21 West Church Street
Jacksonville, Florida 32202-3139

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JUN 21 2000
BUREAU OF AIR REGULATION

JEA

June 13, 2000

Mr. Al Linero, P.E.
Administrator
New Source Review Section
Bureau of Air Quality
Department of Environmental Protection
111 South Magnolia Dr, Suite 4
Tallahassee, FL 32301

RE: Brandy Branch Facility (DEP File No. 031485-001-AC, PSD-FL-267)
Request for permit revision

Dear Mr. Linero:

Currently, in the above referenced permit, the shutdown date of the Southside Generating Station is linked to submittal of the Title V operating permit application for the Brandy Branch facility (see Administrative Requirement 14 on page 5 of 14 of the attached permit).

The original intent of this condition was to allow operation of the Southside Generating Station (SGS) until its scheduled decommissioning date of October 31, 2001, with the option of operating until as late as October 31, 2002 in the event of problems with the Brandy Branch facility construction. Unfortunately, the wording in the permit does not accomplish this goal. We only recently realized this, and are now seeking to correct this situation. Apparently, a misunderstanding with regard to the definitions of "commencement of operation" and "commercial operation" in the Title V rules allowed this situation to go unnoticed during the permit writing process.

JEA voluntarily added the condition to shut down SGS to the Brandy Branch permit because haze modeling at the screening level using CALPUFF Lite showed a greater than 5% impact on haze in the Class I areas, and our schedule would not allow us to wait for the results of the refined regional haze analysis. (Please see the attached letter from the Fish and Wildlife Service). The regional haze analysis was later completed using CALPUFF. The results appear in the attached report from Golder Associates showing a predicted maximum impact on the visibility in the Class I areas of 2.6% with all three of the new Brandy Branch units operating at their maximum permitted emission rates on #2 diesel oil backup fuel. This is considerably below the significance threshold of 5%.

Our current schedule for the construction of Brandy Branch Unit 1 would require us to wait until the very end of the regulatory deadline to submit our Title V operating permit application in order to prevent premature shutdown of SGS Units 4 and 5. Even with a last minute submittal, we would still be required to shut down SGS one to two months prior to its scheduled decommissioning date of October 31, 2001. This could result in a capacity shortage in the September/October, 2001 timeframe and a possible hardship for JEA and its customers.

To correct this situation, and in light of the above information showing an insignificant impact on the Class I areas from this project, it is requested that a permit revision to Administrative Requirement 14 be issued. The following suggested language change is provided for your consideration:

From:

"14. Retirement of existing facility: In accordance with JEA's analyses of regional haze in the nearby Class I areas, the Brandy Branch facility may cause or contribute to haze values greater that 5%. In order to mitigate this possibility, JEA will limit the operation of the combustion turbines permitted herein to a maximum of 16 hours per day of oil operation. Additionally, so as to cause a net benefit to the nearby Class I areas, JEA shall retire the existing Southside Facility (AIRS ID 0310046) located at 801 Colorado Avenue, Jacksonville, Florida upon JEA's application for a Title V permit for the Brandy Branch facility (including certification that the facility is in compliance with applicable requirements and permit conditions). JEA shall concurrently submit a letter from the designated representative of the Southside facility certifying that the facility has been shutdown and that related permits are being surrendered. This shall occur on or before October 31, 2002."

To:

"14. Retirement of existing facility: JEA will limit the operation of the combustion turbines permitted herein to a maximum of 16 hours per day of oil operation. Additionally, so as to cause a net benefit to the nearby Class I areas, JEA shall retire the existing Southside Facility (AIRS ID 0310046) located at 801 Broadcast Place, Jacksonville, Florida on or before October 31, 2001. JEA shall concurrently submit a letter from the designated representative of the Southside facility certifying that the facility has been shutdown and that related permits are being surrendered."

JEA previously provided the Department with the results of our ambient modeling analysis showing that no ambient standards or increments will be violated by this project. That analysis did not use the shutdown of SGS to offset modeled impacts.

Finally, while we are prepared to surrender the permits for our main generating units at SGS (Units 4 and 5), certain activities and unregulated/insignificant unit operations will continue during the decommissioning process (such as the gas fired auxiliary boiler, emergency generator, fuel storage tanks, welding, etc.). Please advise if we need to take any additional action to continue these activities which already appear in our Title V permit.

If you have any questions with regard to this matter, please contact me at (904) 665-6247.

Sincerely,

N. Bert Gianazza, P.E.
Environmental Permitting
& Compliance

Attachments: As Noted.

cc: C. Fancy, P.E., FDEP
S. Pace, P.E., RESD

bc: J. Connolly
C. Bond
G. Quick
E. Mims
A. Mann
B. Gianazza
T. Hillman (w attc.)
File (w attc.)
4,13

BBREV

United States Department of the Interior

FISH AND WILDLIFE SERVICE
1875 Century Boulevard
Atlanta, Georgia 30345

IN REPLY REFER TO:

August 12, 1999

RECEIVED

AUG 17 1999

BUREAU OF AIR REGULATION

Re: PSD-FL-267

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 additional information submitted by Jacksonville Electric Authority (JEA) pertaining to its Brandy Branch project in Baldwin, Florida. The project is located 34 km southeast of Okefenokee Wilderness and 127 km southwest of Wolf Island Wilderness, both Class I air quality areas, administered by the U.S. Fish and Wildlife Service (FWS). The technical review comments from our Air Quality Branch are enclosed. In summary, JEA's regional haze analysis predicts that the project will significantly contribute to visibility impairment in Okefenokee. Based on this information, FWS would object to the issuance of a permit for the project. The technical review document summarizes the options available to JEA, including choosing not to proceed with the project, reducing the project's emissions, offsetting the project's emissions with the shutdown of JEA's Southside Station, and conducting a more refined modeling analysis. In any case, JEA must demonstrate that the Brandy Branch project will not further reduce visibility in the Okefenokee Class I area.

Thank you for the opportunity to comment on this permit application. We appreciate your cooperation in notifying us of proposed projects with the potential to impact the air quality and related resources of our Class I air quality areas. 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

cc: M. Halpin, BAR
Duval Co.
NED
EPA
C. Holladay, BAR
B. Gianazza, JEA
A. Compaan, B+V

Enclosure

Technical Review of Additional Information
for Jacksonville Electric Authority's Brandy Branch Generating Station
Baldwin, Florida
by
Air Quality Branch, Fish and Wildlife Service – Denver
August 3, 1999

PSD-FL-267

Jacksonville Electric Authority (JEA) is proposing to install three 170 MW simple cycle combustion turbines at their Brandy Branch Facility. The turbines will fire natural gas as the primary fuel, with low sulfur (less than 0.05 %) fuel oil as a back-up fuel. The Brandy Branch Facility is located 34 km southeast of Okefenokee Wilderness and 127 km southwest of Wolf Island Wilderness, both Class I air quality areas administered by the U.S. Fish and Wildlife Service (FWS). The project will result in PSD-significant increases in emissions of nitrogen oxides (NO_X), sulfur dioxide (SO_2), particulate matter (PM), fine particulate matter less than 10 microns in diameter (PM-10), carbon monoxide (CO), and sulfuric acid mist (SAM). Proposed emissions (in tons per year – TPY) are summarized below.

POLLUTANT	EMISSIONS INCREASE (TPY)
NO_X	858
SO_2	124
PM-10	75
CO	366
SAM	15.2

Air Quality Related Values (AQRV) Analysis

JEA performed a regional haze analysis for Wolf Island, concluding that the project would not contribute significantly to visibility impairment in the area. In December 1998, we advised JEA that they should also evaluate regional haze impacts in Okefenokee. Regional haze analyses are required of sources greater than 50 km from a receptor in a Class I area. Although the project was only 34 km from the nearest boundary of the Class I area, the project was more than 50 km from some receptors in the Class I area. (Okefenokee is approximately 55 km from south to north.)

An Industrial Source Complex (ISC) modeling analysis by JEA indicated that the project had the potential to significantly contribute to regional haze at Okefenokee. On June 9, 1999, we advised the applicant, via phone, that they had several options, including reducing production, accepting lower emissions limits, or performing a refined modeling analysis (CALPUFF-Lite or CALPUFF). In any case, they needed to demonstrate that the project's emissions would not significantly contribute to visibility impairment in the Class I area.

REFINED REGIONAL HAZE ANALYSES FOR THE BRANDY BRANCH FACILITY

Prepared For:

Jacksonville Electric Authority
21 West Church Street
Jacksonville, Florida 32202-3139

Submitted By:

Golder Associates Inc.
6241 NW 23rd Street, Suite 500
Gainesville, Florida 32653-1500

Black & Veatch
11401 Lamar Avenue
Overland, Kansas 66211

September 1999
9937577B/R1

DISTRIBUTION:
2 Copies - FDEP
1 Copy - JEA
1 Copy - FWS
1 Copy - Black & Veatch
2 Copies - Golder Associates

ACKNOWLEDGEMENT

Golder wishes to express their gratitude to the air modeling staff of Black & Veatch for their helpful assistance in the performance of this project.

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EXECUTIVE SUMMARY

Jacksonville Electric Authority (JEA) is proposing to construct three 170 Mw simple-cycle combustion turbines (nominal 500 Mw) at the Brandy Branch Power Plant, to be located near the city of Baldwin in northeastern Florida, illustrated in Figure 1-1. As part of the air impact evaluation for the proposed facility, the Florida Department of Environmental Projection (FDEP) has requested that an analysis of the proposed facility's affect on regional haze be performed for the Okefenokee National Wildlife Refuge (ONWR). The ONWR is a Prevention of Significant Deterioration (PSD) Class I area located in southeastern Georgia approximately 34 to 96 km north-northwest of the proposed facility site. Class I areas are afforded special environmental protection through the use of Air Quality Related Values (AQRVs). The AQRV of interest in this report is regional haze.

The CALPUFF analysis presented in this report a refinement of a previous "Level II" regional haze screening analysis provided by JEA in DRAFT to the FDEP on June 23, 1999. The Level II screening analysis, also referred to as a "CALPUFF Lite" analysis, was unable to demonstrate compliance with the imposed limits on regional haze. This analysis is a refinement of the earlier screening analysis and is based on the use of more realistic (i.e., less conservative) modeling inputs and assumptions.

The CALPUFF analysis closely followed those procedures recommended in the Interagency Workgroup on Air Quality Modeling (IWAQM) Phase II report dated December 1998 in coordination with the FDEP and the U.S. Fish and Wildlife Service (FWS) which is the Federal Land Manager (FLM) for the ONWR. This report includes a discussion of the meteorological and geophysical databases used in the analysis, the preparation of those databases for introduction into the modeling system, the air modeling approach, and the air modeling results. The model parameter settings used for the analysis are also provided.

The results of the refined modeling analysis indicate that the maximum visibility degradation is approximately 2.6 percent (0.26 deciviews), approximately half of the criteria of 5 percent

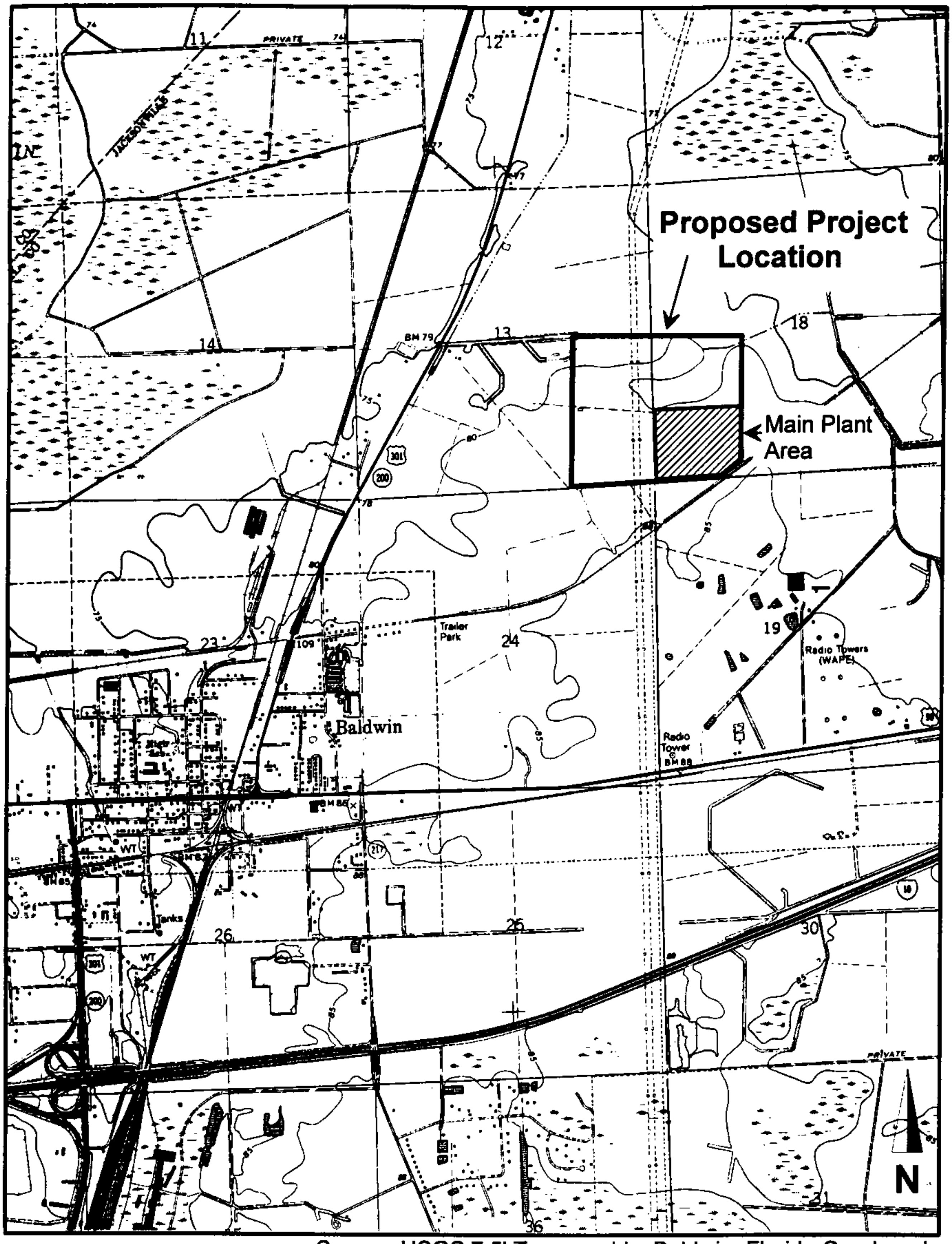
(0.5 deciviews). Thus, the maximum proposed emissions for the proposed facility are not expected to adversely impact existing regional haze levels at the Okefenokee NWR Class I area.

1.0 INTRODUCTION

Jacksonville Electric Authority (JEA) is proposing to build a 500 Mw power plant near Baldwin, Duval County, Florida. The proposed facility will be located approximately 34 km south-southeast of the southernmost boundary of the Okefenokee National Wildlife Refuge, a Prevention of Significant Deterioration (PSD) Class I Area. The location of the proposed facility is presented in Figure 1-1. On behalf of JEA and their engineers Black and Veatch (B&V), Golder Associates Inc. (Golder) has completed a refined regional haze analysis to determine the potential change in background regional haze levels at the ONWR.

The regional haze analysis calculated a deciview change in accordance with the Interagency Workgroup on Air Quality Models (IWAQM) guidelines. The guidelines apply air dispersion model results for predicted maximum 24-hour sulfate (SO_4), nitrate (NO_3), and fine particulate (PM_{10}) concentrations and the use of conservative chemical equations for estimating ammonium sulfate [$(NH_4)_2SO_4$] and ammonium nitrate (NH_4NO_3) concentrations. The analysis then applies existing data from the FLM to calculate the visibility change.

This report is divided into four sections, including this introduction. Section 2.0 of this report discusses the analysis methodology and model inputs. Section 3.0 of this report presents the analysis results.



Source: USGS 7.5' Topographic, Baldwin, Florida Quadrangle

Proposed Project Location

Figure 1-1

2.0 METHODOLOGY AND MODEL INPUTS

2.1 VISIBILITY NOMENCLATURE

Visibility is an AQRV for the ONWR. Visibility can take the form of plume blight for nearby areas, or regional haze for long distances (e.g., distances beyond 50 km). Because a substantial portion of the ONWR lies beyond 50 km from the proposed facility, the change in visibility is analyzed as regional haze at those locations of the ONWR. Current regional haze guidelines characterize a change in visibility by either of the following methods:

1. Change in the visual range, defined as the greatest distance that a large dark object can be seen, or
2. Change in the light-extinction coefficient (b_{ext}).

The b_{ext} is the attenuation of light per unit distance due to the scattering and absorption by gases and particles in the atmosphere. A change in the extinction coefficient produces a perceived visual change that is measured by a visibility index called the deciview. The deciview (dv) is defined as:

$$dv = 10 \ln (1 + b_{exts} / b_{extb})$$

where: b_{exts} is the extinction coefficient calculated for the source, and
b_{extb} is the background extinction coefficient

A similar index that simply quantifies the percent change in visibility due to the operation of a source is calculated as:

$$\Delta\% = (b_{exts} / b_{extsb}) \times 100$$

2.2 INTERAGENCY WORKGROUP ON AIR QUALITY MODELING (IWAQM) GUIDELINES

The CALPUFF air modeling analysis followed the recommendations contained in the *IWAQM Phase II Summary Report and Recommendations for Modeling Long Range Transport Impacts,* (EPA, 12/98). Table 2-1 summarizes the IWAQM Phase II recommendations.

Table 2-1
Outline of IWAQM Level II Refined Modeling Analyses Recommendations*

Meteorology	Use CALMET (minimum 6 to 10 layers in the vertical; top layer must extend above the maximum mixing depth expected); horizontal domain extends 50 to 80 km beyond outer receptors and sources being modeled; terrain elevation and land-use data is resolved for the situation.
Receptors	Within Class I area(s) of concern; obtain regulatory concurrence on coverage.
Dispersion	1. CALPUFF with default dispersion settings. 2. Use MESOPUFF II chemistry with wet and dry deposition 3. Define background values for ozone and ammonia for area
Processing	Use highest predicted 24-hr SO_4, PM_{10} and NO_3 values; compute a day-average relative humidity factor (f(RH)) for the worst day for each predicted species, calculate extinction coefficients and compute percent change in extinction using the FLM supplied background extinction.

