

PSD CLASS II AREAS

Pollutant	Averaging Period	Maximum [1] Predicted Concentration (ug/m^3)	Location [2]		Year	Significance Level (ug/m^3)	Distance to Significance (km)	Significant Impact (Yes/No)
			X (m)	Y (m)				
Carbon Monoxide	1-Hour	345.6	-433	250	1988	2,000	None	No
	8-Hour	114.4	400	-200	1991	500	None	No
Nitrogen Dioxide	Annual	0.36	-492	-87	1990	1	None	No
Sulfur Dioxide	3-Hour	12.7	400	-200	1991	25	None	No
	24-Hour	3.55	400	-200	1991	5	None	No
	Annual	0.02	2500	5000	1990	1	None	No
Particulate Matter (PM_{10}) [3]	24-Hour	2.89	400	-200	1991	5	None	No
	Annual	0.07	-492	-87	1990	1	None	No
Sulfuric Acid Mist	24-Hour	0.36	400	-200	1991	N/A	N/A	N/A

(1) Short-term values are highest values for this analysis.
(2) With respect to zero point of 414.30 km E; 3,073.88 km N.
(3) As a conservative approach, all project emissions of particulate matter were assumed to be in the form of PM_{10}.

N/A = Not applicable

FPC, 1998

TABLE 7-2

SUMMARY OF MAXIMUM MODELED IMPACTS VS.
PSD CLASS I SIGNIFICANCE VALUES

Pollutant	Averaging Period	Highest Modeled Concentration (ug/m^3)	PSD Class I Signif. Level (ug/m^3)	Significance
Sulfur Dioxide (SO_2)	3-Hour	0.79	1.0	NO
	24-Hour	0.17	0.2	NO
	Annual	0.001	0.1	NO
Particulate Matter (PM_{10})	24-Hour	0.07	0.3	NO
	Annual	0.003	0.2	NO
Nitrogen Dioxide (NO_2)	Annual	0.014	0.1	NO

8.0 ADDITIONAL IMPACTS ANALYSIS

8.1 INTRODUCTION

The PSD guidelines indicate that, in addition to demonstrating that the proposed source will neither cause nor contribute to violations of the applicable PSD increments and AAQS, an additional impacts analysis must be conducted for those pollutants subject to PSD review. As indicated in Table 2-5, those pollutants include CO, NO_X, SO_2, PM, VOC (O_3), and sulfuric acid mist. This additional impacts analysis includes an analysis of air quality impacts due to growth induced by the project, an analysis of air quality impacts on soils and vegetation, and an analysis of project impacts on visibility.

As has been demonstrated in Section 7.0 of this application, the proposed project will have an insignificant impact at the NWA, located from 118 to 135 km from the proposed source. In spite of this distance, FPC is providing a general assessment of the impact of Power Block 2 on air quality-related values (AQRV) analysis as a part of this application.

8.2 IMPACTS DUE TO GROWTH

The growth analysis considers air quality impacts due to emissions resulting from the industrial, commercial, and residential growth associated with the project. Only impacts related to permanent growth are considered; emissions from temporary sources and mobile sources are not addressed in the growth analysis. The analysis of socioeconomic effects presented in Chapter 7.0 of the Site Certification Application serves as the basis for this growth analysis.

Up to 500 people will be employed at the Hines Energy Complex site during any one year of the construction phase for Power Block 2, and approximately 4 new permanent jobs will be filled to operate the new facility. It is anticipated that the majority of the construction workers will commute from their current residences, whereas approximately 2 of the 4 new operational employees will migrate into the Polk County area. Based on the average household size of 2.53 persons, a total of 5 persons (workers and their families) are predicted to move into the area as a result of Power Block 2. This will have an insignificant impact on the population of Polk County.

Development of industries supporting the new CC facility are expected to be negligible. Raw materials consumed by the facility (fuels, supplies, etc.) will be delivered to the site in usable form from outside of the region. Further processing, such as water treatment, will be accomplished entirely onsite.

Electricity sales, on the other hand, will be spread out over a large region as part of FPC's generating capacity that will serve to meet increasing residential, commercial, and industrial demand throughout its system, which covers a large portion of the state of Florida.

In summary, there will be little residential growth associated with the FPC project, and there is little potential for new industrial development nearby as a result of the new facility. Impacts resulting from the new development are expected to be small and well-distributed throughout the area.

8.3 VEGETATION, SOILS, AND WILDLIFE ANALYSES

As previously discussed, the predicted maximum impacts from Power Block 2 on the NWA are less than the PSD Class I and Class II significance levels. Therefore, the project will have a negligible impact on the soils, vegetation, wildlife, and visibility of the area surrounding the plant as well as the more distant Class I area. A general discussion of air quality-related values (AQRVs) of the NWA follows.

The U.S. Department of the Interior (National Park Service) in 1978 administratively defined AQRVs to be:

> All those values possessed by an area except those that are not affected by changes in air quality and include all those assets of an area whose vitality, significance, or integrity is dependent in some way upon the air environment. These values include visibility and those scenic, cultural, biological, and recreational resources of an area that are affected by air quality.
>
> Important attributes of an area are those values or assets that make an area significant as a national monument, preserve, or primitive area. They are assets that are to be preserved if the area is to achieve the purposes for which it was set aside.

In a November 1996 report entitled "Air Quality and Air Quality Related Values in Chassahowitzka National Wildlife Refuge and Wilderness Area," the US Fish and Wildlife Service discussed vegetation, soils, wildlife, visibility, and water quality as potential AQRVs in the NWA. Effects from air pollution on visibility have been evaluated in the NWA, but the other potential AQRVs have not been specifically evaluated by the Fish and Wildlife Service for Chassahowitzka. Since specific AQRVs have not been identified for the Chassahowitzka NWA, this AQRV analysis evaluates the effects of air quality on general vegetation types and wildlife found on the Chassahowitzka NWA.

Vegetation type AQRVs and their representative species types have been defined as:

> Marshlands - black needlerush, saw grass, salt grass, and salt marsh cordgrass

Marsh Islands - cabbage palm and eastern red cedar

Estuarine Habitat - black needlerush, salt marsh cordgrass, wax myrtle

Hardwood Swamp - red maple, red bay, sweet bay and cabbage palm

Upland Forests - live oak, scrub oak, longleaf pine, slash pine, wax myrtle and saw palmetto

Mangrove Swamp - red, white and black mangrove

Wildlife AQRVs included: endangered species, waterfowl, marsh and waterbirds, shorebirds, reptiles and mammals.

A screening approach was used which compared the maximum predicted ambient concentration of air pollutants of concern in the Chassahowitzka NWR with effect threshold limits for both vegetation and wildlife as reported in the scientific literature. A literature search was conducted which specifically addressed the effects of air contaminants on plant species reported to occur in the NWR. While the literature search focused on such species as cabbage palm, eastern red cedar, lichens and species of the hardwood swamplands and mangrove forest, no specific citations that addressed these species were found. It was recognized that effect threshold information is not available for all species found in the Chassahowitzka NWR, although studies have been performed on a few of the common species and on other similar species which can be used as models. Maximum concentrations and depositions were predicted using the ISCST model and five years of meteorological data as described in Sections 6.0 and 7.0.

8.3.1 Vegetation

The effects of air contaminants on vegetation occur primarily from sulfur dioxide, nitrogen dioxide, ozone, and particulates. Effects from minor air contaminants such as fluoride, chlorine, hydrogen chloride, ethylene, ammonia, hydrogen sulfide, carbon monoxide, and pesticides have been reported in the literature. However, most of these air contaminants have not resulted in major effects (i.e., crop damage). Some air contaminants, such as ethylene, are widely distributed but, due to low concentrations, do not result in injury to plants. Others such as CO do not cause damage at concentrations normally found under ambient concentrations. There are no predicted fluoride emissions from the proposed project.

Injury to vegetation from exposure to various levels of air contaminants can be termed acute, physiological or chronic. Acute injury occurs as a result of a short-term exposure to a high contaminant concentration and is typically manifested by visible injury symptoms ranging from chlorosis (discoloration) to necrosis (dead areas). Physiological or latent injury occurs as the result of a long-term exposure to contaminant concentrations below that which results in acute injury symptoms, while chronic injury results from repeated exposure to low concentrations over extended periods of time, often without any visible symptoms, but with some effect on the overall growth and productivity of the plant.

Since predicted maximum pollutant concentrations at the NWA are below significance levels, no adverse effects to vegetation will be caused by the proposed project.

8.3.2 Soils

Air contaminants can affect soils through fumigation by gaseous forms, accumulation of compounds transformed from the gaseous state, or by the direct deposition of particulate matter or particulate matter to which certain contaminants are absorbed. Gaseous fumigation of soils does not directly affect the soil but rather the organisms found in the soil. Concentrations several orders of magnitude higher than the predicted values are required before any adverse effects from fumigation are observed. It is more likely that effects on soils and the organisms (plants and animals) found in the soils could occur from the deposition of trace elements over the life of the project. Thus, this analysis of effects on soils specifically addresses the deposition of trace elements and potential pathways for movements into the vegetation.

8.3.2.1 Lead

Lead (Pb) is found naturally occurring in all plants, although it is nonessential for growth (Chapman, 1966; Valkovic, 1975; Gough and Shacklette, 1976). Plants vary in their sensitivity to lead. Many plants tolerate high concentrations of lead, while others exhibit retarded growth at 10 ppm in solution culture (Valkovic, 1975). Orange seedlings grown on soils with lead concentrations ranging from 150-200 ppm did not exhibit adverse effects (Chapman, 1966). Gough et al. (1979) reported that a lead soil concentration of 30 to 100 g/g generally retarded the growth of plants. The negligible amount of lead emissions from Power Block 2 will not contribute to a soil concentration toxic to plants.

8.3.2.2 Mercury

Mercury (Hg) is not an essential element for plant growth. It is typically used as a seed fungicide. In general, Hg is not concentrated in plants grown on soils containing normal levels of Hg. Soil bound Hg is typically not available for plant uptake, although many plants cannot prevent the uptake of gaseous Hg through the roots (Huckabee and Jansen, 1975). Most higher vascular plants are resistant to toxicity from high Hg concentrations even though high concentrations are present in plant tissue. Concentrations of 0.5-50 ppm (HgCl2) were found to inhibit the growth of cauliflower, lettuce, potato, and carrots (Bell and Rickard, 1974). Gough et al. (1979) noted apparently healthy spanish moss plants with a mercury content of 0.5 mg/kg. The extremely small amount of mercury emissions from the proposed power block will not contribute to concentrations toxic to plants.