**IWAQM Phase II Summary Report and Recommendations for Modeling Long Range Transport Impacts* (EPA, 12/98)

Refined impacts are calculated as follows:

1. Obtain maximum 24-hour SO_4 and NO_3 impacts, in units of micrograms per cubic meter ($\mu g/m^3$).
2. Convert the SO_4 impact to $(NH_4)_2SO_4$ by the following formula:

   $(NH_4)_2SO_4$ (μg/m3) = SO_4 ($\mu g/m^3$) x molecular weight $(NH_4)_2SO_4$ / molecular weight SO_4

   $(NH_4)_2SO_4$ ($\mu g/m^3$) = SO_4 ($\mu g/m^3$) x 132/96 = SO_4 ($\mu g/m^3$) x 1.375
   Convert the NO_3 impact to NH_4NO_3 by the following formula:
   NH_4NO_3 (μg/m3) = NO_3 ($\mu g/m^3$) x molecular weight NH_4NO_3 / molecular weight NO_3

   NH_4NO_3 ($\mu g/m^3$) = NO_3 ($\mu g/m^3$) x 80/62 = NO_3 ($\mu g/m^3$) x 1.29

3. Compute b_{exts} (extinction coefficient calculated for the source) with the following formula:

   $b_{exts} = 3 \times NH_4NO_3 \times f(RH) + 3 \times (NH_4)_2SO_4 \times f(RH) + 3 \times PM_{10}$

4. Compute b_{extb} (background extinction coefficient) using the background visual range (km) from the FLM with the following formula:

   $b_{extb} = 3.912 / \text{Visual range (km)}$

5. Compute the change in extinction coefficients:

   in terms of deciviews:

   $dv = 10 \ln (1 + b_{exts} / b_{extb})$

   in terms of percent change of visibility:

   $\Delta\% = (b_{exts} / b_{extsb}) \times 100$

Based on the predicted SO_4, NO_3, and PM_{10} concentrations, the proposed facility's emissions are compared to a 5 percent change in light extinction of the background levels. This is equivalent to a change in deciview of 0.5.

2.3 MODEL SELECTION

The California Puff (CALPUFF, Version 5.0) air modeling system was used to model JEA's proposed facility and assess visibility at the ONWR. CALPUFF is a non-steady state Lagrangian Gaussian puff long-range transport model that includes algorithms for building downwash effects as well as chemical transformations (important for visibility controlling pollutants), and wet/dry deposition. The CALMET model, a preprocessor to CALPUFF, is a diagnostic meteorological model that produces a three-dimensional field of wind and temperature and a two-dimensional field of other meteorological parameters. Simply, CALMET was designed to process raw meteorological, terrain, and land-use databases to be used in the air modeling analysis. The CALPUFF modeling system uses a number of FORTRAN preprocessor programs that extract data from large databases and converts the data into formats suitable for input to CALMET. The processed data produced from CALMET was input to CALPUFF to assess the pollutant specific impact. Both CALMET and CALPUFF were used in a manner that is recommended by the IWAQM Phase 2 Report.

2.4 CALPUFF MODEL SETTINGS

The CALPUFF settings contained in Table 2-2 were used for the refined modeling analysis. A detailed listing of parameter values used is presented in Table A-1 in Appendix A.

Table 2-2

CALPUFF Model Settings

Parameter	Setting
Pollutant Species	SO_2, SO_4, NO_x, HNO_3, and NO_3, and PM_{10}
Chemical Transformation	MESOPUFF II scheme
Deposition	Include both dry and wet deposition, plume depletion
Meteorological/Land Use Input	CALMET
Plume Rise	Transitional, Stack-tip downwash, Partial plume penetration
Dispersion	Puff plume element, PG /MP coefficients, rural mode, ISC building downwash scheme
Terrain Effects	Partial plume path adjustment
Output	Create binary concentration file including output species for SO_4, NO_3 and PM_{10}
Model Processing	Highest predicted 24-hour SO_4, NO_3 and PM_{10} concentrations for year
Background Values	Ozone: 60 ppb; Ammonia: 3 ppb

2.5 BUILDING WAKE EFFECTS

The CALPUFF analysis included the proposed facility's building dimensions to account for the effects of building-induced downwash on the emission sources. Dimensions for all significant building structures were processed with the Building Profile Input Program (BPIP), Version 95086, and were included in the CALPUFF model input. The Prevention of Significant Deterioration Air Permit Application for the Brandy Branch Facility submitted to FDEP by Black & Veatch on May 17, 1999 (hereinafter referred to as the PSD Application) presents a listing of all structures included in the analysis.

2.6 RECEPTOR LOCATIONS

The CALPUFF analysis used an array of discrete receptors at appropriate distances to ensure sufficient density and aerial extent to adequately characterize the pattern of pollutant impacts in the ONWR area. Specifically, the array consists of receptor spacing of 2 km beginning at a 50-km distance from the proposed facility location and continues to the farthest extent of the OWNR area. Because the terrain throughout the ONWR is flat, an elevation of zero was used for all receptors.

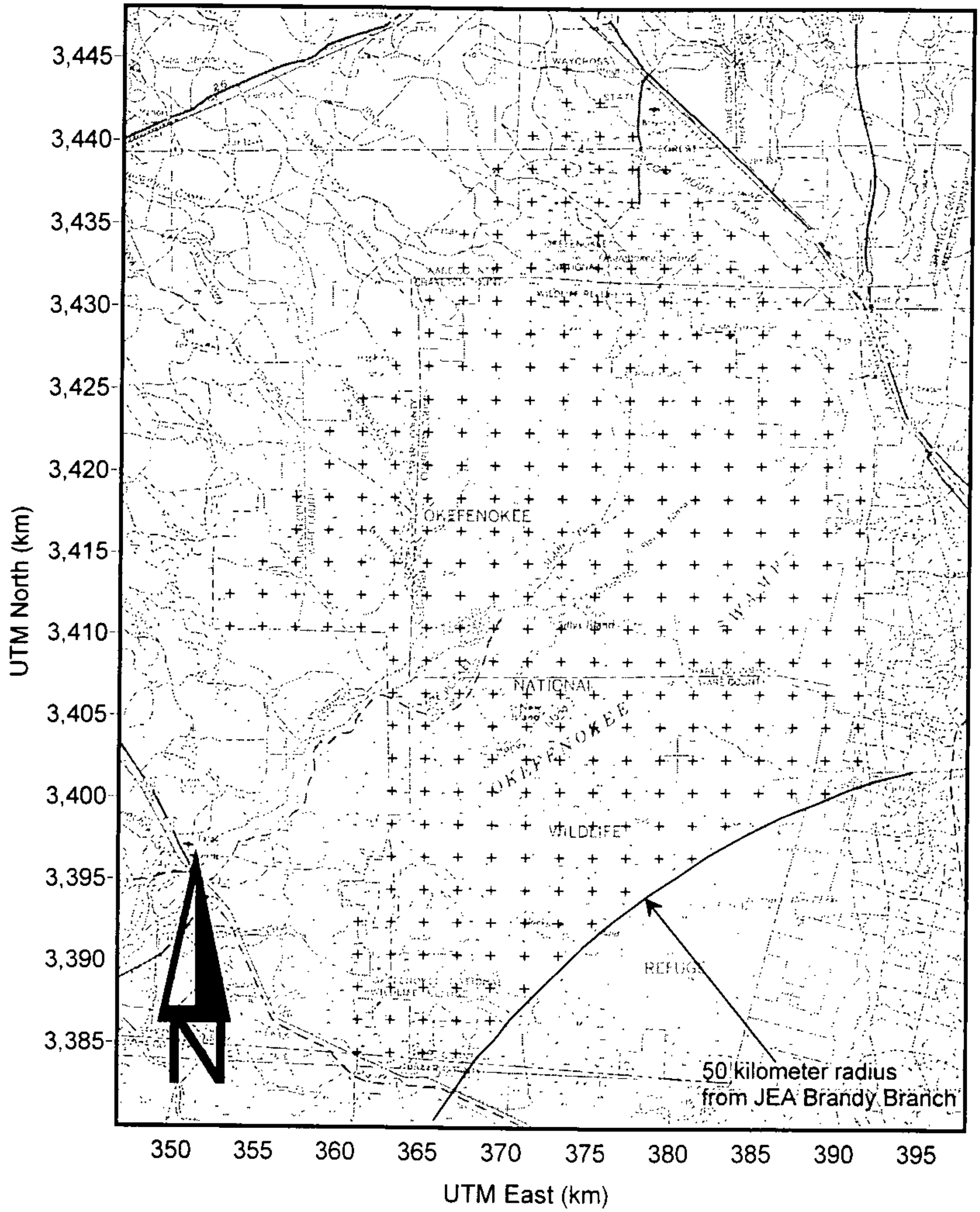
A map showing the locations of receptors used for the modeling analysis is presented in Figure 2-1.

2.7 BACKGROUND VISUAL RANGES AND RELATIVE HUMIDITY FACTORS

The background visual range is based on data representative of the top 20-percentile air quality days. The background visual range for the ONWR is 65 km and was provided by the FLM. The average relative humidity factor for each species' worst day was computed by determining the relative humidity factor for each hour's relative humidity for the 24-hour period that the maximum impact occurred. This factor, based on each relative humidity was estimated by using Figure B-1 of Appendix B of IWAQM Phase I Report (U.S. EPA 1993). These factors (a relative humidity factor for each relative humidity) were then used to determine the average relative humidity factor for that day (24-hour period).

2.8 METEOROLOGICAL DATA PROCESSING

The California Puff meteorological and geophysical data preprocessor (CALMET, Version 5) was used to develop the gridded parameter fields required for the refined regional haze modeling analysis. The follow sections discuss the specific data used and processed in the CALMET model.



JEA Brandy Branch
Dense 2 km Receptor Grid
for input into CALPUFF

Figure 2-1

Receptors.srf

2.8.1 CALMET SETTINGS

The CALMET settings contained in Table 2-3 were used for the refined modeling analysis. A detailed listing of parameter values used is presented in Table A-2 in Appendix A.

Table 2-3

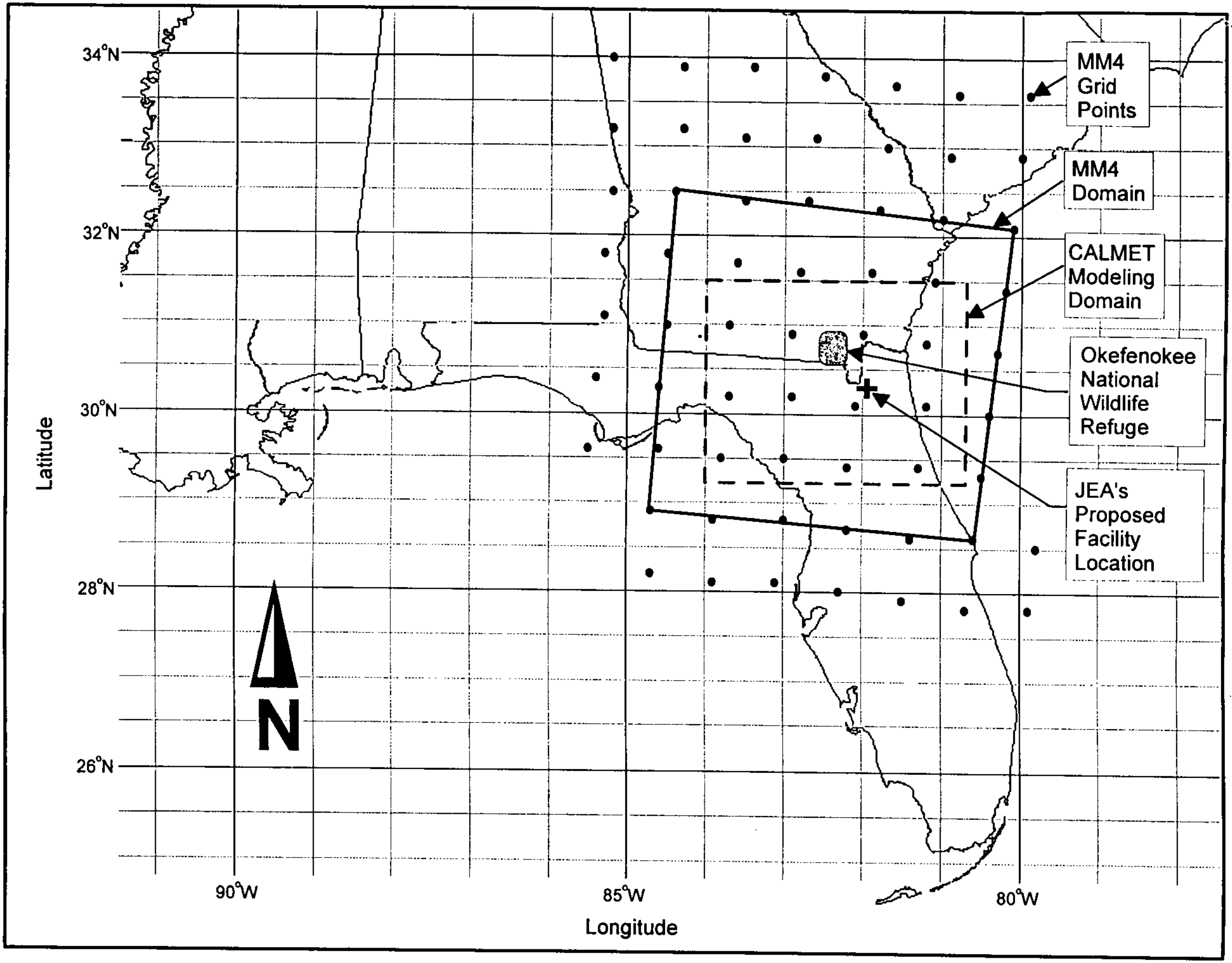
CALMET Settings

Parameter	Setting
Horizontal Grid Dimensions	325 by 250 km, 5 km grid resolution
Vertical Grid	8 layers
Weather Station Data Inputs	8 surface, 5 upper air, 35 precipitation stations
Wind model options	Diagnostic wind model, no kinematic effects
Prognostic wind field model	MM4 data, 80 km resolution, 6 x 6 grid, used for wind field initialization
Output	Binary hourly gridded meteorological data file for CALPUFF input

2.8.2 MODELING DOMAIN

A rectangular modeling domain extending 325 km in the east-west (x) direction and 250 km in the north-south (y) direction was used for the refined modeling analysis. The boundary of the domain is represented by the dashed line in Figure 2-2. The southwest corner of the domain is the origin and is located at 29.25 N degrees latitude and 84 W degrees longitude. This location is in the northeastern Gulf of Mexico approximately 140 km due south of Tallahassee. The size of the domain used for the modeling was based on the distances needed to cover the area from the proposed facility to the receptors at the ONWR with an 80-km buffer zone in each direction.

For the processing of meteorological and geophysical data, 65 grid cells were used in the x-direction and 50 grid cells were used in the y-direction. A 5-km grid spacing was used. The air modeling analysis was performed in the UTM coordinate system.



CALMET Domain

Figure 2-2

2.8.3 MESOSCALE MODEL – GENERATION 4 (MM4) DATA

Pennsylvania State University in conjunction with the NCAR Assessment Laboratory developed the MM4 data set, a prognostic wind field or "guess" field, for the United States. The hourly meteorological variables used to create this data set (wind, temperature, dew point depression, and geopotential height for eight standard levels and up to 15 significant levels) are extensive and only allow for one data base set for the year 1990. The analysis used the MM4 data to initialize the CALMET wind field. The MM4 data have a horizontal spacing of 80 km and are used to simulate atmospheric variables within the modeling domain.

To apply a national MM4 dataset to the modeling domain, a sub-set domain was developed that fully enclosed the area of the modeling domain. The MM4 subset domain consisted of a 6 x 6-cell rectangle, with 80 km grid resolution, extending from the MM4 grid points (49,13) to (54, 18). These data were processed to create a MM4.Dat file, for input to the CALMET model. The MM4 subset domain is represented by the solid line rectangle in Figure 2-2.

The MM4 data set used in the CALMET, although advanced, lacks the fine detail of specific temporal and spatial meteorological variables and geophysical data. These variables were processed into the appropriate format and introduced into the CALMET model through the additional data files obtained from the following sources.

2.8.4 SURFACE DATA STATIONS AND PROCESSING

The surface station data processed for the CALPUFF analyses consisted of data from eight National Weather Service (NWS) stations or Federal Aviation Administration (FAA) Flight Service stations for Jacksonville, Tallahassee, Gainesville, Tampa and Daytona Beach (FL) and Columbus, Macon and Savannah (GA). A summary of the surface station information and locations are presented in Table 2-4 and Figure 2-3, respectively. The surface station parameters include wind speed, wind direction, cloud ceiling height, opaque cloud cover, dry bulb temperature, relative humidity, station pressure, and a precipitation code that is based on current weather conditions.

The weather station data for all stations but Gainesville was downloaded for the year 1990 from the National Climatic Data Center's (NCDC) Solar and Meteorological Surface Observational Network (SAMSON) CD-ROM set. The surface data from Gainesville was processed from NCDC CD-144 format. The data was processed with the CALMET preprocessor utility program, SMERGE, to create one surface file, SURF.DAT.

2.8.5 UPPER AIR DATA STATIONS AND PROCESSING

The analysis included five upper air NWS stations located in Ruskin and Apalachicola (FL), Athens and Waycross (GA), and Charleston (SC). Data for these stations was obtained from the NCDC Radiosonde Data CD and processed into the NCDC Tape Deck (TD) 6201 format by the READ62 utility program for input to CALMET. The data and locations for the upper air stations are presented in Table 2-4 and Figure 2-3, respectively.

2.8.6 PRECIPITATION DATA STATIONS AND PROCESSING

Precipitation data was processed from a network of hourly precipitation data files collected from primary and secondary NWS precipitation recording stations located in southern Georgia and northern Florida. Data for 35 stations within or just beyond the modeling domain (dashed rectangular box in Figure 2-2) were obtained in NCDC TD-3240 variable format and converted into a fixed-length format. The utility programs PXTRACT and PMERGE were used to process the data into the format for the Precip.Dat file that is used by CALMET. A listing of the precipitation stations used for the modeling analysis is presented in Table 2-5.