8.3.3 <u>Wildlife</u>

Compared with other threats to wildlife, such as pesticides, the toxicological relationships between air pollution and effects on wildlife are not well understood (Newman and Schreiber, 1988). The limited understanding is based primarily on reports of symptoms observed in the field and on information extrapolated from laboratory studies. Information on controlled wildlife studies is limited in the scientific literature. Most studies report symptoms of various air pollutants but do not provide toxicity levels. Those studies that do provide toxicity levels are limited to four air contaminants, SO_2, NO_2, O_3, and particulates.

Since the predicted maximum pollutant impacts are less than Class I significance levels, no adverse impacts to wildlife will occur from the proposed Power Block 2 emissions.

In addition to the impacts on wildlife from the primary pollutants, the Fish and Wildlife Service is concerned about the effects on wildlife resulting from acid deposition (FWS, 1992). Existing acid deposition conditions in Florida were investigated during the five year Florida Acid Deposition Study (ESE, 1986 and 1987) and the two year follow-up program called the Florida Acid Deposition Monitoring Program (ESE, 1988 and 1989). The data collected in these programs indicate that Florida precipitation is only about two-thirds as acidic as precipitation across the southeastern United States and less than half as acidic as precipitation in the midwestern and northeastern United States (ESE, 1988). There is no evidence of a temporal trend in precipitation acidity since the late 1970s (ESE, 1989). The Clean Air Act Amendments of 1990 require significant reductions in SO_2 and NO_2 emissions from existing uncontrolled utility plants nationwide and some of these reductions will occur at plants in the general vicinity of the NWA. These emission reductions will undoubtedly improve on the already good estimated acid deposition conditions in the NWR.

Due to the small emission increases that will be caused by the proposed project and the resulting insignificant concentrations, increase, if any in acid deposition will be negligible.

8.4 VISIBILITY IMPACTS

A visibility analysis was performed for both Power Blocks 1 and 2 in the 1992 PSD application. No adverse increase in visibility degradation was predicted in that analysis. Since the maximum predicted SO_2 and NOx impacts from Power Block 2 are predicted to be less than the Class I significance levels, there will be little, if any incremental impact to the area's visibility. This approach was confirmed in conversations with FDEP staff.

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PSD PERMIT APPLICATION

FOR

FLORIDA POWER CORPORATION
HINES ENERGY COMPLEX
POWER BLOCK 2

January 1999

Florida Power Corporation
One Power Plaza
263 13th Ave. South
St. Petersburg, Florida 33701

10.1.5 Prevention of Significant Deterioration Permit Application

Following is a copy of the Prevention of Significant Deterioration (PSD) permit application for Power Block 2 submitted to the DEP pursuant to requirements of the Federal Clean Air Act.

APPLICATION FORMS

Department of

Environmental Protection

DIVISION OF AIR RESOURCES MANAGEMENT

APPLICATION FOR AIR PERMIT - LONG FORM

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

I. APPLICATION INFORMATION

This section of the Application for Air Permit form identifies the facility and provides general information on the scope and purpose of this application. This section also includes information on the owner or authorized representative of the facility (or the responsible official in the case of a Title V source) and the necessary statements for the applicant and professional engineer, where required, to sign and date for formal submittal of the Application for Air Permit to the Department. If the application form is submitted to the Department using ELSA, this section of the Application for Air Permit must also be submitted in hard-copy.

Identification of Facility Addressed in This Application

Enter the name of the corporation, business, governmental entity, or individual that has ownership or control of the facility; the facility site name, if any; and the facility's physical location. If known, also enter the facility identification number.

1. Facility Owner/Company Name: Florida Power Corporation	
2. Site Name: Hines Energy Complex	
3. Facility Identification Number: [x] Unknown	
4. Facility Location Information: Street Address or Other Locator: County Rd 555;2.5m S of CR 640 City: Bartow County: Polk Zip Code: 33830	
5. Relocatable Facility? [ ] Yes [x] No	6. Existing Permitted Facility? [x] Yes [ ] No

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	
2. Permit Number:	
3. PSD Number (if applicable):	
4. Siting Number (if applicable):	

Owner/Authorized Representative or Responsible Official

1. Name and Title of Owner/Authorized Representative or Responsible Official:

   W. Jeffrey Pardue, Dir. Environmental Services Dept.

2. Owner/Authorized Representative or Responsible Official Mailing Address:

Organization/Firm: Florida Power Corporation
Street Address: One Power Plaza,263-13th Ave S
City: St. Petersburg State: FL Zip Code: 33701-5511

3. Owner/Authorized Representative or Responsible Official Telephone Numbers:

Telephone: (727) 826-4301 Fax: (727) 826-4216

4. Owner/Authorized Representative or Responsible Official Statement:

I, the undersigned, am the owner or authorized representative of the non-Title V source addressed in this Application for Air Permit or the responsible official, as defined in Rule 62-210.200, F.A.C., 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: [signature] Date: 1/5/99

* Attach letter of authorization if not currently on file.

Scope of Application

This Application for Air Permit addresses the following emissions unit(s) at the facility. An Emissions Unit Information Section (a Section III of the form) must be included for each emissions unit listed.

Emissions Unit ID		Description of Emissions Unit	Permit Type
Unit #	Unit ID		
1R	---	CT-1; Power Block 2	AC1A
2R	---	CT-2; Power Block 2	AC1A

See individual Emissions Unit (EU) sections for more detailed descriptions.
Multiple EU IDs indicated with an asterisk (*). Regulated EU indicated with an "R".

Purpose of Application and Category

Check one (except as otherwise indicated):

Category I: All Air Operation Permit Applications Subject to Processing Under Chapter 62-213, F.A.C.

This Application for Air Permit is submitted to obtain:

[ ] Initial air operation permit under Chapter 62-213, F.A.C., for an existing facility which is classified as a Title V source.

[ ] Initial air operation permit under Chapter 62-213, F.A.C., 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: ______________________

[ ] Air operation permit renewal under Chapter 62-213, F.A.C., for a Title V source.

Operation permit to be renewed: ______________________

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

Current construction permit number: ______________________

Operation permit to be renewed: ______________________

[ ] Air operation permit revision or administrative correction for a Title V source to address one or more proposed new or modified emissions units and to be processed concurrently with the air construction permit application. Also check Category III.

Operation permit to be revised/corrected: ______________________

____

[ ] Air operation permit revision for a Title V source 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 to be revised: ______________________

Reason for revision: ______________________

____

Category II: All Air Construction Permit Applications Subject to Processing Under Rule 62-210.300(2)(b),F.A.C.

This Application for Air Permit is submitted to obtain:

[ ] Initial air operation permit under Rule 62-210.300(2)(b), F.A.C., for an existing facility seeking classification as a synthetic non-Title V source.

Current operation/construction permit number(s): ______________________

____

[ ] Renewal air operation permit under Rule 62-210.300(2)(b), F.A.C., for a synthetic non-Title V source.

Operation permit to be renewed: ______________________

[ ] Air operation permit revision for a synthetic non-Title V source. Give reason for revision; e.g.; to address one or more newly constructed or modified emissions units.

Operation permit to be revised: ______________________

Reason for revision: ______________________

____

Category III: All Air Construction Permit Applications for All Facilities and Emissions Units.

This Application for Air Permit is submitted to obtain:

[x] Air construction permit to construct or modify one or more emissions units within a facility (including any facility classified as a Title V source).

Current operation permit number(s), if any: ______________________

____

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

Current operation permit number(s): ______________________

____

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

Application Processing Fee

Check one:

[ ] Attached - Amount: ________________ [x] Not Applicable.

Construction/Modification Information

1. Description of Proposed Project or Alterations: Power Block 2 consists of two nominal 165 MW Westinghouse 501F combustion turbines (CTs), two unfired heat recovery steam generators (HRSGs), and one 170 MW steam turbine; nominal rating of 500 MW combined cycle unit. See PSD Application. Fee included with Site Certification Application.
2. Projected or Actual Date of Commencement of Construction : 1 Nov 1999
3. Projected Date of Completion of Construction : 1 Jul 2001

Professional Engineer Certification

1. Professional Engineer Name: Kennard F. Kosky Registration Number: 14996
2. Professional Engineer Mailing Address: Organization/Firm: Golder Associates Inc. Street Address: 6241 NW 23rd Street; Suite 500 City: Gainesville State: FL Zip Code: 32653
3. Professional Engineer Telephone Numbers: Telephone: (352) 336-5600 Fax: (352) 336-6603

4. Professional Engineer's 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.

Konrad F. Kosky — 12/31/98

Signature — Date

(seal) 7&4

* Attach any exception to certification statement.

Application Contact

1. Name and Title of Application Contact:
   Scott Osbourn, Senior Environmental Specialist

2. Application Contact Mailing Address:

   Organization/Firm: Florida Power Corporation
   Street Address: One Power Plaza,263-13th Ave S
   City: St. Petersburg State: FL Zip Code: 33701-5511

3. Application Contact Telephone Numbers:

   Telephone: (727) 826-4258 Fax: (727) 826-4216

Application Comment

This application has been submitted and will be reviewed within the Florida Power Plant Siting Act (PPSA). See PSD Application. Power Block 1 has permit PA-92-33; PSD-FL-195A.

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates:
   Zone: 17 East (km): 414.4 North (km): 3073.9

2. Facility Latitude/Longitude:
   Latitude (DD/MM/SS): 27 / 47 / 19 Longitude: (DD/MM/SS): 81 / 52 / 10

3. Governmental Facility Code:	4. Facility Status Code:	5. Facility Major Group SIC Code:	6. Facility SIC(s):
0	C	49	4911

7. Facility Comment (limit to 500 characters):

Operation of Power Block 1 has recently begun. Power Block 1 is a nominal 500 MW combined cycle unit consisting of 2 CTs, 2 HRSG's and 1 steam turbine. The CTs fire natural gas with distillate oil as backup. The HRSGs are unfired. This application is for the addition of Power Block 2, a nominal 500 MW conbined cycle application. See PSD Application.