2.8.7 GEOPHYSICAL DATA PROCESSING

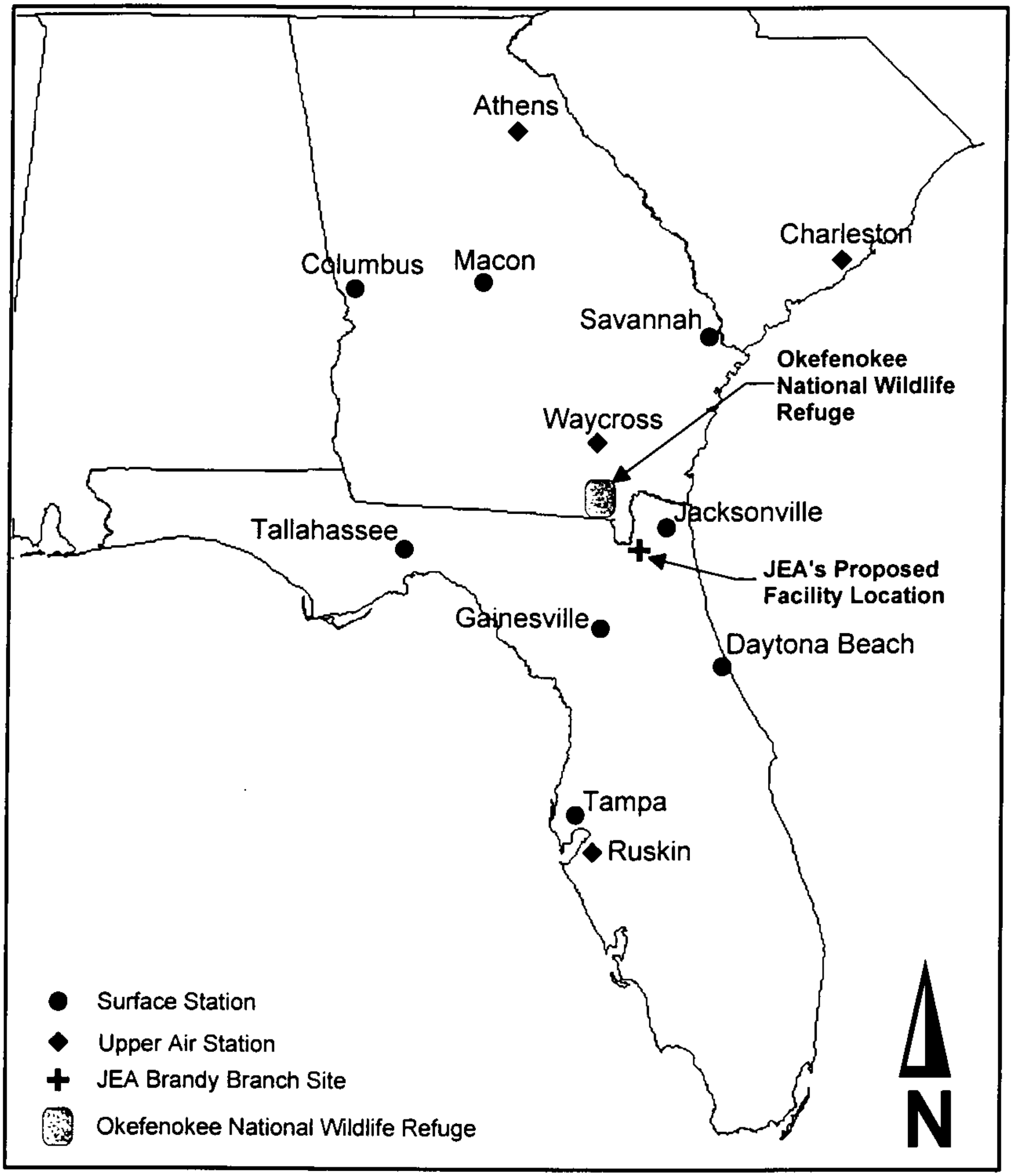
Terrain elevations for each grid cell of the modeling domain were obtained from Digital Elevation Model (DEM) files obtained from US Geographical Survey (USGS). The DEM data was extracted for the modeling domain grid using the utility extraction program LCELEV. Land-use data was obtained from the USGS GIS.DAT which is based on the ARM3 data. The resolution of the GIS.DAT file is one-eighth of a degree in the east-west direction and one-twelfth of a degree in the north-south direction. Land-use values for the domain grid were obtained with the utility program CAL-LAND. Other parameters processed for the modeling

Table 2-4

Surface and Upper Air Stations Used in the CALPUFF Analysis

Station Name	Station Symbol	WBAN Number	UTM Coordinates			Anemometer Height (m)
			Easting (km)	Northing (km)	Zone	
Surface Stations						
Tampa, FL	TPA	12842	349.17	3094.25	17	6.7
Jacksonville, FL	JAX	13889	432.82	3374.19	17	6.1
Daytona Beach, FL	DAB	12834	495.14	3228.09	17	9.1
Tallahassee, FL	TLH	93805	173.04[a]	3363.99	16	7.6
Columbus, GA	COL	93842	112.57[a]	3599.35	16	9.1
Macon, GA	MCN	03813	251.58	3620.93	17	7.0
Savannah, GA	SAV	03822	481.13	3555.03	17	9.1
Gainesville, FL	GNV	12816	377.43	3284.16	17	6.7
Upper Air Stations						
Ruskin, FL	TBW	12842	361.95	3064.55	17	NA
Waycross, GA	AYS	13861	366.68	3457.95	17	NA
Athens, GA	AHN	13873	285.91	3758.83	17	NA
Charleston, SC	CHS	13880	590.42	3640.42	17	NA
Apalachicola, FL	AQQ	12832	110.22	3290.65	17	NA

[a] Equivalent Coordinate for Zone 17



National Weather Service
Meteorological Surface & Upper Air Stations
Used in the CALMET Model

Figure 2-3

metstation.srf

Table 2-5

Hourly Precipitation Stations Used in the CALPUFF Analysis

Station Name	Station Number	UTM Coordinates		
		Easting (km)	Northing (km)	Zone
Florida				
Branford	80975	315.61	3315.96	17
Bristol	81020	113.72*	3366.47	16
Brooksville 7 SSW	81048	358.03	3149.55	17
Cross city 2 WNW	82008	290.27	3281.75	17
Daytona Beach WSO AP	82158	495.14	3228.09	17
Deland 1 SSE	82229	470.78	3209.66	17
Dowling Park 1 W	82391	283.51	3348.42	17
Gainesville 11 WNW	83322	354.85	3284.43	17
Inglis 3 E	84273	342.63	3211.65	17
Jacksonville WSO AP	84358	434.27	3372.40	17
Lakeland	84797	409.87	3099.18	17
Lisbon	85076	423.59	3193.26	17
Lynne	85237	409.26	3230.30	17
Marineland	85391	479.19	3282.03	17
Melbourne WSO	85612	534.38	3109.97	17
Monticello 3 W	85879	220.17	3381.29	17
Orlando WSO McCoy	86628	468.99	3146.88	17
Panacea 3 s	86828	172.45*	3319.61	16
Raiford State Prison	87440	385.93	3326.55	17
Saint Leo	87851	376.48	3135.09	17
Tallahassee WSO AP	88758	173.04*	3363.99	16
Woodruff Dam	89795	124.29*	3399.94	16
Georgia				
Abbeville 4 S	90010	281.84	3535.69	17
Bainbridge Intl Paper Co	90586	144.85*	3409.59	16
Brunswick	91340	452.34	3447.98	17
Coolidge	92238	226.34	3434.77	17
Doles	92728	226.73	3510.59	17
Edison	93028	135.13*	3494.43	16
Fargo	93312	349.92	3395.35	17
Folkston 3 SW	93460	401.13	3407.69	17
Hazlehurst	94204	348.49	3526.08	17
Jesup	94671	416.21	3498.08	17
Pearson	96879	325.50	3464.09	17
Richmond Hill	97468	468.92	3535.69	17
Valdosta 4 NW	98974	276.90	3416.95	17

* Equivalent Coordinate for Zone 17

domain by CAL-LAND include surface roughness, surface albedo, Bowen ratio, soil heat flux, and leaf index field. Once processed, all of the land-use parameters were combined with the terrain information into a GEO.DAT file for input to CALMET. The land-use parameter values were based on annual averaged values.

2.9 FACILITY EMISSIONS

Performance data for the simple cycle combustion turbines is based on vendor data from GE at design loads of 50, 75, and 100 percent, natural gas and distillate fuel firing, and ambient air temperatures of 20°F, 59°F, and 95°F. This data is presented in detail in the PSD Application.

The maximum pound per hour emission rates considering all ambient temperatures and partial load operation for natural gas and distillate fuel oil firing for the pollutants modeled with CALPUFF are presented in Table 2-6.

The emission rates used in the regional haze modeling analysis were developed from those rates in Table 2-6 by assuming the facility will operate 16 hours per day on distillate fuel oil and the remaining 8 hours of the day on natural gas. Table 2-7 presents the stack parameters and emission rates that were used in the CALPUFF analysis.

Table 2-6
Project Maximum Emission Rates (lb/h)*

Pollutant	Natural Gas Firing (lb/h)	Distillate Oil Firing (lb/h)
NO_x	84.8	338.0
SO_2	1.1	104.3
PM/PM_{10}	9.0	17.0

*Maximum pound per hour emission rates for the SCCTs considering average ambient temperature and partial load operation for natural gas and distillate fuel oil firing.

Table 2-7

Stack Parameters and Pollutant Emissions Used in the CALPUFF Analysis

Stack No.	Easting (m)	Northing (m)	Stack Heig ht (m)	Stack Diameter (m)	Exit Velocity (m/s)	Exit Temp (K)	Pollutant Emission Rate (g/s)		
							NO_x	SO_2	PM_{10}
1	408,835	3,354,491	27.4	5.49	46.27	848.7	31.95	8.82	1.80
2	408,774	3,354,491	27.4	5.49	46.27	848.7	31.95	8.82	1.80
3	408,713	3,354,491	27.4	5.49	46.27	848.7	31.95	8.82	1.80

*Assumes 16 hrs/day operation on fuel oil and 8 hrs/day on natural gas.

Example: NOx (338 lb/hr x (16 hrs/24 hrs)) + (84.8 lb/hr x (8 hrs/24 hrs)) = 253.6 lb/hr = 31.95 g/s

3.0 RESULTS

Table 3-1 summarizes the species' maximum impacts and predicted worst days for the refined visibility analysis. The predicted worst days (24-hour periods) for NO_3, PM_{10}, and SO_4 are 2/13 (Julian 44), 6/6 (Julian 157), and 8/26 (Julian 328), respectively. For each worst day, the hourly relative humidities and hourly relative humidity factors [f(RH)] were determined and are summarized in Table 3-2. The daily average f(RH)s for 2/13, 6/6 and 8/26 are 4.00, 4.26 and 4.26, respectively. The maximum predicted change due to the proposed facility operation for each worst day is summarized in Table 3-3. The maximum predicted change is 0.26 deciviews or 2.6 percent and occurs on 2/13. This impact is below the criteria of 0.5 deciviews or the 5 percent change indicating that the proposed facility operation does not adversely impact the existing regional haze at the ONWR.

Table 3-1
Maximum Predicted Species Concentrations at ONWR

Species Predicted	Maximum Concentration ($\mu g/m^3$)	Date	UTM Receptor Location	
			Easting (km)	Northing (km)
SO4	0.024999	26-Aug	377.278	3394.434
NO3	0.079068	13-Feb	391.278	3402.434
PM_{10}	0.054103	06-Jun	361.278	3386.434

Table 3-2

Computed Daily Average RH Factors for Predicted Worst Days[a]

Hour	February 13		June 6		August 26	
	RH(%)	f(RH)	RH(%)	f(RH)	RH(%)	f(RH)
100	93	8	90	6	88	5.5
200	93	8	93	8	85	4.7
300	93	8	93	8	85	4.7
400	96	13	93	8	91	6.2
500	93	8	97	14.5	94	9.5
600	93	8	93	8	94	9.5
700	93	8	87	5.3	94	9.5
800	89	5.7	79	3.4	88	5.5
900	80	3.5	70	2.3	70	2.3
1000	54	1.45	72	2.5	65	1.9
1100	49	1.3	65	1.9	52	1.4
1200	46	1.25	61	1.7	50	1.3
1300	43	1.2	63	1.75	49	1.3
1400	39	1.15	61	1.7	58	1.6
1500	39	1.15	61	1.7	58	1.6
1600	46	1.25	74	2.55	61	1.7
1700	50	1.3	74	2.55	65	1.9
1800	57	1.55	74	2.55	68	2
1900	63	1.75	77	2.9	74	2.55
2000	70	2.3	69	2.2	82	4
2100	73	2.5	74	2.55	82	4
2200	73	2.5	77	2.9	85	4.7
2300	73	2.5	85	4.7	88	5.5
2400	75	2.6	85	4.7	94	9.5
Average		4.00		4.26		4.26

[a]Hourly relative humidity data from Jacksonville, FL, 1990.

Table 3-3

CALPUFF Analysis Results

Item	Predicted Worst Days		
	44	157	238
Maximum Predicted Conc. ($\mu g/m^3$)			
PM_{10}	0.044962	0.054103	0.035216
SO_4	0.012144	0.022052	0.024999
NO_3	0.079068	0.033150	0.008253
Computed Concentrations ($\mu g/m^3$)			
$(NH_4)_2SO_4$	0.016698	0.030322	0.034374
NH_4NO_3	0.1020	0.0428	0.0106
Average Relative Humidity Factor[a]	4.00	4.26	4.26
Background Visual Range[b], Vr (km)	65	65	65
Background Extinction Coeff. (b_{extb}) (km^{-1})	0.0602	0.0602	0.0602
Source Extinction Coeff. (b_{exts}) (km^{-1})			
$(NH_4)_2SO_4$	0.000200	0.000388	0.000439
NH_4NO_3	0.001224	0.000547	0.000136
PM_{10}	0.000135	0.000162	0.000106
Total (b_{exts}) (km^{-1})	0.001559	0.001096	0.000681
Percent Change (%)	2.59	1.82	1.13
Deciview Change	0.256	0.181	0.113

[a]Computed from Jacksonville RH data.
[b]Provided by U.S. Fish and Wildlife Service.

APPENDIX A

Parameter Settings for:

CALPUFF

CALMET

Table A-1. IWAQM Phase II CALPUFF Parameter Settings Used in the Refined Regional Haze Analysis

Number	Input Group Description	Variable	Seq	Description	Default Value	Modeled Value
1	Run Control	METRUN	1	Do we run all periods (1) or a subset (0)?	0	0
1		IBYR	2	Beginning year	User Defined	90
1		IBMO	3	Beginning month	User Defined	1
1		IBDY	4	Beginning day	User Defined	6
1		IBHR	5	Beginning hour	User Defined	0
1		IRLG	5	Length of run (hours)	User Defined	Quarterly
1		NSPEC	6	Number of species modeled (for MESOPUFF II chemistry)	5	6
1		NSE	7	Number of species emitted	3	3
1		ITEST	8		2	2
1		MRESTART	9	Restart options (0 = no restart) allows splitting runs into smaller segments	0	0
1		NRESPD	10		0	0
1		METFM	11	Format of input meteorology (1 = CALMET, 2 = ISC)	1	1
1		AVET	12	Averaging time lateral dispersion parameters (minutes)	60	60
2	Tech Options	MGAUSS	1	Near-field vertical distribution (1 = Gaussian)	1	1
2		MCTADJ	2	Terrain adjustments to plume path (3 = Plume path)	3	3
2		MCTSG	3	Do we have subgrid hills? (0 = No) allows CTDM-like treatment for subgrid scale hills	0	0
2		MSLUG	4	Near-field puff treatment (0 = No slugs)	0	0
2		MTRANS	5	Model transitional plume rise? (1 = Yes)	1	1
2		MTIP	6	Treat stack tip downwash? (1 = Yes)	1	1
2		MSHEAR	7	Treat vertical wind shear? (0 = No)	0	1
2		MSPLIT	8	Allow puffs to split? (0 = No)	0	0
2		MCHEM	9	MESOPUFF-II Chemistry? (1 = Yes)	1	1
2		MWET	10	Model wet deposition? (1 = Yes)	1	1
2		MDRY	11	Model dry deposition? (1 = Yes)	1	1
2		MDISP	12	Method for dispersion coefficients (3 = PG & MP)	3	4

Table A-1. IWAQM Phase II CALPUFF Parameter Settings Used in the Refined Regional Haze Analysis

Input Group Number	Description	Variable	Seq	Description	Default Value	Modeled Value
2		MPARTL	16	Model partial plume penetration? (0 = No)	1	1
2		MTINV	17	Elevated inversion strength (0 = compute from data)	0	0
2		MPDF	18	Use PDF for convective dispersion? (0 = No)	0	0
2		MSGTIBL	19	Use TIBL module? (0 = No) allows treatment of subgrid scale coastal areas	0	0
2		MREG	20	Regulatory default checks? (1 = Yes)	1	0
3	Species List	CSPECn		Names of species modeled (for MESOPUFF II must be SO_2-SO4-NO_X-HNO3-NO3, PM_{10}	User Defined	ALL 6
3		Specie Groups		Grouping of species if any	User Defined	NA
3		Specie Names		Manner species will be modeled	User Defined	
4	Grid Control	NX	1	Number of east-west grids of input meteorology	User Defined	65
4		NY	2	Number of north-south grids of input meteorology	User Defined	50
4		NZ	3	Number of vertical layers of input meteorology	User Defined	8
4		DGRIDKM	4	Meteorology grid spacing (km)	User Defined	5
4		ZFACE	5	Vertical cell face heights of input meteorology	User Defined	9 values
4		XORIGKM	6	Southwest corner (east-west) of input User	Defined meteorology	208.46
4		YORIGIM	7	Southwest corner (north-south) of input User	Defined meteorology	3239.2
4		IUTMZN	8	UTM zone	User Defined	17
4		XLAT	9	Latitude of center of meteorology domain	User Defined	30
4		XLONG	10	Longitude of center of meteorology domain	User Defined	75
4		XTZ	11	Base time zone of input meteorology	User Defined	5
4		IBCOMP	12	Southwest X-index of computational domain	User Defined	1
4		JBCOMP	13	Southwest Y-index of computational domain	User Defined	1
4		IECOMP	14	Northeast X-index of computational domain	User Defined	65
4		JECOMP	15	Northeast Y-index of computational domain	User Defined	50

Table A-1. IWAQM Phase II CALPUFF Parameter Settings Used in the Refined Regional Haze Analysis

Input Group Number	Description	Variable	Seq	Description	Default Value	Modeled Value
4		IESAMP	19	Northeast X-index of receptor grid	User Defined	0
4		JESAMP	20	Northeast Y-index of receptor grid	User Defined	0
4		MESHDN	21	Gridded recpetor spacing = DGRIDKM/MESHDN	1	1
5	Output Options	ICON	1	Output concentrations? (1 = Yes)	1	1
5		IDRY	2	Output dry deposition flux? (1 = Yes)	1	0
5		IWET	3	Output west deposition flux? (1 = Yes)	1	0
5		IVIS	4	Output RH for visibility calculations (1 = Yes)	1	0
5		LCOMPRS	5	Use compression option in output? (T = Yes)	T	T
5		ICPRT	6	Print concentrations? (0 = No)	0	0
5		IDPRT	7	Print dry deposition fluxes (0 = No)	0	0
5		IWPRT	8	Print wet deposition fluxes (0 = No)	0	0
5		ICFRQ	9	Concentration print interval (1 = hourly)	1	24
5		IDFRQ	10	Dry deposition flux print interval (1 = hourly)	1	1
5		IWFRQ	11	West deposition flux print interval (1 = hourly)	1	1
5		IPRTU	12	Print output units (1 = g/m**3; g/m**2/s; 3 = ug/m3, ug/m2/s)	1	3
5		IMESG	13	Status messages to screen? (1 = Yes)	1	1
5		LDEBUG	14	Turn on debug tracking? (F = No)	F	F
5		NPFDEB	15	(Number of puffs to track)	(1)	1
5		NN1	16	(Met. Period to start output)	(1)	1
5		NN2	17	(Met. Period to end output)	(10)	10
7	Dry Dep Chem	Dry Gas Dep		Chemical parameters of gaseous deposition species	User Defined	NO_x,HNO3
						SO_2
8	Dry Dep Size	Dry Part. Dep		Chemical parameters of particulate deposition species	User Defined	SO4,NO3
						PM_{10}

Table A-1. IWAQM Phase II CALPUFF Parameter Settings Used in the Refined Regional Haze Analysis

Input Group Number	Description	Variable	Seq	Description	Default Value	Modeled Value
9		NINT	4	Number of particle-size intervals	9	9
9		IVEG	5	Vegetative state (1 = active and unstressed)	1	1
10	Wet Dep	Wet Dep		Wet deposition parameters	User Defined	Var
11	Chemistry	MOZ	1	Ozone background? (0 = constant background value; 1 = read from ozone.dat)	1	0
11		BCKO3	2	Ozone default (ppb) (Use only for missing data)	80	60
11		BCKNH3	3	Ammonia background (ppb)	10	3
11		RNITE1	4	Nighttime SO_2 loss rate (%/hr)	0.2	0.2
11		RNITE2	5	Nighttime NO_X loss rate (%/hr)	2	2
11		RNITE3	6	Nighttime HNO3 loss rate (%/hr)	2	2
12	Dispersion	SYTDEP	1	Horizontal size (m) to switch to time dependence	550	550
12		MHFTSZ	2	Use Heffter for vertical dispersion? (0 = No)	0	0
12		JSUP	3	PG Stability class above mixed layer	5	5
12		CONK1	4	Stable dispersion constant (Eq 2.7-3)	0.01	0.01
12		CONK2	5	Neutral dispersion constant (Eq 2.7-4)	0.1	0.1
12		TBD	6	Transition for downwash algorithms (0.5 = ISC)	0.5	0.5
12		IURB1	7	Beginning urban landuse type	10	10
12		IURB2	8	Ending urban landuse type	19	19
12		ILANDUIN	9	Land use type (20 = Unirrigated agricultural land)	(20)	20
12		ZOIN	10	Roughness length (m)	(0.25)	0.25
12		XLAIIN	11	Leaf area index	(3)	3
12		ELEVIN	12	Met. Station elevation (m above MSL)	(0)	0
12		XLATIN	13	Met. Station North latitude (degrees)	(-999)	-999
12		XLONIN	14	Met. Station West longitude (degrees)	(-999)	-999

Table A-1. IWAQM Phase II CALPUFF Parameter Settings Used in the Refined Regional Haze Analysis

Input Group Number	Description	Variable	Seq	Description	Default Value	Modeled Value
12		XMXLEN	18	Maximum slug length in units of DGRIDKM	1	1
12		XSAMLEN	19	Maximum puff travel distance per sampling step (units of DGRIDKM)	1	1
12		MXNEW	20	Maximum number of puffs per hour	99	99
12		MXSAM	21	Maximum sampling steps per hour	99	99
12		NCOUNT	22	Iterations when computing Transport Wind (Calmet & Profile Winds)	(2)	2
12		SYMIN	23	Minimum lateral dispersion of new puff (m)	1	1
12		SZMIN	24	Minimum vertical dispersion of new puff (m)	1	1
12		SVMIN	25	Array of minimum lateral turbulence (m/s)	6 * 0.50	6*0.50
12		SWMIN	26	Array of minimum vertical turbulence (m/s)	0.20,0.12,0.08,0.06,0.03,0.016	SAME
12		CDIV (1), (2)	27	Divergence criterion for dw/dz (1/s)	0.01 (0.0,0.0)	0.0,0.0
12		WSCALM	28	Minimum non-calm wind speed (m/s)	0.5	0.5
12		XMAXZI	29	Maximum mixing height (m)	3000	3000
12		XMINZI	30	Minimum mixing height (m)	50	50
12		WSCAT	31	Upper bounds 1st 5 wind speed classes (m/s)	1.54,3.09,5.14,8. 23,10.8	SAME
12		PLX0	32	Wind speed power-law exponents	0.07,0.07,0.10,0.15,0.35,0.55	SAME
12		PTGO	33	Potential temperature gradients PG E and F (deg/km)	0.020,0.035	SAME
12		PPC	34	Plume path coefficients (only if MCTADJ = 3)	0.5,0.5,0.5,0.5,0.35,0.35	SAME
12		SL2PF	35	Maximum Sy/puff length	10	10
12		NSPLIT	36	Number of puffs when puffs split	3	3
12		IRESPLIT	37	Hours when puff are eligible to split	User Defined	HR 17=1
12		ZISPLIT	38	Previous hour's mixing height(minimum)(m)	100	100
12		ROLDMAX	39	Previous Max mix ht/current mix ht ratio must be less then this value for puff to split	0.25	0.25
12		EPSSLUG	40	Convergence criterion for slug sampling integration	1.00E-04	1.0E-04
12		EPSAREA	41	Convergence criterion for area source integration	1.00E-06	1.0E-06
13	Point Source	NPT1	1	Number of point sources	User Defined	5

Table A-1. IWAQM Phase II CALPUFF Parameter Settings Used in the Refined Regional Haze Analysis

Input Group Number	Description	Variable	Seq	Description	Default Value	Modeled Value
13		Point Sources		Point sources characteristics	User Defined	VAR
14	Area Source	Area Sources		Area sources characteristics	User Defined	NA
15	Volume Source	Volume		Volume sources characteristics	User Defined Sources	NA
16	Line Source	Line Sources		Buoyant lines source characteristics	User Defined	NA
17	Receptors	NREC		Number of user defined receptors	User Defined	358
17		Receptor Data		Location and elevation (MSL) of receptors	User Defined	VAR
Legend						
	DEPOS.	With Deposition				
	DEFAULT	Uses defaults				
	VAR	Variable Input				
	NA	Not Applicable				
	SAME	Same as recommended				

Table A-2. IWAQM Phase II CALMET Option Settings Used in the Refined Regional Haze Analysis

Variable	Description	Default Value	Modeled Value
NSSTA	Number of stations in SURF.DAT file	User Defines	8
NPSTA	Number of stations in PRECIP.DAT	User Defines	35
ICLOUD	Is cloud data to be input as gridded fields? (0 = No)	0	0
IFORMS	Format of surface data (2 = formatted)	2	2
IFORMP	Format of precipitation data (2 = formatted)	2	2
IFORMC	Format of cloud data (2 = formatted)	2	0
IWFCOD	Generate winds by diagnostic wind module? (1 = Yes)	1	1
IFRADJ	Adjust winds using Froude number effects? (1 = Yes)	1	1
IKINE	Adjust winds using kinematic effects? (1 = Yes)	0	0
IOBR	Use O'Brien procedure for vertical winds? (0 = No)	0	0
ISLOPE	Compute slope flows? (1 = Yes)	1	1
IEXTRP	Extrapolate surface winds to upper layers? (-4 = use similarity theory and ignore layer 1 of upper air station data)	-4	-4
ICALM	Extrapolate surface calms to upper layers? (0 = No)	0	0
BIAS	Surface/upper-air weighting factors (NZ values)	NZ*0	-1, -.25, 6*0
IPROG	Using prognostic or MM-FDDA data? (0 = No)	4	4
LVARY	Use varying radius to develop surface winds?	F	F
RMAX1	Max surface over-land extrapoolation radius (km)	User Defines	10
RMAX2	Max aloft over-land extrapolation radius (km)	User Defines	50
RMAX3	Maximum over-water extrapolation radius (km)	User Defines	500
RMIN	Minimum extrapolation radius (km)	0.1	0.1
RMIN2	Distance (km) around an upper air site where veritcal extrapolation is excluded (Set to -1 if IEXTRP = +/-4)	4	4
TERRAD	Radius of influence of terrain features (km)	User Defines	10
R1	Relative weight at surface of Step 1 field and obs	User Defines	10
R2	Relative weight aloft of Step 1 field and obs	User Defines	25

Table A-2. IWAQM Phase II CALMET Option Settings Used in the Refined Regional Haze Analysis

Variable	Description	Default Value	Modeled Value
NINTR2	Max number of stations for interpolations (NZ values)	99	99
CRITFN	Critical Froude number	1	1
ALPHA	Empirical factor triggering kinematic effects	0.1	0.1
IDIOPT1	Compute temperatures from observations (0 = True)	0	0
ISURFT	Surface station to use for surface temperature (between 1 and NSSTA)	User Defines	2
IDIOPT2	Compute domain-average lapse rates? (0 = True)	0	0
IUPT	Station for lapse rates (between 1 and NUSTA)	User Defines	2
ZUPT	Depth of domain-average lapse rate (m)	200	200
IDIOPT3	Compute internally initial guess winds? (0 = True)	0	0
IUPWND	Upper air station for domain winds (-1 = 1/ r**2 interpolation of all stations)	-1	-1
ZUPWND	Bottom and top of layer for 1st guess winds (m)	1, 1000	1, 1000
IDIOPT4	Read surface winds from SURF.DAT? (0 = True)	0	0
IDIOPT5	Read aloft winds from UPn.DAT? (0 = True)	0	0
CONSTB	Neutral mixing height B constant	1.41	1.41
CONSTE	Convective mixing height E constant	0.15	0.15
CONSTN	Stable mixing height N constant	2400	2400
CONSTW	Over-water mixing height W constant	0.16	0.16
FCORIOL	Absolute value of Coriolis parameter	1.00E-04	1.00E-04
IAVEXZI	Spatial averaging of mixing heights? (1 = True)	1	1
MNMDAV	Max averaging radius (number of grid cells)	1	1
HAFANG	Half-angle for looking upwind (degrees)	30	30
ILEVZI	Layer to use in upwind averaging (between 1 and NZ)	1	6
DPTMIN	Minimum capping potential temperature lapse rate	0.001	0.001
DZZI	Depth for comuting capping lapse rate (m)	200	200
ZIMIN	Minimum over-land mixing height (m)	50	50
ZIMAX	Maximum over-land mixing height (m)	3000	3000

Table A-2. IWAQM Phase II CALMET Option Settings Used in the Refined Regional Haze Analysis

		Default	Modeled
Variable	Description	Value	Value
TRADKM	Radius of temperature interpolation (km)	500	500
NUMTS	max number of station in temperature interpolations	5	5
IAVET	Conduct spatial averaging of temperature? (1 = True)	1	1
TGDEFB	Default over-water mixed layer lapse rate (K/m)	-0.0098	-0.0098
TGDEFA	Default over-water capping lapse rate (K/m)	-0.0045	-0.0045
JWAT1	Beginning landuse type defining water	999	50
JWAT2	Ending landuse type defining water	999	50
NFLAGP	Method for precipitation interpolation (2 = 1/r**2)	2	2
SIGMAP	Precip radius for interpolations (km)	100	100
CUTP	Minimum cut off precip rate (mm/hr)	0.01	0.01
SSn	NSSTA input records for surface stations	User Defines	8
USn	NUSTA input records for upper-air stations	User Defines	5
PSn	NPSTA input records for precipation stations	User Defines	35
Legend			
DEFAULT	Uses defaults		
VAR	Variable Input		
NA	Not Applicable		
SAME	Same as recommended		

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NOTICE OF FINAL PERMIT

In the Matter of an
Application for Permit by:

Walter P. Bussells, Chief Executive Officer
Jacksonville Electric Authority
21 West Church Street
Jacksonville, Florida 32202-3139

DEP File No. 0310485-001-AC, PSD-FL-267
Brandy Branch Facility
Duval County

Enclosed is Final Permit Number 0310485-001-AC. This permit authorizes Jacksonville Electric Authority to construct the Brandy Branch facility. This permit is issued pursuant to Chapter 403, Florida Statutes.

Any party to this order has the right to seek judicial review of it under section 120.68 of the Florida Statutes, by filing a notice of appeal under rule 9.110 of the Florida Rules of Appellate Procedure with the clerk of the Department of Environmental Protection in the Office of General Counsel, Mail Station #35, 3900 Commonwealth Boulevard, Tallahassee, Florida, 32399-3000, and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The notice must be filed within thirty days after this order is filed with the clerk of the Department.

Executed in Tallahassee, Florida.

CHFancy

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

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Notice of Final Permit (including the Final permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 10-14-99 to the person(s) listed:

Walter P. Bussells, JEA *
N. Bert Gianazza, P.E., JEA
Gregg Worley, EPA
John Bunyak, NPS
Chris Kirts, NED
James L. Manning, P.E. RESD
Anthony L. Compaan, Black & Veatch

Clerk Stamp

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

______ (Clerk)   10-14-99 (Date)

FINAL DETERMINATION

JEA
Brandy Branch/Baldwin City
DEP File No.0310485, PSD-FL-267

The Department distributed a public notice package on August 12, 1999 to allow the applicant to construct a new plant known as the Brandy Branch Facility located at Baldwin City, Duval County. The Public Notice of Intent to Issue was published in The Florida Times-Union on August 23, 1999.

COMMENTS/CHANGES

Comments were received from EPA by letter and facsimile correspondence dated September 10, 1999.

Comments were received from the Fish and Wildlife Service by letter dated August 30, 1999.

Comments were received from the applicant by electronic correspondences dated August 27 and September 24, 1999. Additionally, the Department received comments from the applicant requesting that the wording on the Public Notice be revised to reflect a maximum number of operating hours of 4750 of which 750 could be on oil. The Department agreed to the Public Notice change and will address the substantive issue herein.

EPA and the applicant commented on the Technical Evaluation and Preliminary Determination (TEPD), the BACT and the DRAFT Permit. The comments related to the BACT and permit are summarized below and the Department's responses are included following each comment. Comments related to the TEPD are noted and maintained in the file.

The Fish and Wildlife Service as well as the EPA commented on the need for CALPUFF modeling for visibility and regional haze in the (Class I) Okefenokee area. The applicant submitted this modeling on September 10, 1999 and (as indicated by FWS) the shutting down of the applicant's Southside Station along with the permitting of this new facility will cause a net benefit to visibility. A cumulative analysis. modeling all increment-consuming sources in the area, predicted SO_2 exceedances, which were not significantly contributed to by this facility. FDEP will investigate the matter to determine which sources are contributing significantly to the exceedances and develop possible remedies for further consideration..

DRAFT Permit Administrative Requirements:

The applicant requested that the requirements listed as Conditions 6. and 7. ("Expiration" and "BACT Determination") be removed due to the inapplicability of 40 CFR 52.21 in the State of Florida.

RESPONSE: These conditions will remain, with changes to the referenced citations associated with these conditions.

DRAFT Permit Specific Conditions:

1. *Specific Condition 4*: The applicant requested that the permit reflect the applicant's ability to install (optional) evaporative inlet cooling.

RESPONSE: The requested change will be accommodated, as this option was referenced in the Technical evaluation.

2. *Specific Condition 7*: The applicant requested that parenthesis be placed around the words "No. 2 or superior grade of distillate oil".

RESPONSE: The requested change will not be accommodated due to the possible inference that the adjective "superior" applies only to the grade of oil (No. 2) and not the sulfur content.

3. *Specific Condition 8*: The applicant requested that a permitting note be placed at the end of the condition, clarifying the Department's position on the purpose of heat input values.

RESPONSE: The following language is added to the end of the condition, as has been done in other permitting actions: {Permitting note: The heat input limitations have been placed in the permit to identify the capacity of each emissions unit for purposes of confirming that emissions testing is conducted within 95-100 percent of the emissions unit's rated capacity (or to limit future operation to 105 percent of the test load), to establish appropriate limits and to aid in determining future rule applicability......}

4. *Specific Condition 13*: The applicant requested that the condition be reworded to clearly indicate total hours of permitted use and to be consistent with all modeling. Additionally, the EPA indicated a lack of clarity in hours of operation per combustion turbine and recommended that the use of the words "a calendar year" be replaced so as to be consistent with other permit conditions.

RESPONSE: The permit condition is reworded as follows: 13. Maximum allowable hours: Each stationary gas turbine shall only operate up to 4750 hours during any consecutive twelve month period, of which 750 hours of operation per combustion turbine may be while firing oil. Additionally, each turbine shall be limited to 16 hours per day of oil firing. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

5. *Specific Conditions 14 and 15*: The applicant requested that these conditions be deleted. The EPA commented that limits should be on an individual combustion turbine basis. These conditions had required facility-wide fuel usage monitoring and reporting on a monthly basis.

RESPONSE: The aforementioned permit conditions are deleted as the newly worded Specific Condition 13 dictates a precise (and different) method of compliance per combustion turbine.

6. *Specific Condition 17*: The applicant requested that this condition be deleted. The EPA commented that the related NOx limits should be lower and have shorter compliance times.

RESPONSE: This condition requires that the units be constructed so as to be easily capable of accommodating an SCR should one be required in order to meet the NOx limits. Given that the applicant initially requested a NOx limit of 12 ppm and that the Department has imposed a more stringent limit of 10.5 ppm, this condition will not be deleted.

7. *Specific Condition 20*: The applicant requested language changes to accurately reflect the purpose and basis of the chart, noting that a BACT analysis was not required for VOC.

RESPONSE: A note will be added below the chart indicating that the VOC limit was not determined by BACT.

8. *Specific Condition 21*: The EPA suggested that the limits imposed by the second "bullet" be more stringent. The EPA additionally commented on the applicability of SCR (as discussed in the BACT) questioning several of the applicant's assumptions (through its comments 4., 5. and 6.). The applicant requested that the condition imposed by the fourth "bullet" (requirement to evaluate lower NOx emissions while firing oil) be deleted or reworded.