Facility Contact

1. Name and Title of Facility Contact:
   David Sorrick, Plant Manager

2. Facility Contact Mailing Address:
   Organization/Firm: Hines Energy Complex
   Street Address: 7700 County Road 555
   City: Bartow State: FL Zip Code: 33830

3. Facility Contact Telephone Numbers:
   Telephone: (941) 519-6201 Fax: (941) 519-6210

Facility Regulatory Classifications

1. Small Business Stationary Source? [ ] Yes	[x] No	[ ] Unknown
2. Title V Source? [x] Yes	[ ] No	
3. Synthetic Non-Title V Source? [ ] Yes	[x] No	
4. Major Source of Pollutants Other than Hazardous Air Pollutants (HAPs)? [x] Yes	[ ] No	
5. Synthetic Minor Source of Pollutants Other than HAPs? [ ] Yes	[x] No	
6. Major Source of Hazardous Air Pollutants (HAPs)? [ ] Yes	[x] No	
7. Synthetic Minor Source of HAPs? [ ] Yes	[x] No	
8. One or More Emissions Units Subject to NSPS? [x] Yes	[ ] No	
9. One or More Emissions Units Subject to NESHAP? [ ] Yes	[x] No	
10. Title V Source by EPA Designation? [ ] Yes	[x] No	
11. Facility Regulatory Classifications Comment (limit to 200 characters): **Applicable NSPS is 40 CFR Part 60; Subpart GG.**		

B. FACILITY REGULATIONS

Rule Applicability Analysis (Required for Category II applications and Category III applications involving non Title-V sources. See Instructions.)

List of Applicable Regulations (Required for Category I applications and Category III applications involving Title-V sources. See Instructions.)

62-212.400, F.A.C. See PSD Application

C. FACILITY POLLUTANTS

Facility Pollutant Information

1. Pollutant Emitted		2. Pollutant Classification
PM	Particulate Matter - Total	A
SO2	Sulfur Dioxide	A
NOx	Nitrogen Oxides	A
CO	Carbon Monoxide	A
VOC	Volatile Organic Compounds	A
SAM	Sulfuric Acid Mist	A

D. FACILITY POLLUTANT DETAIL INFORMATION

Facility Pollutant Detail Information:

1. Pollutant Emitted:		
2. Requested Emissions Cap:	(lb/hr)	(tons/yr)
3. Basis for Emissions Cap Code:		
4. Facility Pollutant Comment (limit to 400 characters):		

Facility Pollutant Detail Information:

1. Pollutant Emitted:		
2. Requested Emissions Cap:	(lb/hr)	(tons/yr)
3. Basis for Emissions Cap Code:		
4. Facility Pollutant Comment (limit to 400 characters):		

E. FACILITY SUPPLEMENTAL INFORMATION

Supplemental Requirements for All Applications

1. Area Map Showing Facility Location:
   [x] Attached, Document ID: Fig. 1-1; PSD
   [ ] Not Applicable [ ] Waiver Requested

2. Facility Plot Plan:
   [x] Attached, Document ID: Fig. 2-1; PSD
   [ ] Not Applicable [ ] Waiver Requested

3. Process Flow Diagram(s):
   [x] Attached, Document ID(s). Fig. 2-2; PSD
   [ ] Not Applicable [ ] Waiver Requested

4. Precautions to Prevent Emissions of Unconfined Particulate Matter:
   [x] Attached, Document ID: PSD Appl.
   [ ] 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 Appl.
   [ ] Not Applicable

Additional Supplemental Requirements for Category I Applications Only

7. List of Proposed Exempt Activities:
   [ ] Attached, Document ID: ______
   [ ] Not Applicable

8. List of Equipment/Activities Regulated under Title VI:
   [ ] Attached, Document ID: ______
   [ ] Equipment/Activities On site but Not Required to be Individually Listed
   [ ] Not Applicable

9. Alternative Methods of Operation:
   [ ] Attached, Document ID: ______
   [ ] Not Applicable

10. Alternative Modes of Operation (Emissions Trading):
    [ ] Attached, Document ID: ______
    [ ] Not Applicable

11. Identification of Additional Applicable Requirements: [ ] Attached, Document ID: ______________ [ ] Not Applicable
12. Compliance Assurance Monitoring Plan: [ ] Attached, Document ID: ______________ [ ] Not Applicable
13. Risk Management Plan Verification: [ ] Plan Submitted to Implementing Agency - Verification Attached Document ID: ______________ [ ] Plan to be Submitted to Implementing Agency by Required Date [ ] Not Applicable
14. Compliance Report and Plan [ ] Attached, Document ID: ______________ [ ] Not Applicable
15. Compliance Statement (Hard-copy Required) [ ] Attached, Document ID: ______________ [ ] Not Applicable

III. EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through L 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. Some of the subsections comprising the Emissions Unit Information Section of the form are intended for regulated emissions units only. Others are intended for both regulated and unregulated emissions units. Each subsection is appropriately marked.

A. TYPE OF EMISSIONS UNIT
(Regulated and Unregulated Emissions Units)

Type of Emissions Unit Addressed in This Section

1. 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.

2. Single Process, Group of Processes, or Fugitive Only? 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.

B. GENERAL EMISSIONS UNIT INFORMATION
(Regulated and Unregulated Emissions Units)

Emissions Unit Description and Status

1. Description of Emissions Unit Addressed in This Section (limit to 60 characters): CT-1; Power Block 2		
2. Emissions Unit Identification Number: [ ] No Corresponding ID [X] Unknown		
3. Emissions Unit Status Code: C	4. Acid Rain Unit? [X] Yes [ ] No	5. Emissions Unit Major Group SIC Code: 49
6. Emissions Unit Comment (limit to 500 characters): Westinghouse 501 F combustion turbine firing natural gas with distillate oil back-up.		

Emissions Unit Control Equipment Information

A.

1. Description (limit to 200 characters): Dry Low NOx combustion-natural gas firing
2. Control Device or Method Code: 25

B.

1. Description (limit to 200 characters): Selective Catalytic Reduction (SCR) - natural gas firing
2. Control Device or Method Code: 65

C.

1. Description (limit to 200 characters): Water Injection - distillate oil firing
2. Control Device or Method Code: 28

C. EMISSIONS UNIT DETAIL INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Details

1. Initial Startup Date:	
2. Long-term Reserve Shutdown Date:	
3. Package Unit: Manufacturer: Westinghouse	Model Number: 501F
4. Generator Nameplate Rating:	165 MW
5. Incinerator Information: Dwell Temperature: Dwell Time: Incinerator Afterburner Temperature:	 °F seconds °F

Emissions Unit Operating Capacity

1. Maximum Heat Input Rate:	1,822	mmBtu/hr
2. Maximum Incineration Rate:	lbs/hr	tons/day
3. Maximum Process or Throughput Rate:		
4. Maximum Production Rate:		
5. Operating Capacity Comment (limit to 200 characters): **Heat input is HHV; heat input at 59 degree F turbine inlet temperature; MW nominal rating.**		

Emissions Unit Operating Schedule

1. Requested Maximum Operating Schedule:		
	hours/day	days/week
	weeks/yr	8,760 hours/yr

D. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

Rule Applicability Analysis (Required for Category II Applications and Category III applications involving non Title-V sources. See Instructions.)

List of Applicable Regulations (Required for Category I applications and Category III applications involving Title-V sources. See Instructions.)

See Attachment PB2-EU1-D
See PSD Application

ATTACHMENT PB2-EU1-D

APPLICABLE REQUIREMENTS LISTING

ATTACHMENT PB2-EU1-D

Applicable Requirements Listing

EMISSION UNIT ID: EU1

FDEP Rules:

Air Pollution Control-General Provisions:

62-204.800(7)(b)37. (State Only)	- NSPS Subpart GG
62-204.800(7)(c) (State Only)	- NSPS authority
62-204.800(7)(d)(State Only)	- NSPS General Provisions
62-204.800(12) (State Only)	- Acid Rain Program
62-204.800(13) (State Only)	- Allowances
62-204.800(14) (State Only)	- Acid Rain Program Monitoring
62-204.800(16) (State Only)	- Excess Emissions (Potentially applicable over term of permit)

Stationary Sources-General:

62-210.650	- Circumvention; EUs with control device
62-210.700(1)	- Excess Emissions;
62-210.700(4)	- Excess Emissions; poor maintenance
62-210.700(6)	- Excess Emissions; notification

Acid Rain:

62-214.300	- All Acid Rain Units (Applicability)
62-214.320(1)(a),(2)	- All Acid Rain Units (Application Shield)
62-214.330(1)(a)1.	- Compliance Options (if 214.430)
62-214.340	- Exemptions (new units, retired units)
62-214.350(2);(3);(6)	- All Acid Rain Units (Certification)
62-214.370	- All Acid Rain Units (Revisions; correction; potentially applicable if a need arises)
62-214.430	- All Acid Rain Units (Compliance Options-if required)

Stationary Sources-Emission Standards:

62-296.320(4)(b)(State Only)	- CTs/Diesel Units

Stationary Sources-Emission Monitoring (where stack test is required):

62-297.310(1)	- All Units (Test Runs-Mass Emission)
62-297.310(2)(b)	- All Units (Operating Rate; other than CTs;no CT)
62-297.310(3)	- All Units (Calculation of Emission)
62-297.310(4)(a)	- All Units (Applicable Test Procedures;Sampling time)
62-297.310(4)(b)	- All Units (Sample Volume)
62-297.310(4)(c)	- All Units (Required Flow Rate Range-PM/H2SO4/F)
62-297.310(4)(d)	- All Units (Calibration)
62-297.310(4)(e)	- All Units (EPA Method 5-only)
62-297.310(5)	- All Units (Determination of Process Variables)

62-297.310(6)(a)	- All Units (Permanent Test Facilities-general)
62-297.310(6)(c)	- All Units (Sampling Ports)
62-297.310(6)(d)	- All Units (Work Platforms)
62-297.310(6)(e)	- All Units (Access)
62-297.310(6)(f)	- All Units (Electrical Power)
62-297.310(6)(g)	- All Units (Equipment Support)
62-297.310(7)(a)1.	- Applies mainly to CTs/Diesels
62-297.310(7)(a)2.	- FFSG excess emissions
62-297.310(7)(a)3.	- Permit Renewal Test Required
62-297.310(7)(a)4.a	- Annual Test
62-297.310(7)(a)5.	- PM exemption if <400 hrs/yr
62-297.310(7)(a)6.	- PM FFSG semi annual test required if >200 hrs/yr
62-297.310(7)(a)7.	- PM quarterly monitoring if >100 hrs/yr
62-297.310(7)(a)9.	- FDEP Notification - 15 days
62-297.310(7)(c)	- Waiver of Compliance Tests (Fuel Sampling)
62-297.310(8)	- Test Reports

Federal Rules:

NSPS Subpart GG:

40 CFR 60.332(a)(1)	- NOx for Electric Utility CTs
40 CFR 60.332(a)(3)	- NOx for Electric Utility CTs
40 CFR 60.333	- SO2 limits
40 CFR 60.334	- Monitoring of Operations (Custom Monitoring for Gas)
40 CFR 60.335	- Test Methods

NSPS General Requirements:

40 CFR 60.7(a)(1)	- Notification of Construction
40 CFR 60.7(a)(2)	- Notification of Initial Start-Up
40 CFR 60.7(a)(3)	- Notification of Actual Start-Up
40 CFR 60.7(a)(4)	- Notification and Recordkeeping (Physical/Operational Cycle)
40 CFR 60.7(a)(5)	- Notification of CEM Demonstration
40 CFR 60.7(b) (startup/shutdown/malfunction)	- Notification and Recordkeeping
40 CFR 60.7(c) (startup/shutdown/malfunction)	- Notification and Recordkeeping
40 CFR 60.7(d) (startup/shutdown/malfunction)	- Notification and Recordkeeping
40 CFR 60.7(f)	- Notification and Recordkeeping (maintain records-2 yrs)
40 CFR 60.8(a)	- Performance Test Requirements
40 CFR 60.8(b)	- Performance Test Notification
40 CFR 60.8(c)	- Performance Tests (representative conditions)
40 CFR 60.8(e)	- Provide Stack Sampling Facilities
40 CFR 60.8(f)	- Test Runs
40 CFR 60.11(a)	- Compliance (ref. S. 60.8 or Subpart; other than opacity)
40 CFR 60.11(b)	- Compliance (opacity determined EPA Method 9)

40 CFR 60.11(c) startup/shutdown/malfunction)	- Compliance (opacity; excludes
40 CFR 60.11(d)	- Compliance (maintain air pollution control equip.)
40 CFR 60.11(e)(2)	- Compliance (opacity; ref. S. 60.8)
40 CFR 60.12	- Circumvention
40 CFR 60.13(a)	- Monitoring (Appendix B; Appendix F)
40 CFR 60.13(c)	- Monitoring (Opacity COMS)
40 CFR 60.13(d)(1)	- Monitoring (CEMS; span, drift, etc.)
40 CFR 60.13(d)(2)	- Monitoring (COMS; span, system check)
40 CFR 60.13(e)	- Monitoring (frequency of operation)
40 CFR 60.13(f)	- Monitoring (frequency of operation)
40 CFR 60.13(h)	- Monitoring (COMS; data requirements)

Acid Rain-Permits:

40 CFR 72.9(a)	- Permit Requirements
40 CFR 72.9(b)	- Monitoring Requirements
40 CFR 72.9(c)(1)	- SO2 Allowances-hold allowances
40 CFR 72.9(c)(2)	- SO2 Allowances-violation
40 CFR 72.9(c)(3)(iii)	- SO2 Allowances-Phase II Units (listed)
40 CFR 72.9(c)(4)	- SO2 Allowances-allowances held in ATS
40 CFR 72.9(c)(5)	- SO2 Allowances-no deduction for 72.9(c)(1)(i)
40 CFR 72.9(d)	- NOx Requirements
40 CFR 72.9(e)	- Excess Emission Requirements
40 CFR 72.9(f)	- Recordkeeping and Reporting
40 CFR 72.9(g)	- Liability
40 CFR 72.20(a)	- Designated Representative; required
40 CFR 72.20(b)	- Designated Representative; legally binding
40 CFR 72.20(c)	- Designated Representative; certification requirements
40 CFR 72.21	- Submissions
40 CFR 72.22	- Alternate Designated Representative
40 CFR 72.23	- Changing representatives; owners
40 CFR 72.24	- Certificate of representation
40 CFR 72.30(a)	- Requirements to Apply (operate)
40 CFR 72.30(b)(2)	- Requirements to Apply (Phase II-Complete)
40 CFR 72.30(c)	- Requirements to Apply (reapply before expiration)
40 CFR 72.30(d)	- Requirements to Apply (submittal requirements)
40 CFR 72.31	- Information Requirements; Acid Rain Applications
40 CFR 72.32	- Permit Application Shield
40 CFR 72.33(b)	- Dispatch System ID;unit/system ID
40 CFR 72.33(c)	- Dispatch System ID;ID requirements
40 CFR 72.33(d)	- Dispatch System ID;ID change
40 CFR 72.40(a)	- General; compliance plan
40 CFR 72.40(b)	- General; multi-unit compliance options
40 CFR 72.40(c)	- General; conditional approval
40 CFR 72.40(d)	- General; termination of compliance options
40 CFR 72.51	- Permit Shield
40 CFR 72.90	- Annual Compliance Certification

Allowances:

40 CFR 73.33(a),(c)	- Authorized account representative
40 CFR 73.35(c)(1)	- Compliance: ID of allowances by serial number

Monitoring Part 75:

40 CFR 75.4	- Compliance Dates;
40 CFR 75.5	- Prohibitions
40 CFR 75.10(a)(1)	- Primary Measurement; SO2;
40 CFR 75.10(a)(2)	- Primary Measurement; NOx;
40 CFR 75.10(a)(3)(iii)	- Primary Measurement; CO2; O2 monitor
40 CFR 75.10(b)	- Primary Measurement; Performance Requirements
40 CFR 75.10(c)	- Primary Measurement; Heat Input; Appendix F
40 CFR 75.10(e)	- Primary Measurement; Optional Backup Monitor
40 CFR 75.10(f)	- Primary Measurement; Minimum Measurement
40 CFR 75.10(g)	- Primary Measurement; Minimum Recording
40 CFR 75.11(d)	- SO2 Monitoring; Gas- and Oil-fired units
40 CFR 75.11(e)	- SO2 Monitoring; Gaseous firing
40 CFR 75.12(a)	- NOx Monitoring; Coal; Non-peaking oil/gas units
40 CFR 75.12(b)	- NOx Monitoring; Determination of NOx emission rate; Appendix F
40 CFR 75.13(b)	- CO2 Monitoring; Appendix G
40 CFR 75.13(c)	- CO2 Monitoring; Appendix F
40 CFR 75.14(c)	- Opacity Monitoring; Gas units; exemption
40 CFR 75.20(a) Certification	- Initial Certification Approval Process; Loss of
40 CFR 75.20(b)	- Recertification Procedures (if recertification necessary)
40 CFR 75.20(c)	- Certification Procedures (if recertification necessary)
40 CFR 75.20(d)	- Recertification Backup/portable monitor
40 CFR 75.20(f)	- Alternate Monitoring system
40 CFR 75.21(a) 12/31/96)	- QA/QC; CEMS; Appendix B (Suspended 7/17/95-
40 CFR 75.21(c)	- QA/QC; Calibration Gases
40 CFR 75.21(d)	- QA/QC; Notification of RATA
40 CFR 75.21(e)	- QA/QC; Audits
40 CFR 75.21(f)	- QA/QC; CEMS (Effective 7/17/96-12/31/96)
40 CFR 75.22	- Reference Methods
40 CFR 75.24	- Out-of-Control Periods; CEMS
40 CFR 75.30(a)(3)	- General Missing Data Procedures; NOx
40 CFR 75.30(a)(4)	- General Missing Data Procedures; SO2
40 CFR 75.30(b) monitor	- General Missing Data Procedures; certified backup
40 CFR 75.30(c) monitor	- General Missing Data Procedures; certified backup
40 CFR 75.30(d)	- General Missing Data Procedures; SO2 (optional before 1/1/97)
40 CFR 75.30(e)	- General Missing Data Procedures; bypass/multiple stacks
40 CFR 75.31	- Initial Missing Data Procedures (new/re-certified CMS)

40 CFR 75.32	- Monitoring Data Availability for Missing Data
40 CFR 75.33	- Standard Missing Data Procedures
40 CFR 75.36	- Missing Data for Heat Input
40 CFR 75.40	- Alternate Monitoring Systems-General
40 CFR 75.41	- Alternate Monitoring Systems-Precision Criteria
40 CFR 75.42	- Alternate Monitoring Systems-Reliability Criteria
40 CFR 75.43	- Alternate Monitoring Systems-Accessability Criteria
40 CFR 75.44	- Alternate Monitoring Systems-Timeliness Criteria
40 CFR 75.45	- Alternate Monitoring Systems-Daily QA
40 CFR 75.46	- Alternate Monitoring Systems-Missing data
40 CFR 75.47	- Alternate Monitoring Systems-Criteria for Class
40 CFR 75.48	- Alternate Monitoring Systems-Petition
40 CFR 75.53	- Monitoring Plan ; revisions
40 CFR 75.54(a)	- Recordkeeping-general
40 CFR 75.54(b)	- Recordkeeping-operating parameter
40 CFR 75.54(c)	- Recordkeeping-SO2
40 CFR 75.54(d)	- Recordkeeping-NOx
40 CFR 75.54(e)	- Recordkeeping-CO2
40 CFR 75.54(f)	- Recordkeeping-Opacity
40 CFR 75.55(c)	- General Recordkeeping (Specific Situations)
40 CFR 75.55(e)	- General Recordkeeping (Specific Situations)
40 CFR 75.56	- Certification; QA/QC Provisions
40 CFR 75.60	- Reporting Requirements-General
40 CFR 75.61	- Reporting Requirements-Notification cert/recertification
40 CFR 75.62	- Reporting Requirements-Monitoring Plan
40 CFR 75.63	- Reporting Requirements-Certification/Recertification
40 CFR 75.64(a)	- Reporting Requirements-Quarterly reports; submission
40 CFR 75.64(b) statement	- Reporting Requirements-Quarterly reports; DR
40 CFR 75.64(c)	- Rep. Req.; Quarterly reports; Compliance Certification
40 CFR 75.64(d)	- Rep. Req.; Quarterly reports; Electronic format
40 CFR 75.66	- Petitions to the Administrator (if required)
Appendix A-1	- Installation and Measurement Locations
Appendix A-2.	- Equipment Specifications
Appendix A-3.	- Performance Specifications
Appendix A-4.	- Data Handling and Acquisition Systems
Appendix A-5.	- Calibration Gases
Appendix A-6.	- Certification Tests and Procedures
Appendix A-7.	- Calculations
Appendix B	- QA/QC Procedures
Appendix C-1.	- Missing Data; SO2/NOx for controlled sources
Appendix C-2.	- Missing Data; Load-Based Procedure; NOx & flow
Appendix D	- Optional SO2; Oil-/gas-fired units
Appendix F	- Conversion Procedures
Appendix H	- Traceability Protocol