RESPONSE: The limits imposed by the second bullet are related to NOx emissions while firing natural gas. The Department appreciates the concerns raised by the EPA, but believes that extenuating circumstances are involved. Namely, these are:

1) The applicant has proposed to shutdown an existing facility (Southside) in an effort to offset most air emission-related issues. The result should yield a net reduction of regulated pollutants emitted on an annual basis.
2) By imposing a limit of 10.5 ppm (versus 12 ppm as proposed by the applicant), the Department estimates that the net NOx emissions of the combined actions noted above are approximately zero TPY. Further mandated NOx reductions may be viewed as punitive.
3) In order to accommodate the applicant's concern about their ability to routinely achieve this lower imposed limit as well as the applicant's action noted in 1) above, the Department believes that a compliance method which is more flexible than is normally required can be allowed.

Therefore, the limits imposed by the second bullet will not be changed. However, the BACT will incorporate these extenuating circumstances as a part of the Department's justification. Concerning the applicant's request on the fourth "bullet", the wording will be revised in a fashion similar to that proposed by the applicant.

9. *Specific Condition 22*: The applicant requested that EPA method 10 be clearly indicated as the method of compliance for both the concentration and lb/hr limit of CO emissions. The applicant additionally noted that vendor guarantees for CO have only been obtained at the 15 ppm level, versus the 12 ppm level identified in the draft BACT. The applicant indicated that reasonable assurance for a 12 ppm emission rate cannot be provided and requested the ability to evaluate a lower limit (via testing and analysis) after the initial (15 ppm) acceptance test and subsequent testing is completed.

RESPONSE: Language similar to that proposed by the applicant for EPA Method 10 will be added. Concerning the CO limit, permit language will be included (similar to what is shown in Specific Condition 21 (fourth bullet)) including an "initial" 15 ppm limit with a requirement to submit an evaluation to FDEP concerning a lower limitation.

10. *Specific Condition 24*: The EPA requested that the permit conditions should list the corresponding particulate matter emissions rate limit even though opacity will be used as the method of compliance. Additionally, the EPA questioned the allowance of 20% opacity during startup and shutdown, noting that FDEP routinely permits combustion turbines without this "automatic" allowance.

RESPONSE: The Department agrees with EPA and will revise this condition accordingly.

11. *Specific Condition 26*: The applicant requested that an assumed typographical error be corrected in this condition.

RESPONSE: The typographical error will be corrected.

12. *Specific Condition 27*: The applicant requested that compliance-related notifications should be made to RESD and not duplicated to the Department. Additionally, the applicant requested that the condition be revised to accurately reflect Rule 62-210.700(6), F.A.C.

RESPONSE: Administrative Requirement number 13 as well as Specific Conditions 6, 27, 35, 37 and 41 will be re-worded to accurately reflect the Department's intent regarding compliance-related notifications. Specific Condition 27 will be revised to accurately reflect Rule 62-210.700(6), F.A.C.

13. *Specific Condition 29*: The applicant requested a revision to this condition clarifying the Department's intent concerning initial testing on oil as well as shake-down testing.

RESPONSE: Language similar to that proposed by the applicant will be added for initial testing on oil. However, the condition will not be revised in such a manner to allow routine or repetitive shakedown periods after the initial 100 days of operation.

14. *Specific Condition 30*: The applicant requested a revision to this condition eliminating reference to SCR controls and clarifying the Department's intent concerning 3-hr and 24-hr averaging times for NOx compliance.

RESPONSE: The Department will clarify its intent. However, the Department intends to allow for the possibility of SCR controls to be installed as indicated in prior discussion above.

15. *Specific Condition 31*: The applicant requested a revision to this condition so as to have similar language to other permits regarding the sulfur content of natural gas.

RESPONSE: The Department will modify the language so as to replicate other permits.

16. *Specific Condition 33*: The applicant requested a revision to this condition so as to eliminate the reference to the VOC limit having been determined by BACT.

RESPONSE: The Department will eliminate this reference in this condition.

17. *Specific Condition 40*: The applicant requested a revision to this condition to be consistent with its request in item 4. above.

RESPONSE: The Department will revise this condition so as to provide a means of compliance with the newly worded permit conditions (concerning hours of operation per CT).

18. *Specific Condition 41*: The applicant requested that this condition be revised so as to eliminate the last sentence or (at a minimum) to eliminate the words "and fuel switching".

RESPONSE: The Department will eliminate the words "and fuel switching".

19. *Specific Condition 43*: The applicant requested that this condition be revised so as to be consistent with other similar permitting actions.

RESPONSE: The Department will comply with this request.

20. *Specific Condition 45*: The applicant requested that this condition be revised for clarity so as to indicate when an Acid Rain permit should be applied for.

RESPONSE: The Department will comply with this request.

CONCLUSION

The final action of the Department is to issue the permit with the changes described above.

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

PERMITTEE:

Jacksonville Electric Authority
Brandy Branch Facility
21 West Church Street
Jacksonville, Florida 32202-3139
Authorized Representative:

Walter P. Bussells, Chief Executive Officer

File No.	PSD-FL-267
FID No.	0310485
SIC No.	4911
Expires:	12/31/02

PROJECT AND LOCATION:

Permit pursuant to the requirements for the Prevention of Significant Deterioration of Air Quality (PSD Permit) for the construction of: three dual-fuel nominal 170 megawatt (MW) General Electric PG7241FA combustion turbine-electrical generators and three 90-foot stacks. The units will operate in simple cycle mode and intermittent duty. The units will be equipped with Dry Low NO_X (DLN-2.6) combustors and wet injection capability. They are designated by JEA as Combustion Turbine Generators 1, 2 and 3 and by the Department as ARMS Emissions Units 001, 002 and 003.

The project will be located approximately 1 mile N.E. of Baldwin City, Duval County. UTM coordinates are: Zone 17; 408.81 km E; 3354.38 km N.

STATEMENT OF BASIS:

This PSD permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), and Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.) and 40CFR51.166. The above named permittee is authorized to modify the facility in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department of Environmental Protection (Department).

Attached Appendices and Tables made a part of this permit:

Appendix BD	BACT Determination
Appendix GC	Construction Permit General Conditions

for Howard L. Rhodes, Director
Division of Air Resources Management

SECTION I. FACILITY INFORMATION

FACILITY DESCRIPTION

This facility is a new site. This permitting action is to install three dual-fuel nominal 170 megawatt (MW) General Electric PG7241FA combustion turbine-electrical generators with three 90-foot stacks and three fuel oil storage tanks.

Emissions from the new units will be controlled by Dry Low NO_X (DLN-2.6) combustors when operating on natural gas and wet injection when firing fuel oil. Inherently clean fuels and good combustion practices will be employed to control all pollutants.

EMISSION UNITS

This permit addresses the following emission units:

ARMS Emissions Unit	System	Emission Unit Description
001	Power Generation	One nominal 170 Megawatt Gas Simple Cycle Combustion Turbine-Electrical Generator
002	Power Generation	One nominal 170 Megawatt Simple Cycle Gas Combustion Turbine-Electrical Generator
003	Power Generation	One nominal 170 Megawatt Simple Cycle Gas Combustion Turbine-Electrical Generator
004	Fuel Storage	1 Million Gallon Fuel Oil Storage Tank
005	Fuel Storage	1 Million Gallon Fuel Oil Storage Tank
006	Fuel Storage	1 Million Gallon Fuel Oil Storage Tank

REGULATORY CLASSIFICATION

The facility is classified as a Major or Title V Source of air pollution because emissions of at least one regulated air pollutant, such as particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), nitrogen oxides (NO_X), carbon monoxide (CO), or volatile organic compounds (VOC) exceeds 100 tons per year (TPY).

This facility is not within an industry included in the list of the 28 Major Facility Categories per Table 212.400-1, F.A.C. Because emissions are greater than 100 TPY for at least one criteria pollutant, the facility is also a Major Facility with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD). Pursuant to Table 62-212.400-2, modifications at this facility resulting in emissions increases greater than any of the following values require review per the PSD rules as well as a determination of Best Available Control Technology (BACT): 40 TPY of NO_X, SO_2, or VOC; 25/15 TPY of PM/PM_{10}; 100 TPY of CO; or 7 TPY of sulfuric acid mist (SAM). This facility and the project are also subject to applicable provisions of Title IV, Acid Rain, of the Clean Air Act.

SECTION I. FACILITY INFORMATION

PERMIT SCHEDULE

- 08/23/99 Notice of Intent published in The Florida Times-Union
- 08/12/99 Distributed Intent to Issue Permit
- 08/06/99 Application deemed complete
- 05/18/99 Received Application

RELEVANT DOCUMENTS:

The documents listed below are the basis of the permit. They are specifically related to this permitting action, but not all are incorporated into this permit. These documents are on file with the Department.

- Application received on May 18, 1999
- Department letters dated May 26 and July 21, 1999
- Comments from the Fish and Wildlife Service dated July 20, August 12 and August 30, 1999
- Letter from JEA dated June 21, 1999
- Letter (e-mail) from JEA dated August 4, 1999 and related submittals
- Department's Intent to Issue and Public Notice Package dated August 12, 1999
- Letters (e-mail) from JEA dated August 27 and September 24, 1999
- Letter (facsimile) from EPA dated September 10, 1999
- Letter from Golder Associates Inc. dated September 10, 1999 and regional haze analysis
- Department's Final Determination and Best Available Control Technology Determination issued concurrently with this permit.

SECTION II. ADMINISTRATIVE REQUIREMENTS

1. Regulating Agencies: All documents related to applications for permits to construct, operate or modify an emissions unit should be submitted to the Bureau of Air Regulation (BAR), Florida Department of Environmental Protection (FDEP), at 2600 Blair Stone Road, Tallahassee, Florida 32399-2400 and phone number (850) 488-1344. All documents related to reports, tests, and notifications should be submitted to the DEP Northeast District office, 7825 Baymeadows Way, Suite 200B, Jacksonville, Florida 32256 and phone number 904/448-4300; additionally, such documents shall be submitted to RESD, Suite 225, 117 W. Duval St., Jacksonville, Florida 32202 and phone number 904/630-3484.
2. General Conditions: The owner and operator is subject to and shall operate under the attached General Permit Conditions G.1 through G.15 listed in Appendix GC of this permit. General Permit Conditions are binding and enforceable pursuant to Chapter 403 of the Florida Statutes. [Rule 62-4.160, F.A.C.]
3. Terminology: The terms used in this permit have specific meanings as defined in the corresponding chapters of the Florida Administrative Code.
4. Forms and Application Procedures: The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. [Rule 62-210.900, F.A.C.]
5. Modifications: The permittee shall give written notification to the Department when there is any modification to this facility. This notice shall be submitted sufficiently in advance of any critical date involved to allow sufficient time for review, discussion, and revision of plans, if necessary. Such notice shall include, but not be limited to, information describing the precise nature of the change; modifications to any emission control system; production capacity of the facility before and after the change; and the anticipated completion date of the change. [Chapters 62-210 and 62-212]
6. Expiration: Approval to construct shall become invalid if construction is not commenced within 18 months after receipt of such approval, or if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified. [62-4.070(4), 62-4.210(2)&(3), 62-210.300(1)(a)].
7. BACT Determination: In accordance with paragraph (4) of 40 CFR 51.166(j) the Best Available Control Technology (BACT) determination shall be reviewed and modified as appropriate in the event of a plant conversion. This paragraph states: "For phased construction projects, the determination of best available control technology shall be reviewed and modified as appropriate at the latest reasonable time which occurs no later than 18 months prior to commencement of construction of each independent phase of the project. At such time, the owner or operator of the applicable stationary source may be required to demonstrate the adequacy of any previous determination of best available control technology for the source." This reassessment will also be conducted for this project if there are any increases in heat input limits, hours of operation, oil firing, low or baseload operation (e.g. conversion to combined-

SECTION II. ADMINISTRATIVE REQUIREMENTS

cycle operation) short-term or annual emission limits, annual fuel heat input limits or similar changes. [40 CFR 51.166, Rule 62-4.070 F.A.C.]

8. Application for Title V Permit: An application for a Title V operating permit, pursuant to Chapter 62-213, F.A.C., must be submitted to the DEP's Bureau of Air Regulation, and a copy to the Department Northeast District office as well as RESD. [Chapter 62-213, F.A.C.]

9. New or Additional Conditions: Pursuant to Rule 62-4.080, F.A.C., for good cause shown and after notice and an administrative hearing, if requested, the Department may require the permittee to conform to new or additional conditions. The Department shall allow the permittee a reasonable time to conform to the new or additional conditions, and on application of the permittee, the Department may grant additional time. [Rule 62-4.080, F.A.C.]

10. Annual Reports: Pursuant to Rule 62-210.370(2), F.A.C., Annual Operation Reports, the permittee is required to submit annual reports on the actual operating rates and emissions from this facility. Annual operating reports shall be sent to the DEP's Northeast District office as well as RESD by March 1st of each year. [Rule 62-210.370(2), F.A.C.]

11. Stack Testing Facilities: Stack sampling facilities shall be installed in accordance with Rule 62-297.310(6), F.A.C.

12. Permit Extension: The permittee, for good cause, may request that this construction permit be extended. Such a request shall be submitted to the Bureau of Air Regulation prior to 60 days before the expiration of the permit [Rule 62-4.080, F.A.C.]

13. Quarterly Reports: Quarterly excess emission reports, in accordance with 40 CFR 60.7 (a)(7) (c) (1997 version), shall be submitted to RESD. Each excess emission report shall include the information required in 40 CFR 60.7(c) and 60.334.

14. Retirement of existing facility: In accordance with JEA's analyses of regional haze in the nearby Class I areas, the Brandy Branch facility may cause or contribute to haze values greater than 5%. In order to mitigate this possibility, JEA will limit the operation of the combustion turbines permitted herein to a maximum of 16 hours per day of oil operation. Additionally, so as to cause a net benefit to the nearby Class I areas, JEA shall retire the existing Southside Facility (AIRS ID 0310046) located at 801 Colorado Avenue, Jacksonville, Florida upon JEA's application for a Title V permit for the Brandy Branch facility (including certification that the facility is in compliance with applicable requirements and permit conditions). JEA shall concurrently submit a letter from the designated representative of the Southside facility certifying that the facility has been shutdown and that related permits are being surrendered. This shall occur on or before October 31, 2002.

APPLICABLE STANDARDS AND REGULATIONS:

1. Unless otherwise indicated in this permit, the construction and operation of the subject emission unit(s) shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of Chapter 403, F.S. and Florida Administrative Code Chapters 62-4, 62-103, 62-204, 62-210, 62-212, 62-213, 62-214, 62-296, 62-297; and the applicable requirements of the Code of Federal Regulations Section 40, Parts 60, 72, 73, and 75.

2. Issuance of this permit does not relieve the facility owner or operator from compliance with any applicable federal, state, or local permitting requirements or regulations. [Rule 62-210.300, F.A.C.]

3. These emission units shall comply with all applicable requirements of 40CFR60, Subpart A, General Provisions including:

- 40CFR60.7, Notification and Recordkeeping
- 40CFR60.8, Performance Tests
- 40CFR60.11, Compliance with Standards and Maintenance Requirements
- 40CFR60.12, Circumvention
- 40CFR60.13, Monitoring Requirements
- 40CFR60.19, General Notification and Reporting requirements

4. ARMS Emission Units 001-003, Power Generation, consisting of three 170 megawatt combustion turbines (with optional evaporative inlet cooling) shall comply with all applicable provisions of 40CFR60, Subpart GG, Standards of performance for Stationary Gas Turbines, adopted by reference in Rule 62-204.800(7)(b), F.A.C. The Subpart GG requirement to correct test data to ISO conditions applies. However, such correction is not used for compliance determinations with the BACT standard(s). [Rule 62-204.800(7)(b), F.A.C.]

5. ARMS Emission Units 004-006, Fuel Storage, consisting of three 1 million gallon distillate fuel oil storage tanks shall comply with all applicable provisions of 40CFR60, Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels, adopted by reference in Rule 62-204.800, F.A.C. [Rule 62-204.800(7)(b), F.A.C.]

6. All notifications and reports required by the above specific conditions shall be submitted to RESD.

GENERAL OPERATION REQUIREMENTS

7. <u>Fuels</u>: Only pipeline natural gas or maximum 0.05 percent sulfur fuel oil No. 2 or superior grade of distillate fuel oil shall be fired in this unit. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)] {Note: The limitation of this specific condition is more stringent than the NSPS sulfur dioxide limitation and thus assures compliance with 40 CFR 60.333 and 60.334}

SECTION III. EMISSION UNITS SPECIFIC CONDITIONS

8. Capacity: The maximum heat input rates, based on the lower heating value (LHV) of each fuel to each Unit (1-3) at ambient conditions of 59°F temperature, 60% relative humidity, 100% load, and 14.7 psi pressure shall not exceed 1,623 million Btu per hour (MMBtu/hr) when firing natural gas, nor 1,822 MMBtu/hr when firing No. 2 or superior grade of distillate fuel oil. These maximum heat input rates will vary depending upon ambient conditions and the combustion turbine characteristics. Manufacturer's curves corrected for site conditions or equations for correction to other ambient conditions shall be provided to the Department of Environmental Protection (DEP) within 45 days of completing the initial compliance testing. {Permitting note: The heat input limitations have been placed in the permit to identify the capacity of each emissions unit for purposes of confirming that emissions testing is conducted within 90-100 percent of the emissions unit's rated capacity (or to limit future operation to 110 percent of the test load), to establish appropriate limits and to aid in determining future rule applicability. Regular record keeping is not required for heat input. Instead, the owner or operator is expected to determine heat input whenever emission testing is required, to demonstrate at what percentage of the rated capacity that the unit was tested. Rule 62-297.310(5), F.A.C., included in this permit requires measurement of the process variables for emission tests. Such heat input determination may be based on measurements of fuel consumption by various methods (including but not limited to) fuel flow metering or tank drop measurements, using the heat value of the fuel determined by the fuel vendor or the operator to calculate average hourly heat input during the test.} [Design, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

9. Unconfined Particulate Emissions: During the construction period, unconfined particulate matter emissions shall be minimized by dust suppressing techniques such as covering and/or application of water or chemicals to the affected areas, as necessary. [Rule 62-296.320(4)(c)., F.A.C.]

10. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the owner or operator shall notify the DEP Northeast District office and RESD as soon as possible, but at least within (1) working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; the steps being taken to correct the problem and prevent future recurrence; and where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit and the regulations. [Rule 62-4.130, F.A.C.]

11. Operating Procedures: Operating procedures shall include good operating practices and proper training of all operators and supervisors. The good operating practices shall meet the guidelines and procedures as established by the equipment manufacturers. All operators (including supervisors) of air pollution control devices shall be properly trained in plant specific equipment. [Rule 62-4.070(3), F.A.C.]

12. Circumvention: The owner or operator shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. [Rules 62-210.650, F.A.C.]

13. Maximum allowable hours: Each stationary gas turbine shall only operate up to 4750 hours during any consecutive twelve month period, of which 750 hours of operation per combustion turbine may be while firing oil. Additionally, each turbine shall be limited to 16 hours per day of oil firing. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

14. [DELETED]

15. [DELETED]

Control Technology

16. Dry Low NO_X (DLN) combustors shall be installed on each stationary combustion turbine to control NO_X emissions while firing natural gas. [BACT, Rule 62-4.070, F.A.C.]

17. The permittee shall design each stationary combustion turbine, ducting, and stack(s) so as to not preclude installation of SCR equipment and/or oxidation catalyst in the event of a failure to achieve the NO_X limits given in Specific Condition No. 20 and 21 or the carbon monoxide (CO) limits given in Specific Condition 22. [Rule 62-4.070, F.A.C.]

18. A water injection (WI) system shall be installed for use when firing No. 2 or superior grade distillate fuel oil for control of NO_X emissions. [Design, Rules 62-4.070, 62-212.400, F.A.C.]

19. Consistent with best operation and maintenance practices, the DLN systems shall each be tuned upon initial operation to optimize emissions reductions and shall be maintained to minimize NO_X emissions and CO emissions. Operation of the DLN systems in the diffusion-firing mode shall be minimized when firing natural gas. [Rules 62-4.070, 62-210.650 F.A.C.]

EMISSION LIMITS AND STANDARDS

20. The following table is a summary of the BACT determination and is followed by the applicable specific conditions. Values for NO_X are corrected to 15% O_2 on a dry basis. [Rule 62-212.400, F.A.C.]

Operational Mode (Fuel)	NO_X (15%O2)	CO	VOC***	PM/Visibility (% Opacity)	SO_2/SAM	*Technology and Comments*
Natural Gas	10.5 ppm	15** ppm	2 ppm	10	2 grain S per 100 CF	Dry Low NOx Burners. Clean fuels, good combustion
Fuel Oil	42 ppm*	20 ppm	3.5 ppm	10	0.05% sulfur oil	Water Injection. Units limited to 750 hrs equivalent full load oil operation (per CT) annually. Clean fuels, good combustion

NOTES: * See Condition 21. ** See Condition 22. *** The VOC limit imposed herein was not determined by BACT.

SECTION III. EMISSION UNITS SPECIFIC CONDITIONS

21. Nitrogen Oxides (NO_X) Emissions:

- When NO_X monitoring data is not available, substitution for missing data shall be handled as required by Title IV (40 CFR 75) to calculate any specified average time.
- While firing Natural Gas: The emission rate of NO_X in the exhaust gas shall not exceed 69.3 lb/hr (at ISO conditions) on a 24 hr block average as measured by the continuous emission monitoring system (CEMS). In addition, NO_X emissions calculated as NO_2 (at ISO conditions) shall not exceed 10.5 ppm @15% O_2 to be demonstrated by annual stack test nor 9 ppm @15% O_2 to be demonstrated by the initial "new and clean" GE performance stack test. Note: Basis for lb/hr limit is 10.5 ppm @ 15% O_2, full load. [Rule 62-212.400, F.A.C.]
- While firing Fuel oil: The concentration of NO_X in the exhaust gas shall not exceed 42 ppmvd at 15% O_2 on the basis of a 3 hr average as measured by the continuous emission monitoring system (CEMS). In addition, NO_X emissions calculated as NO_2 (at ISO conditions) shall not exceed 42 ppm @15% O_2 to be demonstrated by stack test. [Rule 62-212.400, F.A.C.]
- After combusting fuel oil for at least 400 hours on any individual CT, the permittee shall prepare and submit for the Department's review and acceptance an engineering report regarding the lowest NO_X emission rate that can consistently be achieved when firing distillate oil. This lowest recommended rate shall include a reasonable operating margin, taking into account long-term performance expectations and good operating and maintenance practices. The Department may revise the NO_X emission rate based upon this report. [BACT determination]

22. Carbon Monoxide (CO) emissions: The concentration of CO in the exhaust gas when firing natural gas shall not exceed 15 ppmvd when firing natural gas and 20 ppmvd when firing fuel oil as measured by EPA Method 10. CO emissions (at ISO conditions) shall not exceed 48.0 lb/hr (when firing natural gas) and 65.0 lb/hr (when firing fuel oil) as indicated by EPA Method 10. [Rule 62-212.400, F.A.C.]

- Within 18 months after the initial compliance test on any individual CT, the permittee shall prepare and submit for the Department's review and acceptance an engineering report regarding the lowest CO emission rate that can consistently be achieved firing natural gas. This lowest recommended rate shall include a reasonable operating margin, taking into account long-term performance expectations and good operating and maintenance practices. The Department may revise the CO emission rate based upon this report. [BACT determination]

23. Sulfur Dioxide (SO_2) emissions: SO_2 emissions (at ISO conditions) shall not exceed 1.1 pounds per hour when firing pipeline natural gas and 98.2 pounds per hour when firing maximum 0.05 percent sulfur No. 2 or superior grade distillate fuel oil as measured by applicable compliance methods described below. [Rule 62-212.400, F.A.C.]

24. Visible emissions (VE): VE emissions shall not exceed 10 percent opacity when firing natural gas or No. 2 or superior grade of fuel oil. Particulate matter emissions shall not exceed 9.0

lb/hr (front catch) while firing natural gas and 17.0 lb/hr (front catch) while firing fuel oil as indicated by opacity. [Rule 62-296.320(4)(b), F.A.C.]

25. Volatile Organic Compounds (VOC) Emissions: The concentration of VOC in the exhaust gas when firing natural gas shall not exceed 2 ppmvd when firing natural gas and 3.5 ppmvd when firing fuel oil as assured by EPA Methods 18 and/or 25 A. VOC emissions (at ISO conditions) shall not exceed 4.0 lb/hr (when firing natural gas) and 7.5 lb/hr (when firing fuel oil) as indicated by EPA Methods 18 and/or 25A. [Rule 62-212.400, F.A.C.]

EXCESS EMISSIONS

26. Excess emissions resulting from startup, shutdown or malfunction shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized. Excess emissions occurrences shall in no case exceed two hours in any 24-hour period for other reasons unless specifically authorized by DEP for longer duration. Operation below 50% output shall be limited to 2 hours per unit cycle (breaker closed to breaker open). Excess emissions caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction, shall be prohibited pursuant to Rule 62-210.700, F.A.C.

27. Excess Emissions Report: If excess emissions occur due to malfunction, the owner or operator shall notify RESD within (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident. Pursuant to the New Source Performance Standards, excess emissions shall also be reported in accordance with 40 CFR 60.7, Subpart A. [Rules 62-4.130 and 62-210.700(6), F.A.C.]

COMPLIANCE DETERMINATION

28. Compliance with the allowable emission limiting standards shall be determined within 60 days after achieving the maximum production rate, for each fuel, at which this unit will be operated, but not later than 180 days of initial operation of the unit for that fuel, and annually thereafter as indicated in this permit, by using the following reference methods as described in 40 CFR 60, Appendix A (1997 version), and adopted by reference in Chapter 62-204.800, F.A.C.

29. Initial (I) performance tests shall be performed on each unit while firing natural gas as well as while firing fuel oil, in accordance with Specific Condition 28. Initial tests shall also be conducted after any modifications (and shake down period not to exceed 100 days after starting the CT) to air pollution control equipment, including low NO_X burners or SCR. Annual (A) compliance tests shall be performed during every federal fiscal year (October 1 - September 30) pursuant to Rule 62-297.310(7), F.A.C., on each unit as indicated. The following reference methods shall be used. No other test methods may be used for compliance testing unless prior DEP approval is received in writing.

- EPA Reference Method 9, "Visual Determination of the Opacity of Emissions from Stationary Sources" (I, A).
- EPA Reference Method 10, "Determination of Carbon Monoxide Emissions from Stationary Sources" (I, A).
- EPA Reference Method 20, "Determination of Oxides of Nitrogen Oxide, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines." Initial test only for compliance with 40CFR60 Subpart GG and (I, A) short-term NO_X BACT limits (EPA reference Method 7E, "Determination of Nitrogen Oxides Emissions from Stationary Sources" or RATA test data may be used to demonstrate compliance for annual test requirement).
- EPA Reference Method 18, and/or 25A, "Determination of Volatile Organic Concentrations." Initial test only.

30. <u>Continuous compliance with the NO_X emission limits</u>: Continuous compliance with the NO_X emission limits shall be demonstrated with the CEM system based on the applicable averaging time of 24-hr block average (DLN technology while burning gas) or a 3-hr average (SCR technology or while burning oil). For the 24-hr block average (lb/hr) emissions may be determined via EPA Method 19 or equivalent EPA approved methods. Based on CEMS data. a separate compliance determination is conducted at the end of each operating day (or 3-hr period when applicable) and a new average emission rate is calculated from the arithmetic average of all valid hourly emission rates from the previous operating day (or 3-hr period when applicable). Valid hourly emission rates shall not include periods of startup, shutdown, or malfunction as defined in Rule 62-210.200 F.A.C., where emissions exceed the applicable NO_X standard. These excess emissions periods shall be reported as required in Conditions 26 and 27. A valid hourly emission rate shall be calculated for each hour in which at least two NO_X concentrations are obtained at least 15 minutes apart. [Rules 62-4.070 F.A.C., 62-210.700, F.A.C., and 40 CFR 75]

31. <u>Compliance with the SO_2 and PM/PM_{10} emission limits</u>: Notwithstanding the requirements of Rule 62-297.310(7), F.A.C., the use of pipeline natural gas and maximum 0.05 percent sulfur (by weight) No. 2 or superior grade distillate fuel oil, is the method for determining compliance for SO_2 and PM_{10}. For the purposes of demonstrating compliance with the 40 CFR 60.333 SO_2 standard and the 0.05% S limit, fuel oil analysis using ASTM D2880-941 or D4294-90 (or equivalent latest version) for the sulfur content of liquid fuels and D1072-80, D3031-81, D4084-82 or D3246-81 (or equivalent latest version) for sulfur content of gaseous fuel shall be utilized in accordance with the EPA-approved custom fuel monitoring schedule or natural gas supplier data may be submitted or the natural gas sulfur content referenced in 40 CFR 75 Appendix D may be utilized. The applicant is responsible for ensuring that the procedures above are used for determination of fuel sulfur content. Analysis may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency pursuant to 40 CFR 60.335(e) (1997 version).

32. Compliance with CO emission limit: An initial test for CO shall be conducted concurrently with the initial NO_X test, as required. The initial NO_X and CO test results shall be the average of three valid one-hour runs. Annual compliance testing for CO may be conducted concurrent with the annual RATA testing for NO_X required pursuant to 40 CFR 75 (required for gas only).

33. Compliance with the VOC emission limit: An initial test is required to demonstrate compliance with the VOC emission limit. Thereafter, CO emission limit will be employed as surrogate and no annual testing is required.

34. Testing procedures: Testing of emissions shall be conducted with the combustion turbine operating at permitted capacity. Permitted capacity is defined as 90-100 percent of the maximum heat input rate allowed by the permit, corrected for the average ambient air temperature during the test (with 100 percent represented by a curve depicting heat input vs. ambient temperature). If it is impracticable to test at permitted capacity, the source may be tested at less than permitted capacity. In this case, subsequent operation is limited by adjusting the entire heat input vs. ambient temperature curve downward by an increment equal to the difference between the maximum permitted heat input (corrected for ambient temperature) and 110 percent of the value reached during the test until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purposes of additional compliance testing to regain the permitted capacity. Test procedures shall meet all applicable requirements (i.e., testing time frequency, minimum compliance duration, etc.) of Chapter 62-204.800 F.A.C.

35. Test Notification: The DEP's Northeast District office and RESD shall be notified, in writing, at least 30 days prior to the initial performance tests and RESD notified at least 15 days before annual compliance test(s). [40 CFR 60.11]

36. Special Compliance Tests: The DEP or RESD may request a special compliance test pursuant to Rule 62-297.310(7), F.A.C., when, after investigation (such as complaints, increased visible emissions, or questionable maintenance of control equipment), there is reason to believe that any applicable emission standard is being violated.

37. Test Results: Compliance test results shall be submitted to RESD no later than 45 days after completion of the last test run. [Rule 62-297.310(8), F.A.C.]

NOTIFICATION, REPORTING, AND RECORDKEEPING

38. Records: All measurements, records, and other data required to be maintained by JEA shall be recorded in a permanent form and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. These records shall be made available to DEP and RESD representatives upon request.

39. Emission Compliance Stack Test Reports: A test report indicating the results of the required compliance tests shall be filed as per Condition 37. above. The test report shall provide sufficient detail on the tested emission unit and the procedures used to allow the Department to

determine if the test was properly conducted and if the test results were properly computed. At a minimum, the test report shall provide the applicable information listed in Rule 62-297.310(8), F.A.C.

40. Special Record Keeping Requirements: The owner or operator shall obtain, make, and keep the following records related to fuel usage:

    (1) Hours of operation for each combustion turbine by fuel type shall be submitted with the Annual Operation Report (AOR) for the prior year.

    (2) Hours of operation for each combustion turbine shall kept for each consecutive 12-month period by fuel type.

    (3) Daily hours of fuel oil operation shall be kept for each combustion turbine during any day in which fuel oil is fired.

MONITORING REQUIREMENTS

41. Continuous Monitoring System: The permittee shall install, calibrate, maintain, and operate a continuous emission monitor in the stack to measure and record the nitrogen oxides emissions from each (CT) unit. Periods when NO_X emissions are above the standards as listed in Specific Condition No 21, shall be reported to RESD pursuant to Rule 62-4.160(8), F.A.C. Following the format of 40 CFR 60.7, periods of startup, shutdown and malfunction shall be monitored, recorded, and reported as excess emissions when emission levels exceed the standards listed in Specific Condition No. 21 except as noted in Specific Condition No. 30. [Rule 62-204.800 and 40 CFR 60.7 (1997 version)]

42. CEMS in lieu of Water to Fuel Ratio: The NO_X CEMS shall be used in lieu of the water/fuel monitoring system for reporting excess emissions in accordance with 40 CFR 60.334(c)(1), Subpart GG (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.

43. Continuous Monitoring System Reports: The monitoring devices shall comply with the certification and quality assurance, and any other applicable requirements of Rule 62-297.520, F.A.C., 40 CFR 60.13, including certification of each device in accordance with 40 CFR 60, Appendix B, Performance Specifications and 40 CFR 60.7(a)(5) or 40 CFR Part 75. Quality assurance procedures must conform to all applicable sections of 40 CFR 60, Appendix F or 40CFR75. Data on CEM equipment specifications, manufacturer, type, calibration and maintenance needs, and its proposed location shall be provided to the Department's Northeast District Office as well as RESD no later than 45 days prior to the first scheduled certification test pursuant to 40 CFR 75.62.

SECTION III. EMISSION UNITS SPECIFIC CONDITIONS

44. Fuel Oil Monitoring Schedule: The following monitoring schedule for No. 2 or superior grade fuel oil shall be followed: For all bulk shipments of No. 2 or superior grade fuel oil received at the Brandy Branch Power Plant, an analysis which reports the sulfur content and nitrogen content of the fuel shall be provided by the fuel vendor. The analysis shall also specify the methods by which the analyses were conducted and shall comply with the requirements of 40 CFR 60.335(d).

45. Natural Gas Monitoring Schedule: The following custom monitoring schedule for natural gas is approved (pending EPA concurrence) in lieu of the daily sampling requirements of 40 CFR 60.334 (b)(2):

- The permittee shall apply for an Acid Rain permit in compliance with the deadlines specified in 40 CFR 72.30.
- The permittee shall submit a monitoring plan, certified by signature of the Designated Representative that commits to using a primary fuel of pipeline supplied natural gas (sulfur content less than 20 gr/100 scf pursuant of 40 CFR 75.11(d)(2)).
- Each unit shall be monitored for SO_2 emissions using methods consistent with the requirements of 40 CFR 75 and certified by the USEPA.
- JEA shall notify DEP of any change in natural gas supply for reexamination of this monitoring schedule. A substantial change in natural gas quality (i.e., sulfur content variation of greater than 1 grain per 100 cubic foot of natural gas) shall be considered as a change in the natural gas supply. Sulfur content of the natural gas will be monitored weekly by the natural gas supplier during the interim period when this monitoring schedule is being reexamined.

46. Determination of Process Variables:

- The permittee shall operate and maintain equipment and/or instruments necessary to determine process variables, such as process weight input or heat input, when such data is needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.
- Equipment and/or instruments used to directly or indirectly determine such process variables, including devices such as belt scales, weigh hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value [Rule 62-297.310(5), F.A.C]

APPENDIX BD
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

JEA Brandy Branch Facility
PSD-FL-267 and 0310485-001-AC
Duval County, Florida

BACKGROUND

The applicant, JEA (formerly Jacksonville Electric Authority) proposes to install three nominal 170 megawatt (MW) General Electric PG 7241 FA combustion turbine-electrical generators at the planned Brandy Branch Facility near Baldwin City, Duval County. The proposed project will result in "significant increases" with respect to Table 62-212.400-2, Florida Administrative Code (F.A.C.) of emissions of particulate matter (PM and PM_{10}), carbon monoxide (CO), nitrogen oxides (NO_X), sulfur dioxide (SO_2), and sulfuric acid mist (SAM). The project is therefore subject to review for the Prevention of Significant Deterioration (PSD) and a determination of Best Available Control Technology (BACT) in accordance with Rules 62-212.400, F.A.C.

The new units will operate in simple cycle mode and intermittent duty and exhaust through separate 90-foot stacks. JEA proposes to operate these units up to 4000 hours on natural gas and 800 hours on maximum 0.05 percent sulfur distillate fuel oil. Descriptions of the process, project. air quality effects, and rule applicability are given in the Technical Evaluation and Preliminary Determination dated August 11, 1999, accompanying the Department's Intent to Issue.

DATE OF RECEIPT OF A BACT APPLICATION:

The application was received on May 18, 1999 and included a proposed BACT proposal prepared by the applicant's consultant. Black & Veatch.

REVIEW GROUP MEMBERS:

Michael P. Halpin. P.E. and A. A. Linero, P.E.