Acid Rain Program-Excess Emissions (these are future requirements):

40 CFR 77.3	- Offset Plans (future)

40 CFR 77.5(b)	- Deductions of Allowances (future)
40 CFR 77.6	- Excess Emissions Penalties (SO2 and NOx;future)

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

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: Fig 2-1	
2. Emission Point Type Code: [x] 1 [ ] 2 [ ] 3 [ ] 4	
3. Descriptions of Emissions Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point): **Exhausts through a single stack.**	
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:	
5. Discharge Type Code: [ ] D [ ] F [ ] H [ ] P [ ] R [x] V [ ] W	
6. Stack Height:	125 feet
7. Exit Diameter:	19 feet
8. Exit Temperature:	206 °F

9. Actual Volumetric Flow Rate:	1,035,668 acfm
10. Percent Water Vapor:	%
11. Maximum Dry Standard Flow Rate:	dscfm
12. Nonstack Emission Point Height:	feet
13. Emission Point UTM Coordinates: Zone: 17 East (km): 414.4 North (km): 3073.9	
14. Emission Point Comment (limit to 200 characters): **Temperature and flow for natural gas at 59 degrees turbine inlet; See Tables 2-1 and 2-2 in PSD application.**	

F. SEGMENT (PROCESS/FUEL) INFORMATION
(Regulated and Unregulated Emissions Units)

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) (limit to 500 characters):

   Natural Gas

2. Source Classification Code (SCC):

   2-01-002-01

3. SCC Units:

   Million Cubic Feet

4. Maximum Hourly Rate: 1.85	5. Maximum Annual Rate: 15,201

6. Estimated Annual Activity Factor:

7. Maximum Percent Sulfur:	8. Maximum Percent Ash:

9. Million Btu per SCC Unit:

   1,050

10. Segment Comment (limit to 200 characters):

    Based on 1,050 BTU/CF (HHV); maximum hourly at 32 degrees F; annual at 59 degrees F; turbine inlet temperatures.

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) (limit to 500 characters): Distillate Fuel Oil	
2. Source Classification Code (SCC): 2-01-001-01	
3. SCC Units: 1,000 Gallons Used	
4. Maximum Hourly Rate: 15.1	5. Maximum Annual Rate: 6,881
6. Estimated Annual Activity Factor:	
7. Maximum Percent Sulfur: 0.05	8. Maximum Percent Ash:
9. Million Btu per SCC Unit: 129	
10. Segment Comment (limit to 200 characters): BTU based on HHV of 129 MMBtu/1,000 gallons. Aggregate fuel usage of 13,762,806 gallons per year requested for Power Block 2.	

G. EMISSIONS UNIT POLLUTANTS
(Regulated and Unregulated Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM			EL
SO2			EL
NOx	026	065	EL
CO			EL
VOC			EL
SAM			El

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: PM
2. Total Percent Efficiency of Control: %
3. Potential Emissions: 46 lb/hour 49 tons/year
4. Synthetically Limited? [ ] Yes [X] No
5. Range of Estimated Fugitive/Other Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/yr
6. Emission Factor: Reference: Westinghouse, 1998
7. Emissions Method Code: [ ] 0 [ ] 1 [X] 2 [ ] 3 [ ] 4 [ ] 5
8. Calculation of Emissions (limit to 600 characters): See Section 2.0 in PSD Application
9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters): Max lb/hr for oil firing at 22 degrees F turbine inlet; TPY at 59 degree F turbine inlet with 8,260 hrs/yr-gas; equivalent of 500 hrs/yr/CT-oil.

Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code: OTHER
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 10 percent Opacity
4. Equivalent Allowable Emissions: 9.8 lb/hour 40.7 tons/year
5. Method of Compliance (limit to 60 characters): EPA Method 9
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): Gas Firing: lb/hr at 32 degree F turbine inlet; TPY for 8,760 hrs/yr at 59 degree F turbine inlet.

B.

1. Basis for Allowable Emissions Code: OTHER
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 20 percent Opacity
4. Equivalent Allowable Emissions: 46 lb/hour 11.5 tons/year
5. Method of Compliance (limit to 60 characters): EPA Method 9
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): Oil firing: lb/hr at 22 degree F turbine inlet; TPY equivalent of 500 hrs/yr/CT-oil at 59 degrees F turbine inlet.

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: SO2

2. Total Percent Efficiency of Control: %

3. Potential Emissions: 104 lb/hour 46.5 tons/year

4. Synthetically Limited? [ ] Yes [x] No

5. Range of Estimated Fugitive/Other Emissions:

   [ ] 1 [ ] 2 [ ] 3 ________ to ________ tons/yr

6. Emission Factor:

   Reference: Westinghouse, 1998

7. Emissions Method Code:

   [ ] 0 [ ] 1 [x] 2 [ ] 3 [ ] 4 [ ] 5

8. Calculation of Emissions (limit to 600 characters):

   See Section 2.0 in PSD Application

9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters):

   Max lb/hr for oil firing at 22 degree F turbine inlet; TPY at 59 degree F turbine inlet; TPY at 59 degree F turbine inlet with 8,260 hrs/yr-gas; equivalent of 500 hrs/yr/CT-oil.

Emissions Unit Information Section 1 **of** 2
Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code: OTHER		
2. Future Effective Date of Allowable Emissions:		
3. Requested Allowable Emissions and Units: Pipeline Gas		
4. Equivalent Allowable Emissions:	**6** lb/hour	**24.1** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel Sampling - Vendor**		
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): **Gas Firing: lb/hr at 32 degree F turbine inlet; TPY for 8,760 hrs/yr at 59 degree F turbine inlet.**		

B.

1. Basis for Allowable Emissions Code: OTHER		
2. Future Effective Date of Allowable Emissions:		
3. Requested Allowable Emissions and Units: **0.05 % Sulfur Oil**		
4. Equivalent Allowable Emissions:	**104** lb/hour	**23.75** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel Sampling - Vendor**		
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): **Oil Firing: lb/hr at 22 degree F turbine inlet; TPY equivalent of 500 hrs/yr/CT-oil at 59 degrees F turbine inlet.**		

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: NOx

2. Total Percent Efficiency of Control: %

3. Potential Emissions: 332 lb/hour 249.5 tons/year

4. Synthetically Limited? [ ] Yes [x] No

5. Range of Estimated Fugitive/Other Emissions:

   [ ] 1 [ ] 2 [ ] 3 ________ to ________ tons/yr

6. Emission Factor:

   Reference: Westinghouse, 1998

7. Emissions Method Code:

   [ ] 0 [ ] 1 [x] 2 [ ] 3 [ ] 4 [ ] 5

8. Calculation of Emissions (limit to 600 characters):

   Maximum lb/hour based on oil-firing. Does not include provision for fuel-bound nitrogen (FBN). An allowance up to 0.03 percent FBN is requested. See Section 2.0 in PSD Application.

9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters):

   Max lb/hr for oil firing at 22 degree F turbine inlet; TPY at 59 degree F turbine inlet with 8,260 hrs/yhr-gas; equivalent of 500 hrs/yr/CT-oil.

Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code: OTHER
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 45 lb/hr
4. Equivalent Allowable Emissions: 45 lb/hour 184 tons/year
5. Method of Compliance (limit to 60 characters): CEM; Part 75; 24-hour Block average
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): Gas Firing: lb/hr at 32 degree F turbine inlet; TPY for 8,760 hrs/yr at 59 degree F turbine inlet.

B.

1. Basis for Allowable Emissions Code: OTHER
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 332 lb/hr
4. Equivalent Allowable Emissions: 332 lb/hour 75.75 tons/year
5. Method of Compliance (limit to 60 characters): CEM; Part 75
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): Oil Firing: lb/hr at 22 degree F turbine inlet; TPY equivalent of 500 hrs/yr/CT-oil at 59 degrees F turbine inlet.

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: CO
2. Total Percent Efficiency of Control: %
3. Potential Emissions: 113 lb/hour 378 tons/year
4. Synthetically Limited? [ ] Yes [X] No
5. Range of Estimated Fugitive/Other Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/yr
6. Emission Factor: Reference: Westinghouse, 1998
7. Emissions Method Code: [ ] 0 [ ] 1 [x] 2 [ ] 3 [ ] 4 [ ] 5
8. Calculation of Emissions (limit to 600 characters): See Section 2.0 in PSD Application
9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters): Max lb/hr for oil firing at 22 degree F turbine inlet; TPY at 59 degree F turbine inlet with 8,260 hrs/yr-gas; equivalent of 500 hrs/yr/CT-oil.

Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code: OTHER
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 91 lb/hr
4. Equivalent Allowable Emissions: 91 lb/hour 377 tons/year
5. Method of Compliance (limit to 60 characters): EPA Method 10
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): Gas Firing: lb/hr at 32 degree F turbine inlet; TPY for 8,760 hrs/yr at 59 degree F turbine inlet.

B.

1. Basis for Allowable Emissions Code: OTHER
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 113 lb/hr
4. Equivalent Allowable Emissions: 113 lb/hour 23 tons/year
5. Method of Compliance (limit to 60 characters): EPA Method 10
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): Oil Firing: lb/hr at 22 degree F turbine inlet; TPY equivalent of 500 hrs/yr/CT-oil at 59 degrees F turbine inlet.

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: VOC
2. Total Percent Efficiency of Control: %
3. Potential Emissions: 24 lb/hour 71.6 tons/year
4. Synthetically Limited? [ ] Yes [X] No
5. Range of Estimated Fugitive/Other Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/yr
6. Emission Factor: Reference: Westinghouse, 1998
7. Emissions Method Code: [ ] 0 [ ] 1 [X] 2 [ ] 3 [ ] 4 [ ] 5
8. Calculation of Emissions (limit to 600 characters): See Section 2.0 in PSD Application
9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters): Max lb/hr for oil firing at 22 degree F turbine inlet; TPY at 59 degree F turbine inlet with 8,260 hrs/yr-gas; equivalent of 500 hrs/yr/CT-oil.

Emissions Unit Information Section 1 of 2.

Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code: OTHER
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 17 lb/hr
4. Equivalent Allowable Emissions: 17 lb/hour 70 tons/year
5. Method of Compliance (limit to 60 characters): EPA Method 25A
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): Gas Firing: lb/hr at 32 degree F turbine inlet; TPY for 8,760 hrs/yr at 59 degree F turbine inlet.

B.

1. Basis for Allowable Emissions Code: OTHER
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 24 lb/hr
4. Equivalent Allowable Emissions: 24 lb/hour 5.5 tons/year
5. Method of Compliance (limit to 60 characters): EPA Method 25A
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): Oil Firing: lb/hr at 22 degree F turbine inlet; TPY equivalent of 500 hrs/yr/CT-oil at 59 degrees F turbine inlet.

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: SAM		
2. Total Percent Efficiency of Control: %		
3. Potential Emissions:	10 lb/hour	4.77 tons/year
4. Synthetically Limited? [ ] Yes [ ] No		
5. Range of Estimated Fugitive/Other Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/yr		
6. Emission Factor: 6.5 % SO2 Reference: Golder, 1998		
7. Emissions Method Code: [ ] 0 [ ] 1 [x] 2 [ ] 3 [ ] 4 [ ] 5		
8. Calculation of Emissions (limit to 600 characters): Emission Factor is converted to SAM. See Section 2.0 in PSD Application		
9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters): Max lb/hr for oil firing at 22 degree F turbine inlet; TPY at 59 degree F turbine inlet with 8,260 hrs/yr-gas; equivalent of 500 hrs/yr/CT-oil.		

Emissions Unit Information Section 1 of 2

Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code: OTHER
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: Pipeline Gas
4. Equivalent Allowable Emissions: 0.6 lb/hour 2.4 tons/year
5. Method of Compliance (limit to 60 characters): Fuel Sampling - Vendor
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): Gas Firing: lb/hr at 32 degree F turbine inlet; TPY for 8,760 hrs/yr at 59 degree F turbine inlet.

B.

1. Basis for Allowable Emissions Code: OTHER
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 0.05 % Sulfur oil
4. Equivalent Allowable Emissions: 10 lb/hour 2.25 tons/year
5. Method of Compliance (limit to 60 characters): Fuel Sampling - Vendor
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): Oil Firing: lb/hr at 22 degree F turbine inlet; TPY equivalent of 500 hrs/yr/CT-oil at 59 degrees F turbine inlet.

I. VISIBLE EMISSIONS INFORMATION
(Regulated Emissions Units Only)

Visible Emissions Limitations: Visible Emissions Limitation 1 of 3

1.	Visible Emissions Subtype: VE10
2.	Basis for Allowable Opacity: [ ] Rule [x] Other
3.	Requested Allowable Opacity Normal Conditions: 10 % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour
4.	Method of Compliance: EPA Method 9
5.	Visible Emissions Comment (limit to 200 characters): Gas Firing

Visible Emissions Limitations: Visible Emissions Limitation 2 of 3

1.	Visible Emissions Subtype: VE20
2.	Basis for Allowable Opacity: [ ] Rule [X] Other
3.	Requested Allowable Opacity Normal Conditions: 20 % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour
4.	Method of Compliance: EPA Method 9
5.	Visible Emissions Comment (limit to 200 characters): Oil Firing

I. VISIBLE EMISSIONS INFORMATION
(Regulated Emissions Units Only)

Visible Emissions Limitations: Visible Emissions Limitation 3 of 3

1.	Visible Emissions Subtype: VE99
2.	Basis for Allowable Opacity: [x] Rule [ ] Other
3.	Requested Allowable Opacity Normal Conditions: % Exceptional Conditions: 100 % Maximum Period of Excess Opacity Allowed: 60 min/hour
4.	Method of Compliance: None
5.	Visible Emissions Comment (limit to 200 characters): FDEP Rule 62-210.700(2); allowed for 2 hours (120 minutes) per 24 hours for startup, shutdown and malfunction.

Visible Emissions Limitations: Visible Emissions Limitation _____ of _____

1.	Visible Emissions Subtype:
2.	Basis for Allowable Opacity: [ ] Rule [ ] Other
3.	Requested Allowable Opacity Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour
4.	Method of Compliance:
5.	Visible Emissions Comment (limit to 200 characters):

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

Continuous Monitoring System Continuous Monitor 1 of 2

1. Parameter Code: EM	2. Pollutant(s): NOx
3. CMS Requirement: [X] Rule [ ] Other	
4. Monitor Information: Monitor Manufacturer: Not Yet Determined Model Number: Serial Number:	
5. Installation Date:	
6. Performance Specification Test Date:	
7. Continuous Monitor Comment (limit to 200 characters): NOx CEM required by 40 CFR Part 75. A carbon dioxide or oxygen monitor will be included.	

Continuous Monitoring System Continuous Monitor 2 of 2

1. Parameter Code: EM	2. Pollutant(s): NOx
3. CMS Requirement: [X] Rule [ ] Other	
4. Monitor Information: Monitor Manufacturer: Westinghouse Model Number: Serial Number:	
5. Installation Date:	
6. Performance Specification Test Date:	
7. Continuous Monitor Comment (limit to 200 characters): Parameter Code: WTF. Required by 40 CFR 60; Subpart GG; S.60.334; oil firing. Request NOx CEM in lieu of WTF monitoring.	

K. PREVENTION OF SIGNIFICANT DETERIORATION (PSD) INCREMENT TRACKING INFORMATION
(Regulated and Unregulated Emissions Units)

PSD Increment Consumption Determination

1. Increment Consuming for Particulate Matter or Sulfur Dioxide?

   If the emissions unit addressed in this section emits particulate matter or sulfur dioxide, answer the following series of questions to make a preliminary determination as to whether or not the emissions unit consumes PSD increment for particulate matter or sulfur dioxide. Check the first statement, if any, that applies and skip remaining statements.

   [x] The emissions unit is undergoing PSD review as part of this application, or has undergone PSD review previously, for particulate matter or sulfur dioxide. If so, emissions unit consumes increment.

   [ ] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after January 6, 1975. If so, baseline emissions are zero, and the emissions unit consumes increment.

   [ ] The facility addressed in this application is classified as an EPA major source and the emissions unit began initial operation after January 6, 1975, but before December 27, 1977. If so, baseline emissions are zero, and the emissions unit consumes increment.

   [ ] For any facility, the emissions unit began (or will begin) initial operation after December 27, 1977. If so, baseline emissions are zero, and emissions unit consumes increment.

   [ ] None of the above apply. If so, the baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

2. Increment Consuming for Nitrogen Dioxide?

If the emissions unit addressed in this section emits nitrogen oxides, answer the following series of questions to make a preliminary determination as to whether or not the emissions unit consumes PSD increment for nitrogen dioxide. Check first statement, if any, that applies and skip remaining statements.

[x] The emissions unit addressed in this section is undergoing PSD review as part of this application, or has undergone PSD review previously, for nitrogen dioxide. If so, emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after February 8, 1988. If so, baseline emissions are zero, and the source consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source and the emissions unit began initial operation after February 8, 1988, but before March 28, 1988. If so, baseline emissions are zero, and the source consumes increment.

[ ] For any facility, the emissions unit began (or will begin) initial operation after March 28, 1988. If so, baseline emissions are zero, and the emissions unit consumes increment.

[ ] None of the above apply. If so, baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

3.	Increment Consuming/Expanding Code:			
	PM	[x] C	[ ] E	[ ] Unknown
	SO_2	[x] C	[ ] E	[ ] Unknown
	NO_2	[x] C	[ ] E	[ ] Unknown
4.	Baseline Emissions:			
	PM	lb/hour		tons/year
	SO_2	lb/hour		tons/year
	NO_2			tons/year
5.	PSD Comment (limit to 200 characters):			
	See PSD Application			

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

Supplemental Requirements for All Applications

1.	Process Flow Diagram [x] Attached, Document ID: Fig 2-2 [ ] Not Applicable		[ ] Waiver Requested
2.	Fuel Analysis or Specification [x] Attached, Document ID: Tab 2-4 [ ] Not Applicable		[ ] Waiver Requested
3.	Detailed Description of Control Equipment [x] Attached, Document ID: Sec. 4.0 [ ] Not Applicable		[ ] Waiver Requested
4.	Description of Stack Sampling Facilities [x] Attached, Document ID: PSD Appl. [ ] Not Applicable		[ ] Waiver Requested
5.	Compliance Test Report [ ] Attached, Document ID: ____ [ ] Previously Submitted, Date: ____		[x] Not Applicable
6.	Procedures for Startup and Shutdown [ ] Attached, Document ID: ____		[x] Not Applicable
7.	Operation and Maintenance Plan [ ] Attached, Document ID: ____		[x] Not Applicable
8.	Supplemental Information for Construction Permit Application [x] Attached, Document ID: PSD Appl.		[ ] Not Applicable
9.	Other Information Required by Rule or Statute [x] Attached, Document ID: PSD Appl.		[ ] Not Applicable

Additional Supplemental Requirements for Category I Applications Only

10.	Alternative Methods of Operation [ ] Attached, Document ID: ____________ [ ] Not Applicable
11.	Alternative Modes of Operation (Emissions Trading) [ ] Attached, Document ID: ____________ [ ] Not Applicable
12.	Identification of Additional Applicable Requirements [ ] Attached, Document ID: ____________ [ ] Not Applicable
13.	Compliance Assurance Monitoring Plan [ ] Attached, Document ID: ____________ [ ] Not Applicable
14.	Acid Rain Permit Application (Hard Copy Required) [ ] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a)) Attached, Document ID: ____________ [ ] 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: ____________ [ ] Not Applicable

III. EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through L 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. Some of the subsections comprising the Emissions Unit Information Section of the form are intended for regulated emissions units only. Others are intended for both regulated and unregulated emissions units. Each subsection is appropriately marked.

A. TYPE OF EMISSIONS UNIT
(Regulated and Unregulated Emissions Units)

Type of Emissions Unit Addressed in This Section

1. 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.

2. Single Process, Group of Processes, or Fugitive Only? 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.

B. GENERAL EMISSIONS UNIT INFORMATION
(Regulated and Unregulated Emissions Units)

Emissions Unit Description and Status

1. Description of Emissions Unit Addressed in This Section (limit to 60 characters): CT-2; Power Block 2		
2. Emissions Unit Identification Number: [ ] No Corresponding ID [X] Unknown		
3. Emissions Unit Status Code: C	4. Acid Rain Unit? [X] Yes [ ] No	5. Emissions Unit Major Group SIC Code: 49
6. Emissions Unit Comment (limit to 500 characters): Westinghouse 501 F combustion turbine firing natural gas with distillate oil back-up.		

Emissions Unit Control Equipment Information

A.

1. Description (limit to 200 characters): Dry Low NOx combustion-natural gas firing
2. Control Device or Method Code: 25

B.

1. Description (limit to 200 characters): Selective Catalytic Reduction (SCR) - natural gas firing
2. Control Device or Method Code: 65

C.

1. Description (limit to 200 characters): Water Injection - distillate oil firing
2. Control Device or Method Code: 28

C. EMISSIONS UNIT DETAIL INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Details

1. Initial Startup Date:		
2. Long-term Reserve Shutdown Date:		
3. Package Unit: Manufacturer: Westinghouse	Model Number: 501F	
4. Generator Nameplate Rating:	165 MW	
5. Incinerator Information: Dwell Temperature:	°F	
Dwell Time:	seconds	
Incinerator Afterburner Temperature:	°F	

Emissions Unit Operating Capacity

1. Maximum Heat Input Rate:	1,822	mmBtu/hr
2. Maximum Incineration Rate:	lbs/hr	tons/day
3. Maximum Process or Throughput Rate:		
4. Maximum Production Rate:		
5. Operating Capacity Comment (limit to 200 characters): Heat input is HHV; heat input at 59 degree F turbine inlet temperature; MW nominal rating.		

Emissions Unit Operating Schedule

1. Requested Maximum Operating Schedule:			
	hours/day		days/week
	weeks/yr	8,760	hours/yr

D. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

Rule Applicability Analysis (Required for Category II Applications and Category III applications involving non Title-V sources. See Instructions.)

List of Applicable Regulations (Required for Category I applications and Category III applications involving Title-V sources. See Instructions.)

See Attachment PB2-EU1-D
See PSD Application

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

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: Fig 2-1
2. Emission Point Type Code: [x] 1 [ ] 2 [ ] 3 [ ] 4
3. Descriptions of Emissions Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point): Exhausts through a single stack.
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:
5. Discharge Type Code: [ ] D [ ] F [ ] H [ ] P [ ] R [x] V [ ] W
6. Stack Height: 125 feet
7. Exit Diameter: 19 feet
8. Exit Temperature: 206 °F

9. Actual Volumetric Flow Rate:	1,035,668 acfm
10. Percent Water Vapor:	%
11. Maximum Dry Standard Flow Rate:	dscfm
12. Nonstack Emission Point Height:	feet
13. Emission Point UTM Coordinates: Zone: 17 East (km): 414.4 North (km): 3073.9	
14. Emission Point Comment (limit to 200 characters): **Temperature and flow for natural gas at 59 degrees turbine inlet; See Tables 2-1 and 2-2 in PSD application.**	

F. SEGMENT (PROCESS/FUEL) INFORMATION
(Regulated and Unregulated Emissions Units)

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) (limit to 500 characters): Natural Gas	
2. Source Classification Code (SCC): 2-01-002-01	
3. SCC Units: Million Cubic Feet	
4. Maximum Hourly Rate: 1.85	5. Maximum Annual Rate: 15,201
6. Estimated Annual Activity Factor:	
7. Maximum Percent Sulfur:	8. Maximum Percent Ash:
9. Million Btu per SCC Unit: 1,050	
10. Segment Comment (limit to 200 characters): Based on 1,050 BTU/CF (HHV); maximum hourly at 32 degrees F; annual at 59 degrees F; turbine inlet temperatures.	

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) (limit to 500 characters): Distillate Fuel Oil	
2. Source Classification Code (SCC): 2-01-001-01	
3. SCC Units: 1,000 Gallons Used	
4. Maximum Hourly Rate: 15.1	5. Maximum Annual Rate: 6,881
6. Estimated Annual Activity Factor:	
7. Maximum Percent Sulfur: 0.05	8. Maximum Percent Ash:
9. Million Btu per SCC Unit: 129	
10. Segment Comment (limit to 200 characters): BTU based on HHV of 129 MMBtu/1,000 gallons. Aggregate fuel usage of 13,762,806 gallons per year requested for Power Block 2.	

G. EMISSIONS UNIT POLLUTANTS
(Regulated and Unregulated Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM			EL
SO2			EL
NOx	026	065	EL
CO			EL
VOC			EL
SAM			El

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: PM

2. Total Percent Efficiency of Control: %

3. Potential Emissions: 46 lb/hour 49 tons/year

4. Synthetically Limited? [ ] Yes [X] No

5. Range of Estimated Fugitive/Other Emissions:

   [ ] 1 [ ] 2 [ ] 3 ____________ to ____________ tons/yr

6. Emission Factor:

   Reference: Westinghouse, 1998

7. Emissions Method Code:

   [ ] 0 [ ] 1 [X] 2 [ ] 3 [ ] 4 [ ] 5

8. Calculation of Emissions (limit to 600 characters):

   See Section 2.0 in PSD Application

9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters):

   Max lb/hr for oil firing at 22 degrees F turbine inlet; TPY at 59 degree F turbine inlet with 8,260 hrs/yr-gas; equivalent of 500 hrs/yr/CT-oil.

Emissions Unit Information Section 2 of 2

Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code: OTHER
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 10 percent Opacity
4. Equivalent Allowable Emissions: 9.8 lb/hour 40.7 tons/year
5. Method of Compliance (limit to 60 characters): EPA Method 9
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): Gas Firing: lb/hr at 32 degree F turbine inlet; TPY for 8,760 hrs/yr at 59 degree F turbine inlet.

B.

1. Basis for Allowable Emissions Code: OTHER
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 20 percent Opacity
4. Equivalent Allowable Emissions: 46 lb/hour 11.5 tons/year
5. Method of Compliance (limit to 60 characters): EPA Method 9
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): Oil firing: lb/hr at 22 degree F turbine inlet; TPY equivalent of 500 hrs/yr/CT-oil at 59 degrees F turbine inlet.

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: SO2

2. Total Percent Efficiency of Control: %

3. Potential Emissions: 104 lb/hour 46.5 tons/year

4. Synthetically Limited? [ ] Yes [X] No

5. Range of Estimated Fugitive/Other Emissions:

   [ ] 1 [ ] 2 [ ] 3 ________ to ________ tons/yr

6. Emission Factor:

   Reference: Westinghouse, 1998

7. Emissions Method Code:

   [ ] 0 [ ] 1 [X] 2 [ ] 3 [ ] 4 [ ] 5

8. Calculation of Emissions (limit to 600 characters):

   See Section 2.0 in PSD Application

9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters):

   Max lb/hr for oil firing at 22 degree F turbine inlet; TPY at 59 degree F turbine inlet; TPY at 59 degree F turbine inlet with 8,260 hrs/yr-gas; equivalent of 500 hrs/yr/CT-oil.

Emissions Unit Information Section 2 of 2.

Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code: OTHER
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: Pipeline Gas
4. Equivalent Allowable Emissions: 6 lb/hour 24.1 tons/year
5. Method of Compliance (limit to 60 characters): Fuel Sampling - Vendor
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): Gas Firing: lb/hr at 32 degree F turbine inlet; TPY for 8,760 hrs/yr at 59 degree F turbine inlet.

B.

1. Basis for Allowable Emissions Code: OTHER
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 0.05 % Sulfur Oil
4. Equivalent Allowable Emissions: 104 lb/hour 23.75 tons/year
5. Method of Compliance (limit to 60 characters): Fuel Sampling - Vendor
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): Oil Firing: lb/hr at 22 degree F turbine inlet; TPY equivalent of 500 hrs/yr/CT-oil at 59 degrees F turbine inlet.

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: **NOx**

2. Total Percent Efficiency of Control: %

3. Potential Emissions: **332** lb/hour **249.5** tons/year

4. Synthetically Limited? [ ] Yes [X] No

5. Range of Estimated Fugitive/Other Emissions:

   [ ] 1 [ ] 2 [ ] 3 ___________ to ___________ tons/yr

6. Emission Factor:

   Reference: **Westinghouse, 1998**

7. Emissions Method Code:

   [ ] 0 [ ] 1 [X] 2 [ ] 3 [ ] 4 [ ] 5

8. Calculation of Emissions (limit to 600 characters):

   Maximum lb/hour based on oil-firing. Does not include provision for fuel-bound nitrogen (FBN). An allowance up to 0.03 percent FBN is requested. See Section 2.0 in PSD Application.

9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters):

   Max lb/hr for oil firing at 22 degree F turbine inlet; TPY at 59 degree F turbine inlet with 8,260 hrs/yhr-gas; equivalent of 500 hrs/yr/CT-oil.

Emissions Unit Information Section 2 of 2

Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code: OTHER
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 45 lb/hr
4. Equivalent Allowable Emissions: 45 lb/hour 184 tons/year
5. Method of Compliance (limit to 60 characters): CEM; Part 75; 24-hour Block average
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): Gas Firing: lb/hr at 32 degree F turbine inlet; TPY for 8,760 hrs/yr at 59 degree F turbine inlet.

B.

1. Basis for Allowable Emissions Code: OTHER
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 332 lb/hr
4. Equivalent Allowable Emissions: 332 lb/hour 75.75 tons/year
5. Method of Compliance (limit to 60 characters): CEM; Part 75
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): Oil Firing: lb/hr at 22 degree F turbine inlet; TPY equivalent of 500 hrs/yr/CT-oil at 59 degrees F turbine inlet.

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: CO					
2. Total Percent Efficiency of Control: %					
3. Potential Emissions: 113 lb/hour			378 tons/year		
4. Synthetically Limited? [ ] Yes [X] No					
5. Range of Estimated Fugitive/Other Emissions:					
[ ] 1	[ ] 2	[ ] 3	________ to ________ tons/yr		
6. Emission Factor:					
Reference: Westinghouse, 1998					
7. Emissions Method Code:					
[ ] 0	[ ] 1	[x] 2	[ ] 3	[ ] 4	[ ] 5
8. Calculation of Emissions (limit to 600 characters):					
See Section 2.0 in PSD Application					
9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters):					
Max lb/hr for oil firing at 22 degree F turbine inlet; TPY at 59 degree F turbine inlet with 8,260 hrs/yr-gas; equivalent of 500 hrs/yr/CT-oil.					