BACT DETERMINATION REQUESTED BY THE APPLICANT:

POLLUTANT	CONTROL TECHNOLOGY	PROPOSED BACT LIMIT
Nitrogen Oxides	Dry Low NO_X Combustors Water Injection (Oil)	12 ppmvd @ 15% O_2 (gas) 42 ppmvd @ 15% O_2 (oil)
Particulate Matter	Pipeline Natural Gas No. 2 Distillate Oil (800 hr/yr) Combustion Controls	10% Opacity
Carbon Monoxide	As Above	15 ppm (gas, baseload) 20 ppm (oil baseload)
Sulfur Dioxide	As Above	0.05% S in fuel oil
Sulfuric Acid Mist	As Above	0.05% S in fuel oil

According to the application, the maximum emissions from the facility will be approximately 858 tons per year (TPY) of NO_X, 366 TPY of CO, 75 TPY of PM/PM_{10}, 124 TPY of SO_2, 15 TPY of SAM, and 21 TPY of VOC.

BACT DETERMINATION PROCEDURE:

In accordance with Chapter 62-212.400, F.A.C., this BACT determination is based on the maximum degree of reduction of each pollutant emitted which the Department of Environmental Protection (Department), on a case by case basis, taking into account energy, environmental and economic impacts, and other costs, determines is achievable through application of production processes and available methods, systems, and techniques. In addition, the regulations state that, in making the BACT determination, the Department shall give consideration to:

- Any Environmental Protection Agency determination of BACT pursuant to Section 169, and any emission limitation contained in 40 CFR Part 60 - Standards of Performance for New Stationary Sources or 40 CFR Part 61 - National Emission Standards for Hazardous Air Pollutants.
- All scientific, engineering, and technical material and other information available to the Department.
- The emission limiting standards or BACT determination of any other state.
- The social and economic impact of the application of such technology.

The EPA currently stresses that BACT should be determined using the "top-down" approach. The first step in this approach is to determine, for the emission unit in question, the most stringent control available for a similar or identical emission unit or emission unit category. If it is shown that this level of control is technically or economically unfeasible for the emission unit in question, then the next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical, environmental, or economic objections.

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES:

The minimum basis for a BACT determination is 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines (NSPS). The Department adopted subpart GG by reference in Rule 62-204.800, F.A.C. The key emission limits required by Subpart GG are 75 ppmvd NO_X @ 15% O_2 (assuming 25 percent efficiency) and 150 ppmvd SO_2 @ 15% O_2 (or <0.8% sulfur in fuel). The BACT proposed by JEA is within the NSPS limit, which allows NO_X emissions, over 110 ppmvd for the high efficiency units to be purchased for the Brandy Branch Facility.

No National Emission Standard for Hazardous Air Pollutants exists for stationary gas turbines.

DETERMINATIONS BY EPA AND STATES:

The following table is based primarily on "F" Class intermittent-duty simple cycle turbines recently permitted or still under review. One project (PREPA) based on smaller units but permitted to operate continuously is included as an example of a simple cycle unit with add-on control equipment. Another continuous-duty project (Lakeland) based on the larger "G" Class is also included. The proposed JEA Brandy Branch project is included to facilitate comparison.

APPENDIX BD
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

Project Location	Power Output and Duty	NO_X Limit ppmvd @ 15% O_2 and Fuel	Technology	Comments
Lakeland, FL	250 MW SC CON	9/9 – NG (by 2002) 42/15 - No. 2 FO	DLN/HSCR WI/HSCR	250 MW WH 501G CT Initially 25 ppm NO_X limit on gas Issued 7/98. 250 hrs on oil.
Oleander Cocoa, FL	850 MW SC INT	9 - NG 42 - No. 2 FO	DLN WI	5x170 MW GE PG7241FA CTs Draft 4/99. 1000 hrs on oil
JEA Brandy, FL	510 MW SC INT	12 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE MS7241FA CTs Application 5/99. 800 hrs on oil
JEA Kennedy, FL	170 MW SC INT	15 - NG 42 - No. 2 FO	DLN WI	170 MW GE MS7241FA CT Issued 2/99. Not PSD/BACT
TEC Polk Power, FL	330 MW SC INT	10.5 – NG 42 – No. 2 F.O.	DLN WI	2x165 MW GE MS7241FA CTs Application 2/99. 876 hrs on oil
Dynegy Heard, GA	510 MW SC INT	15 – NG	DLN	3x170 MW WH 501F CTs Application. Gas only
Tenaska Heard, GA	960 MW SC INT	15 - NG 42 - No. 2 FO	DLN WI	6x170 MW GE PG7241FA CTs Issued 12/98. 720 hrs on oil
Thomaston, GA	680 MW SC INT	15 - NG 42 - No. 2 FO	DLN WI	4x170 MW GE PG7241FA CTs Application. 1687 hrs on oil
Dynegy Reidsville, NC	900 MW SC INT	15 – NG (by 2002) 42 – No. 2 FO	DLN WI	5x180 MW WH 501F CTs Initially 25 ppm NO_X limit on gas Draft 5/98. 1000 hrs on oil.
RockGen Cristiana, WI	525 MW SC INT	15/12 – NG 42 - No. 2 FO	DLN WI	3x175 MW GE PG7241FA CTs 15/12 ppm are on 1/24 hr basis Issued 1/99. 800 hrs on oil
SEI Neenah, WI	330 MW SC INT	15/12 - NG 42 - No. 2 FO	DLN WI	2x165 MW GE PG7241FA CTs 15/12 ppm are on 1/24 hr basis Issued 1/99. 8760/699 hrs gas/oil
PREPA, PR	248 MW SC CON	10 - No. 2 FO	WI & HSCR	3x83 MW ABB GT11N CTs Issued 12/95.

CON = Continuous | DLN = Dry Low NO_X Combustion | FO = Fuel Oil | GE = General Electric
SC = Simple Cycle | SCR = Selective Catalytic Reduction | NG = Natural Gas | WH = Westinghouse
INT = Intermittent | HSCR = Hot SCR | WI = Water or Steam Injection | ABB = Asea Brown Bovari

Project Location	CO - ppm (or as indicated)	VOC - ppm (or as indicated)	PM - lb/hr (or as indicated)	Technology and Comments
Lakeland, FL	25 - NG or 10 by Ox Cat 75 - FO @ 15% O_2	4 – NG 10 – FO	10% Opacity	Clean Fuels Good Combustion
Oleander Cocoa, FL	12 - NG 20 - FO	3 – NG 6 – FO	10% Opacity	Clean Fuels Good Combustion
JEA Brandy, FL	15 - NG 20/26 (full/part load) - FO	1.4 – NG 1.4 – FO	9 lb/hr - NG 17 lb/hr - FO	Clean Fuels Good Combustion
JEA Kennedy, FL	15 - NG 20 - FO	1.4 – NG 3.5 – FO	9 lb/hr - NG 17 lb/hr - FO	Clean Fuels Good Combustion
TEC Polk Power, FL	15 - NG 33 - FO	7 – NG 7 – FO	10% Opacity	Clean Fuels Good Combustion
Dynegy Heard Co., GA	25 - NG	? – NG	? - NG	Clean Fuels Good Combustion
Tenaska Heard Co., GA	15 - NG 20 - FO	? – NG ? – FO	? - NG ? lb/hr - FO	Clean Fuels Good Combustion
Dynegy Reidsville, NC	25 - NG 50 - FO	6 lb/hr – NG 8 lb/hr – FO	6 lb/hr - NG 23 lb/hr - FO	Clean Fuels Good Combustion
RockGen Cristiana, WI	12@>50% load – NG 15@>75% 24@<75% - FO	2 - NG 5 - FO	18 lb/hr – NG 44 lb/hr - FO	Clean Fuels Good Combustion
SEI Neenah, WI	12@>50% load – NG 15@>75% 24@<75% - FO	2 - NG 5 - FO	18 lb/hr - NG 41 lb/hr - FO	Clean Fuels Good Combustion
PREPA, PR	9 – FO @15% O_2	11 – FO @15% O_2	0.0171 gr/dscf	Clean Fuels Good Combustion

OTHER INFORMATION AVAILABLE TO THE DEPARTMENT:

Besides the information submitted by the applicant and that mentioned above, other information available to the Department consists of:

- Comments from EPA dated September 10, 1999
- Comments from the Fish and Wildlife Service dated July 20, August 12 and August 30, 1999
- DOE website information on Advanced Turbine Systems Project
- Alternative Control Techniques Document - NO_X Emissions from Stationary Gas Turbines
- General Electric 39th Turbine State-of-the-Art Technology Seminar Proceedings
- GE Guarantee for Jacksonville Electric Authority Brandy Branch Station Project
- GE Power Generation - Speedtronic™ Mark V Gas Turbine Control System
- GE Combustion Turbine Startup Curves
- JEA Website – www.jea.com
- Goal Line Environmental Technologies Website – www.glct.com
- Catalytica Website – www.catalytica-inc.com

REVIEW OF NITROGEN OXIDES CONTROL TECHNOLOGIES:

Some of the discussion in this section is based on a 1993 EPA document on Alternative Control Techniques for NO_X Emissions from Stationary Gas Turbines. Project-specific information is included where applicable.

Nitrogen Oxides Formation

Nitrogen oxides form in the gas turbine combustion process as a result of the dissociation of molecular nitrogen and oxygen to their atomic forms and subsequent recombination into seven different oxides of nitrogen. Thermal NO_X forms in the high temperature area of the gas turbine combustor. Thermal NO_X increases exponentially with increases in flame temperature and linearly with increases in residence time. Flame temperature is dependent upon the ratio of fuel burned in a flame to the amount of fuel that consumes all of the available oxygen.

By maintaining a low fuel ratio (lean combustion), the flame temperature will be lower, thus reducing the potential for NO_X formation. Prompt NO_X is formed in the proximity of the flame front as intermediate combustion products. The contribution of Prompt to overall NO_X is relatively small in near-stoichiometric combustors and increases for leaner fuel mixtures. This provides a practical limit for NO_X control by lean combustion.

Fuel NO_X is formed when fuels containing bound nitrogen are burned. This phenomenon is not important when combusting natural gas. It is not a significant issue for the JEA project because these units will not be continuously operated, but rather will be "peakers". Also, low sulfur fuel oil (which has more fuel-bound nitrogen than natural gas) is proposed to be used for no more than 800 hours per year (per CT). Uncontrolled emissions range from about 100 to over 600 parts per million by volume, dry, corrected to 15 percent oxygen (ppmvd @15% O_2). The Department estimates uncontrolled emissions at approximately 200 ppmvd @15% O_2 for each turbine of the JEA Project. The proposed NO_X controls will reduce these emissions significantly.

NO_X Control Techniques

Wet Injection

Injection of either water or steam directly into the combustor lowers the flame temperature and thereby reduces thermal NO_X formation. Typical emissions achieved by wet injection are in the range of 15–25 ppmvd when firing gas and 42 ppmvd when firing fuel oil in large combustion turbines. These values often form the basis, particularly in combined cycle turbines, for further reduction to BACT limits by other techniques. Carbon monoxide (CO) and hydrocarbon (HC) emissions are relatively low for most gas turbines. However steam and (more so) water injection increase emissions of both of these pollutants.

Combustion Controls

The excess air in lean combustion cools the flame and reduces the rate of thermal NO_X formation. Lean premixing of fuel and air prior to combustion can further reduce NO_X emissions. This is accomplished by minimizing localized fuel-rich pockets (and high temperatures) that can occur when trying to achieve lean mixing within the combustion zones.

The above principle is depicted in Figure 1 for a General Electric DLN-1 can-annular combustor operating on gas. For ignition, warm-up, and acceleration to approximately 20 percent load, the first stage serves as the complete combustor. Flame is present only in the first stage, which is operated as lean stable combustion will permit. With increasing load, fuel is introduced into the secondary stage, and combustion takes place in both stages. When the load reaches approximately 40 percent, fuel is cut off to the first stage and the flame in this stage is extinguished. The venturi ensures the flame in the second stage cannot propagate upstream to the first stage. When the fuel in the first-stage flame is extinguished (as verified by internal flame detectors), fuel is again introduced into the first stage, which becomes a premixing zone to deliver a lean, unburned, uniform mixture to the second stage. The second stage acts as the complete combustor in this configuration.

To further reduce NO_X emissions, GE developed the DLN-2.0 (cross section shown in Figure 1) wherein air usage (other than for premixing) was minimized. The venturi and the centerbody assembly were eliminated and each combustor has a single burning zone. So-called "quaternary fuel" is introduced through pegs located on the circumference of the outward combustion casing.

GE has made further improvements in the DLN design. The most recent version is the DLN-2.6 (proposed for the JEA project). The combustor is similar to the DLN-2 with the addition of a sixth (center) fuel nozzle. The emission characteristics of the DLN-2.6 combustor while firing natural gas are given in Figure 2 for a unit tuned to meet a 15 ppmvd NO_X limit (by volume, dry corrected to at 15 percent oxygen) at Jacksonville Electric Authority's Kennedy Station.

NO_X concentrations are higher in the exhaust at lower loads because the combustor does not operate in the lean pre-mix mode. Therefore such a combustor emits NO_X at concentrations of 15 ppmvd at loads between 50 and 100 percent of capacity, but concentrations as high as 100 ppmvd at less than 50 percent of capacity. Note that VOC comprises a very small amount of the "unburned hydrocarbons" which in turn is mostly non-VOC methane.

The combustor can be tuned differently to achieve emissions as low as 9 ppm of NO_X and 9 ppm of CO. Emissions characteristics while firing oil are expected to be similar for the DLN-2.6 as they are for those of the DLN-2.0 shown in Figure 3. Simplified cross sectional views of the totally premixed DLN-2.6 combustor to be installed at the JEA project are shown in Figure 4.

In all but the most recent gas turbine combustor designs, the high temperature combustion gases are cooled to an acceptable temperature with dilution air prior to entering the turbine (expansion) section. The sooner this cooling occurs, the lower the thermal NO_X formation. Cooling is also required to protect the first stage nozzle. When this is accomplished by air cooling, the air is injected into the component and is ejected into the combustion gas stream, causing a further drop in combustion gas temperature. This, in turn, lowers achievable thermal efficiency for the unit.

Larger units, such as the Westinghouse 501 G or the planned General Electric 7H. use steam in a closed loop system to provide much of the cooling. The fluid is circulated through the internal portion of the nozzle component or around the transition piece between the combustor and the nozzle and does not enter the exhaust stream. Instead it is normally sent back to a steam generator. The difference between flame temperature and firing temperature into the first stage is minimized and higher efficiency is attained.

Another important result of steam cooling is that a higher firing temperature can be attained with no increase in flame temperature. Flame temperatures and NO_X emissions can therefore be maintained at comparatively low levels even at high firing temperatures. At the same time, thermal efficiency should be greater when employing steam cooling. A similar analysis applies to steam cooling around the transition piece between the combustor and first stage nozzle.

The relationship between flame temperature, firing temperature, unit efficiency, and NO_X formation can be appreciated from Figure 5 which is from a General Electric discussion on these principles. In addition to employing pre-mixing and steam cooling, further reductions are accomplished through design optimization of the burners, testing, further evaluation, etc.

At the present time, emissions achieved by combustion controls are as low as 9 ppmvd from gas turbines smaller than 200 MW (simple cycle), such as GE "F Class" units. Even lower NO_X emissions are achieved from certain units smaller than 100 MW, such as the GE 7EA line.

Selective Catalytic Combustion

Selective catalytic reduction (SCR) is an add-on NO_X control technology that is employed in the exhaust stream following the gas turbine. SCR reduces NO_X emissions by injecting ammonia into the flue gas in the presence of a catalyst. Ammonia reacts with NO_X in the presence of a catalyst and excess oxygen yielding molecular nitrogen and water. The catalysts used in combined cycle, low temperature applications (conventional SCR), are usually vanadium or titanium oxide and account for almost all installations. For high temperature applications (Hot SCR up to 1125 °F), such as simple cycle turbines, zeolite catalysts are available but used in few applications to-date. SCR units are typically used in combination with wet injection or DLN combustion controls.

In the past, sulfur was found to poison the catalyst material. Sulfur-resistant catalyst materials are now becoming more available. Catalyst formulation improvements have proven effective in resisting sulfur-induced performance degradation with fuel oil in Europe and Japan, where conventional SCR catalyst life in excess of 4 to 6 years has been achieved, while 8 to 10 years catalyst life has been reported with natural gas.

Excessive ammonia use tends to increase emissions of CO, ammonia (slip) and particulate matter (when sulfur-bearing fuels are used).

As of early 1992, over 100 gas turbine installations already used SCR in the United States. Per the above table, only one combustion turbine project in Florida (FPC Hines Power Block 1) employs SCR. The equipment was installed on a temporary basis because Westinghouse had not yet demonstrated emissions as low as 12 ppmvd by DLN technology at the time the units were to start up in 1998. SCR is also proposed on a permanent basis for the expansion of the FPC Hines Facility (Power Block II). Seminole Electric will install SCR on a previously-permitted 501F unit at the Hardee Unit 3 project. The reasons are similar to those for the FPC Hines Power Block I.

Permit limits as low as 2.25 to 3.5 ppmvd NO_X have been specified using SCR on combined cycle F Class projects throughout the country.

Selective Non-Catalytic Combustion

Selective non-catalytic reduction (SNCR) reduction works on the same principle as SCR. The differences are that it is applicable to hotter streams than conventional or hot SCR, no catalyst is required, and urea can be used as a source of ammonia. No applications have been identified wherein SNCR was applied to a gas turbine because the exhaust temperature of 1100 °F is too low to support the NO_X removal mechanism.

The Department did, however, specify SNCR as one of the available options for the combined cycle Santa Rosa Energy Center. The project will incorporate a large 600 MMBtu/hr duct burner in the heat recovery steam generator (HRSG) and can provide the acceptable temperatures (between 1400 and 2000 °F) and residence times to support the reactions.

Emerging Technologies: SCONOX™ and XONON™

There are at last two technologies on the horizon that will influence BACT determinations. These, as usual, are prompted by the needs specific to non-attainment areas such as Southern California.

The first technology is called $SCONO_X$™ and is a catalytic technology that achieves NO_X control by oxidizing and then absorbing the pollutant onto a honeycomb structure coated with potassium carbonate. The pollutant is then released as harmless molecular nitrogen during a regeneration cycle that requires a dilute hydrogen reducing gas. The technology has been demonstrated on small units in California and has been purchased for a small source in Massachusetts.[1] California regulators and industry sources have stated that the first 250 MW block to install SCONOx ™ will be at U.S. Generating's La Paloma Plant near Bakersfield.[2] The overall project includes several more 250 MW blocks with SCR for control.[3] USEPA has identified an "achieved in practice" BACT value of 2.0 ppmvd over a three-hour rolling average based upon the recent performance of a Vernon, California natural gas-fired 32 MW combined cycle turbine (without duct burners) equipped with the patented SCONOx™ system

SCONOx™ technology (at 2.0 ppmvd) is considered to represent LAER in non-attainment areas where cost is not a factor in setting an emission limit. It competes with less-expensive SCR in those areas, but has the advantages that it does not cause ammonia emissions in exchange for NO_X reduction. Advantages of the SCONOx ™ process include in addition to the reduction of NO_X, the elimination of ammonia and the control of some CO emissions. SCONOx™ has not been applied on any major sources in ozone attainment areas.