Emissions Unit Information Section 2 **of** 2

Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code:
   OTHER

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units:
   91 lb/hr

4. Equivalent Allowable Emissions: **91** lb/hour **377** tons/year

5. Method of Compliance (limit to 60 characters):
   EPA Method 10

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters):
   Gas Firing: lb/hr at 32 degree F turbine inlet; TPY for 8,760 hrs/yr at 59 degree F turbine inlet.

B.

1. Basis for Allowable Emissions Code: **OTHER**

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units:
   113 lb/hr

4. Equivalent Allowable Emissions: **113** lb/hour **23** tons/year

5. Method of Compliance (limit to 60 characters):
   EPA Method 10

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters):
   Oil Firing: lb/hr at 22 degree F turbine inlet; TPY equivalent of 500 hrs/yr/CT-oil at 59 degrees F turbine inlet.

Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code: OTHER	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units: 17 lb/hr	
4. Equivalent Allowable Emissions: 17 lb/hour	70 tons/year
5. Method of Compliance (limit to 60 characters): EPA Method 25A	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): **Gas Firing: lb/hr at 32 degree F turbine inlet; TPY for 8,760 hrs/yr at 59 degree F turbine inlet.**	

B.

1. Basis for Allowable Emissions Code: OTHER	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units: 24 lb/hr	
4. Equivalent Allowable Emissions: 24 lb/hour	5.5 tons/year
5. Method of Compliance (limit to 60 characters): EPA Method 25A	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): **Oil Firing: lb/hr at 22 degree F turbine inlet; TPY equivalent of 500 hrs/yr/CT-oil at 59 degrees F turbine inlet.**	

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: SAM
2. Total Percent Efficiency of Control: %
3. Potential Emissions: 10 lb/hour 4.77 tons/year
4. Synthetically Limited? [ ] Yes [ ] No
5. Range of Estimated Fugitive/Other Emissions: [ ] 1 [ ] 2 [ ] 3 ________ to ________ tons/yr
6. Emission Factor: 6.5 % SO2 Reference: Golder, 1998
7. Emissions Method Code: [ ] 0 [ ] 1 [x] 2 [ ] 3 [ ] 4 [ ] 5
8. Calculation of Emissions (limit to 600 characters): Emission Factor is converted to SAM. See Section 2.0 in PSD Application
9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters): Max lb/hr for oil firing at 22 degree F turbine inlet; TPY at 59 degree F turbine inlet with 8,260 hrs/yr-gas; equivalent of 500 hrs/yr/CT-oil.

Emissions Unit Information Section 2 **of** 2.

Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code: **OTHER**	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units: **Pipeline Gas**	
4. Equivalent Allowable Emissions: **0.6** lb/hour	**2.4** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel Sampling - Vendor**	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): **Gas Firing: lb/hr at 32 degree F turbine inlet; TPY for 8,760 hrs/yr at 59 degree F turbine inlet.**	

B.

1. Basis for Allowable Emissions Code: **OTHER**	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units: **0.05 % Sulfur oil**	
4. Equivalent Allowable Emissions: **10** lb/hour	**2.25** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel Sampling - Vendor**	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): **Oil Firing: lb/hr at 22 degree F turbine inlet; TPY equivalent of 500 hrs/yr/CT-oil at 59 degrees F turbine inlet.**	

I. VISIBLE EMISSIONS INFORMATION
(Regulated Emissions Units Only)

Visible Emissions Limitations: Visible Emissions Limitation 1 of 3

1.	Visible Emissions Subtype: VE10
2.	Basis for Allowable Opacity: [ ] Rule [x] Other
3.	Requested Allowable Opacity Normal Conditions: 10 % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour
4.	Method of Compliance: EPA Method 9
5.	Visible Emissions Comment (limit to 200 characters): Gas Firing

Visible Emissions Limitations: Visible Emissions Limitation 2 of 3

1.	Visible Emissions Subtype: VE20
2.	Basis for Allowable Opacity: [ ] Rule [X] Other
3.	Requested Allowable Opacity Normal Conditions: 20 % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour
4.	Method of Compliance: EPA Method 9
5.	Visible Emissions Comment (limit to 200 characters): Oil Firing

I. VISIBLE EMISSIONS INFORMATION
(Regulated Emissions Units Only)

Visible Emissions Limitations: Visible Emissions Limitation 3 of 3

1.	Visible Emissions Subtype: VE99	
2.	Basis for Allowable Opacity: [x] Rule [ ] Other	
3.	Requested Allowable Opacity Normal Conditions: % Exceptional Conditions: 100 % Maximum Period of Excess Opacity Allowed: 60 min/hour	
4.	Method of Compliance: None	
5.	Visible Emissions Comment (limit to 200 characters): FDEP Rule 62-210.700(2); allowed for 2 hours (120 minutes) per 24 hours for startup, shutdown and malfunction.	

Visible Emissions Limitations: Visible Emissions Limitation _____ of _____

1.	Visible Emissions Subtype:	
2.	Basis for Allowable Opacity: [ ] Rule [ ] Other	
3.	Requested Allowable Opacity Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4.	Method of Compliance:	
5.	Visible Emissions Comment (limit to 200 characters):	

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

Continuous Monitoring System Continuous Monitor 1 of 2

1. Parameter Code: EM	2. Pollutant(s): NOx
3. CMS Requirement: [X] Rule [ ] Other	
4. Monitor Information: Monitor Manufacturer: Not Yet Determined Model Number: Serial Number:	
5. Installation Date:	
6. Performance Specification Test Date:	
7. Continuous Monitor Comment (limit to 200 characters): NOx CEM required by 40 CFR Part 75. A carbon dioxide or oxygen monitor will be included.	

Continuous Monitoring System Continuous Monitor 2 of 2

1. Parameter Code: EM	2. Pollutant(s): NOx
3. CMS Requirement: [X] Rule [ ] Other	
4. Monitor Information: Monitor Manufacturer: Westinghouse Model Number: Serial Number:	
5. Installation Date:	
6. Performance Specification Test Date:	
7. Continuous Monitor Comment (limit to 200 characters): Parameter Code: WTF. Required by 40 CFR 60; Subpart GG; S.60.334; oil firing. Request NOx CEM in lieu of WTF monitoring.	

K. PREVENTION OF SIGNIFICANT DETERIORATION (PSD) INCREMENT TRACKING INFORMATION
(Regulated and Unregulated Emissions Units)

PSD Increment Consumption Determination

1. Increment Consuming for Particulate Matter or Sulfur Dioxide?

   If the emissions unit addressed in this section emits particulate matter or sulfur dioxide, answer the following series of questions to make a preliminary determination as to whether or not the emissions unit consumes PSD increment for particulate matter or sulfur dioxide. Check the first statement, if any, that applies and skip remaining statements.

   [x] The emissions unit is undergoing PSD review as part of this application, or has undergone PSD review previously, for particulate matter or sulfur dioxide. If so, emissions unit consumes increment.

   [ ] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after January 6, 1975. If so, baseline emissions are zero, and the emissions unit consumes increment.

   [ ] The facility addressed in this application is classified as an EPA major source and the emissions unit began initial operation after January 6, 1975, but before December 27, 1977. If so, baseline emissions are zero, and the emissions unit consumes increment.

   [ ] For any facility, the emissions unit began (or will begin) initial operation after December 27, 1977. If so, baseline emissions are zero, and emissions unit consumes increment.

   [ ] None of the above apply. If so, the baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

2. Increment Consuming for Nitrogen Dioxide?

If the emissions unit addressed in this section emits nitrogen oxides, answer the following series of questions to make a preliminary determination as to whether or not the emissions unit consumes PSD increment for nitrogen dioxide. Check first statement, if any, that applies and skip remaining statements.

[x] The emissions unit addressed in this section is undergoing PSD review as part of this application, or has undergone PSD review previously, for nitrogen dioxide. If so, emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after February 8, 1988. If so, baseline emissions are zero, and the source consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source and the emissions unit began initial operation after February 8, 1988, but before March 28, 1988. If so, baseline emissions are zero, and the source consumes increment.

[ ] For any facility, the emissions unit began (or will begin) initial operation after March 28, 1988. If so, baseline emissions are zero, and the emissions unit consumes increment.

[ ] None of the above apply. If so, baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

3.	Increment Consuming/Expanding Code:			
	PM	[x] C	[ ] E	[ ] Unknown
	SO_2	[x] C	[ ] E	[ ] Unknown
	NO_2	[x] C	[ ] E	[ ] Unknown
4.	Baseline Emissions:			
	PM	lb/hour		tons/year
	SO_2	lb/hour		tons/year
	NO_2			tons/year
5.	PSD Comment (limit to 200 characters):			
	See PSD Application			

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

Supplemental Requirements for All Applications

1.	Process Flow Diagram [x] Attached, Document ID: Fig 2-2 [ ] Not Applicable	[ ] Waiver Requested
2.	Fuel Analysis or Specification [x] Attached, Document ID: Tab 2-4 [ ] Not Applicable	[ ] Waiver Requested
3.	Detailed Description of Control Equipment [x] Attached, Document ID: Sec. 4.0 [ ] Not Applicable	[ ] Waiver Requested
4.	Description of Stack Sampling Facilities [x] Attached, Document ID: PSD Appl. [ ] Not Applicable	[ ] Waiver Requested
5.	Compliance Test Report [ ] Attached, Document ID: ____ [ ] Previously Submitted, Date: ____	[x] Not Applicable
6.	Procedures for Startup and Shutdown [ ] Attached, Document ID: ____	[x] Not Applicable
7.	Operation and Maintenance Plan [ ] Attached, Document ID: ____	[x] Not Applicable
8.	Supplemental Information for Construction Permit Application [x] Attached, Document ID: PSD Appl.	[ ] Not Applicable
9.	Other Information Required by Rule or Statute [x] Attached, Document ID: PSD Appl.	[ ] Not Applicable

Additional Supplemental Requirements for Category I Applications Only

10.	Alternative Methods of Operation [ ] Attached, Document ID: ____________ [ ] Not Applicable
11.	Alternative Modes of Operation (Emissions Trading) [ ] Attached, Document ID: ____________ [ ] Not Applicable
12.	Identification of Additional Applicable Requirements [ ] Attached, Document ID: ____________ [ ] Not Applicable
13.	Compliance Assurance Monitoring Plan [ ] Attached, Document ID: ____________ [ ] Not Applicable
14.	Acid Rain Permit Application (Hard Copy Required) [ ] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a)) Attached, Document ID: ____________ [ ] 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: ____________ [ ] Not Applicable