In a letter dated March 23, 1998 to Goal Line Environmental Technologies, the SCONOx™ process was deemed as technically feasible for maintaining NO_X emissions at 2 ppmvd on a combined cycle unit. ABB Environmental was announced on September 10, 1998 as the exclusive licensee for SCONOx™ for United States turbine applications larger than 100 MW. ABB Power Generation has stated that scale up and engineering work will be required before SCONOx™ can be offered with commercial guarantees for large turbines (based upon letter from Kreminski/Broemmelsiek of ABB Power Generation to the Massachusetts Department of Environmental Protection dated November 4, 1998). SCONOx requires a much lower temperature regime that is not available in simple cycle units and is therefore not feasible for this project. Therefore the SCONOx system cannot be considered as achievable or demonstrated in practice for this application.

The second technology is XONON™, which works by partially burning fuel in a low temperature pre-combustor and completing the combustion in a catalytic combustor. The overall result is low temperature partial combustion (and thus lower NO_X combustion) followed by flameless catalytic combustion to further attenuate NO_X formation. The technology has been demonstrated on combustors on the same order of size as $SCONO_X$ ™ has. However GE has teamed with Catalytica to develop a combustor for gas turbines in the 80-90 MW range before continuing with development on a combustor for a larger unit. XONON™ avoids the emissions of ammonia and the need to generate hydrogen. It is also extremely attractive from a mechanical point of view.

Catalytica Combustion Systems, Inc. develops, manufactures and markets the XONON™ Combustion System. In a press release on October 8, 1998 Catalytica announced the first installation of a gas turbine equipped with the XONON™ Combustion System in a municipally owned utility for the production of electricity. The turbine was started up on that day at the Gianera Generating Station of Silicon Valley Power, a municipally owned utility serving the City of Santa Clara, Calif. The XONON™ Combustion System, deployed for the first time in a commercial setting, is designed to enable turbines to produce environmentally sound power without the need for expensive cleanup solutions. Previously, this XONON™ system had successfully completed over 1,200 hours of extensive full-scale tests which documented its ability to limit emissions of nitrogen oxides, a primary air pollutant, to less than 3 parts per million.

Catalytica's XONON™ system is represented as a powerful technology that essentially eliminates the formation of nitrogen oxides air emissions in gas turbines without impacting the turbine's operating performance. In a definitive agreement signed on November 19, 1998, GE Power Systems and Catalytica agreed to cooperate in the design, application, and commercialization of XONON™ systems for both new and installed GE E-class and F-class turbines used in power generation and mechanical drive applications. This appears to be an up-and-coming technology, the development of which will be watched closely by the Department for future applications. It is not yet available for fuel oil and cycling operation.

REVIEW OF SULFUR DIOXIDE (SO_2) AND SULFURIC ACID MIST (SAM)

SO_2 control processes can be classified into five categories: fuel/material sulfur content limitation, absorption by a solution, adsorption on a solid bed, direct conversion to sulfur, or direct conversion to sulfuric acid. A review of the BACT determinations for combustion turbines contained in the BACT Clearinghouse shows that the exclusive use of low sulfur fuels constitutes the top control option for SO_2.

For this project, the applicant has proposed as BACT the use of 0.05% sulfur oil for up to 800 hours per CT as well as pipeline natural gas. The applicant estimated total emissions for the project at 124 TPY of SO_2 and 15 TPY of SAM. The Department expects the emissions to be lower because of the limited oil consumption and the typical natural gas in Florida that contains less than 1 grain of sulfur per 100 standard cubic feet (gr S/100ft^3). This value is well below the "default" maximum value of 20 gr. S/100 ft^3, but high enough to require a BACT determination.

REVIEW OF PARTICULATE MATTER (PM/PM_{10}) CONTROL TECHNOLOGIES:

Particulate matter is generated by various physical and chemical processes during combustion and will be affected by the design and operation of the NO_X controls. The particulate matter emitted from this unit will mainly be less than 10 microns in diameter (PM_{10}).

Natural gas and 0.05 percent sulfur No. 2 (or superior grade) distillate fuel oil will be the only fuels fired and are efficiently combusted in gas turbines. Such fuels are necessary to avoid damaging turbine blades and other components already exposed to very high temperature and pressure. Natural gas is an inherently clean fuel and contains no ash. The fuel oil to be combusted contains a minimal amount of ash and its use is proposed for only 800 hours per year making any conceivable add-on control technique for PM/PM_{10} either unnecessary or impractical.

A technology review indicated that the top control option for PM/PM_{10} is a combination of good combustion practices, fuel quality, and filtration of inlet air. Total annual emissions of PM_{10} for the project are expected to be approximately 75 tons per year.

REVIEW OF CARBON MONOXIDE (CO) CONTROL TECHNOLOGIES

CO is emitted from combustion turbines due to incomplete fuel combustion. Combustion design and catalytic oxidation are the control alternatives that are viable for the project. The most stringent control technology for CO emissions is the use of an oxidation catalyst.

All combustion turbines using catalytic oxidation appear to be combined cycle units. Among the most recently permitted ones are the 500 MW Wyandotte Energy project in Michigan, the El Dorado project in Nevada, Ironwood in Pennsylvania, Millenium in Massachusetts, and Sutter Calpine in California. The permitted CO values of these units are between 3 and 5 ppm. Catalytic oxidation was recently installed at a cogeneration plant at Reedy Creek (Walt Disney World), Florida to avoid PSD review which would have been required due to increased operation at low load. Seminole Electric recently proposed catalytic oxidation in order to meet the permitted CO limit at its planned 244 MW Westinghouse 501FD combined cycle unit in Hardee County, Florida.[4]

Most combustion turbines incorporate good combustion to minimize emissions of CO. So far this appears to be the only technology proposed at simple cycle turbine projects. These installations typically achieve emissions between 10 and 25 ppm at full load while firing gas. The values of 15 and 20 ppm for gas and oil respectively at baseload proposed in JEA's original application are within the range of recent determinations for simple cycle CO BACT determinations. By comparison, values of 12 and 20 ppm for gas and oil respectively (at baseload) were proposed for the Oleander's project using identical equipment. Values given in GE-based applications are representative of operations between 50 and 100 percent of full load.

REVIEW OF VOLATILE ORGANIC COMPOUND (VOC) CONTROL TECHNOLOGIES

Volatile organic compound (VOC) emissions, like CO emissions, are formed due to incomplete combustion of fuel. There are no viable add-on control techniques as the combustion turbine itself is very efficient at destroying VOC. The applicant has proposed good combustion practices to control VOC. The limits proposed by JEA for this project are 1.4 ppm for both gas and oil firing at baseload. According to GE, however, VOC emissions less than 1.4 ppm were achieved during recent tests of the DLN-2.6 technology when firing natural gas.[5] By comparison, limits of 3 and 6 ppm were proposed for gas and oil firing respectively in the Oleander application. The limits proposed by JEA are sufficiently low to exempt the Brandy Branch project from BACT for VOC.

BACKGROUND ON PROPOSED GAS TURBINE

JEA plans the purchase of three 170 MW (nominal) General Electric PG 7241FA simple cycle gas turbines. This is the most recent designation of GE's line of "F" Class units.

The first commercial GE 7F Class unit was installed in a combined cycle project at the Virginia Power Chesterfield Station in 1990.[6] The initial units had a firing temperature of 2300 °F and a combined cycle efficiency exceeding 50 percent. By the mid-90s, the line was improved by higher combustor pressure, a firing temperature of 2400 °F, and a combined cycle efficiency of approximately 56 percent based on a 167 MW combustion turbine. The line was redesignated as the 7FA Class.

The first GE 7F/FA project in Florida was at the FPL Martin Plant in 1993 and entered commercial service in 1994.[7] The units were equipped with DLN-2 combustors with a permitted NO_X limit of 25 ppmvd. These actually achieved emissions of 13-25 ppmvd of NO_X, 0-3 ppm of CO, and 0-0.17 ppm of VOC.[8] The City of Tallahassee recently received approval to install a GE 7FA Class unit at its Purdom Plant.[9] Although permitted emissions are 12 ppmvd of NO_X, the City obtained a performance guarantee from GE of 9 ppmvd.[10] FPL also obtained a guarantee and permit limit of 9 ppmvd NO_X for six GE 7241FA turbines to be installed at the Fort Myers Repowering project.[11] The Santa Rosa Energy Center in Pace, Florida, also received a permit with a 9 ppmvd NO_X limit for a GE 7241 turbine with DLN-2.6 burners.[12]

Most recently, the Department issued draft BACT determinations for the simple cycle Oleander project in Brevard County and the combined cycle projects in Volusia (Duke Energy) and Osceola County (Kissimmee Utilities). These three draft permits also include NO_X limits of 9 ppmvd based on the DLN-2.6 technology installed on F Class units.

General Electric has primarily relied on further advancement and refinement of DLN technology to provide sufficient NO_X control for their combined cycle turbines in Florida. Where required by BACT determinations of certain states, General Electric incorporates SCR in combined cycle projects.[13] In its recent permits, Florida has included separate and lower limits in the event that DLN emissions limits are not attainable or the applicant selects a manufacturer that does not provide combustors capable of meeting 9 ppmvd.

GE's approach of progressively refining such technology is a proven one, even on some relatively large units. Recently GE Frame 7FA units met performance guarantees of 9 ppmvd with "DLN-2.6" burners at Fort St. Vrain, Colorado and Clark County, Washington.[14] Although the permitted limit is 15 ppmvd, GE has already achieved emission levels of approximately 6-7 ppmvd on gas at a dual-fuel 7EA (120 MW combined cycle) KUA Cane Island Unit 2.[15] Unit 2 is equipped with DLN-2 combustors. According to GE, similar performance is expected soon on the 7FA line such as the one that will be installed for the JEA Brandy Branch Project. Performance guarantees less than 9 ppmvd can be expected for DLN-2.6 combustors on units delivered in a couple of years.[16]

The 12 ppmvd NO_X limit on natural gas proposed by JEA is a fairly stringent BACT determination for simple cycle F Class, though it is becoming less so. The company has obtained a guarantee from GE to achieve 9 ppmvd, which is for a performance test on a "new and clean unit." The test must be conducted at a steady-state load of 50 to 100 percent and completed within the first 100 fired hours of operation as specified in the GE protocols.

With the frequent start-ups and shutdowns of the unit, JEA is concerned about the ability to maintain the low (9 ppmvd) NO_X values for long periods of time following the performance tests. Presumably, this concern would be lessened should these units be converted to a more continuous duty (i.e. combined cycle). Although the Department is not fully aware of the details of the GE guarantee for Oleander (proposed 9 ppmvd on a simple cycle unit), the Department is aware from discussions with other applicants that a continuing guarantee is available at a substantial cost.[17]

The GE Speedtronic™ Mark V Gas Control System will be used. This control system is designed to fulfill all gas turbine control requirements. These include control of liquid, gas, or both fuels in accordance with the requirements of the speed, load control under part-load conditions, temperature control under maximum capability conditions, or during start-up conditions. Since emissions are controlled utilizing dry low NO_X techniques, fuel staging and combustion mode are also controlled by the Mark V, which also monitors the process. Sequencing of the auxiliaries to allow fully automated start-up, shutdown and cool-down are also handled by the Mark V.[18]

DEPARTMENT BACT DETERMINATION

Following are the BACT limits determined for the JEA project assuming full load. Values for NO_X are corrected to 15% O_2 on a dry volume basis. The emission limits or their equivalents in terms of pounds per hour and NSPS units, as well as the applicable averaging times, are given in the permit Specific Conditions No. 20 through 25.

POLLUTANT	CONTROL TECHNOLOGY	PROPOSED BACT LIMIT
PM/PM_{10}	Pipeline Natural Gas Good Combustion	10 Percent Opacity 9 lb/hr – Gas 17 lb/hr – Fuel Oil
CO	As Above	12* ppm – Gas 20 ppm – Fuel Oil
SO_2/SAM	As Above	2 grains of sulfur per 100 ft^3 gas 0.05 percent sulfur in fuel oil
NO_X	Dry Low NO_X, WI for F.O., limited oil use	10.5 ppmvd – Gas 42* ppmvd – F.O. for 750 of 4750hours

* See discussion below.

RATIONALE FOR DEPARTMENT'S DETERMINATION

- JEA has agreed to shutdown its Southside facility, also located in Duval County. This will result in a net decrease of regulated pollutants which are emitted.
- General Electric has provided a "clean and new" one-time guarantee of 9 ppmvd NO_X.
- Typical "continuous" permit limits nation-wide for these GE 7FA units while operating on natural gas and in simple cycle mode and intermittent duty are 12-15 ppmvd even though GE provides the same "new and clean" guarantees for them. Limits as high as 25 ppmvd have been recently proposed by some for similar units produced by other manufacturers.
- A level of 9 ppmvd NO_X by DLN has been demonstrated on GE 7FA combustion turbines at Fort St. Vrain, Colorado and Clark County, Washington. However the permitted limits are actually higher at these two facilities providing some level of operating margin.
- A limit of 9 ppmvd was proposed by Oleander for five GE7 FA units and is reflected in the Department's recent Draft BACT Determination for that facility. A BACT level of 9 ppmvd has been proposed by Virginia Power for a GE 7FA unit to avoid non-attainment New Source Review.
- The proposed 9 ppmvd limit at Oleander and Virginia Power while firing natural gas is the lowest known Draft BACT value for an "F" frame combustion turbine operating in simple cycle mode and intermittent duty. The 42 ppmvd limit while firing fuel oil is typical.
- The Department prepared a Draft permit for the TEC Polk Power Station Project adopting TEC's proposed 10.5 ppmvd limit for two GE 7FA units, but limited the hours of operation on fuel to less than the hours allowed at Oleander. The TEC Draft BACT is being issued concurrently with the Draft BACT for the JEA project.
- JEA's proposed 12 ppmvd limit for the Brandy Branch Facility while firing natural gas is relatively low for a GE 7FA Class simple cycle, intermittent duty unit.
- The Department however, proposes a BACT limit of 10.5 ppmvd, which is the same as proposed for the TEC project. The Department also proposes to limit oil firing to the same number of hours as TEC (750) and less than the number of hours at Oleander (1000). Considering the applicant's shutdown of its Southside facility in conjunction with the Department's BACT limits, net annual NO_X emissions (TPY) will be approximately zero.
- The Department will still require JEA to meet to meet the "clean and new" limit of 9 ppmvd during initial testing as well as requiring a continuous 9 ppmvd guarantee (or better) in the event that JEA converts the units to continuous duty (i.e. combined cycle).
- The proposed BACT limit of 10.5 ppmvd is about one-tenth of the applicable NSPS limit per 40 CFR 60, Subpart GG for units as efficient as the 7FA.
- The units will be operated in simple cycle mode. Therefore control options, which are feasible for combined cycle units, are not applicable. This rules out Low Temperature (conventional) SCR, which achieves 4.5 ppmvd NO_X or lower. It also rules out the possibility of SCONOx. XONON is not available for F Class dual fuel projects.
- The simple cycle "F Class" turbines have very high exhaust temperatures of up to 1200 °F. Without additional cooling, this is at the higher limit of the present operational temperature of

Hot SCR zeolite catalyst (around 1125°F). The PREPA simple cycle turbines, which use Hot SCR, have exhaust temperatures ranging from 824 to 1024°F and burn exclusively #2 oil.

- The levelized costs of NO_X removal by Hot SCR for the JEA project were estimated by Black & Veatch at $13,380 per ton assuming 4000 hours of operation on natural gas and a reduction from 12 to 5 ppmvd. The Department estimates that this figure is reduced by including oil operation (up to 750 hours per year) and other criteria, but still exceeds $7,000 per ton.
- TEC estimated the cost of Hot SCR at $9,717 per ton of NO_X removed assuming 4,380 and 876 hours per year of operation on gas and oil respectively.
- The Department previously concluded that Hot SCR is cost-effective for continuous duty simple cycle service (Lakeland). EPA also concluded Hot SCR is cost-effective on continuous duty simple cycle projects (PREPA).
- Although the Department does not have a "bright line" cost-effectiveness figure and does not necessarily adopt the precise cost calculations for the JEA and TEC projects, the values projected by JEA and TEC indicate that Hot SCR is not cost-effective for their respective projects.
- Comments from the National Park Service on the Oleander project suggested that a reduction in the applicant's proposed NO_X emissions on oil from 42 ppmvd to 25 ppmvd is possible based on reported oil-fired units listed in the BACT Clearinghouse. GE has advised that it only offers a 42 ppmvd NO_X guarantee on F Class units when firing oil.
- The Department is aware that ABB offers a DLN technology for fuel oil firing applicable to at least certain smaller combustion turbines (ABB-GTX). It is noted, however that ABB does not offer a guarantee of 9 ppmvd on the same unit when firing natural gas.
- It is possible that the NO_X emissions while firing oil from may be reduced from 42*ppmvd by increasing the water injection rate. In order to address this possibility, a specific condition will be added to conduct appropriate testing and prepare an engineering report. The report will be submitted for the Department's review to ensure that the lowest reliable NO_X emission rates while firing oil have been achieved.
- The Department's overall BACT determination is equivalent to approximately 0.5 lb./MW-hr NO_X emissions for combined gas and oil operation. For reference, the new NSPS promulgated on September 3, 1998 requires that new conventional power plants (based on boilers, etc.) meet a limit of 1.6 lb/MW-hr. FDEP BACT analyses typically target values less than 1.0 lb./MW-hr for simple cycle CT's and less than 0.5 lb./MW-hr for combined cycle units.
- VOC emissions of 1.4 ppm while firing gas or oil proposed by the applicant clearly reflect BACT and, in fact, exempt the project from a BACT determination for VOC. The Department will set VOC limits at 2 ppm (gas) and 3.5 ppm (oil). These values are still sufficient to maintain VOC emissions to less than 40 tons per year.
- The Department will set CO limits achievable by good combustion at full load as 12* ppm (gas) and 20 ppm (oil). These values are equal to the lowest values from permitted or proposed simple cycle units and are equal to those proposed by the Department for Oleander and TEC project. Due to the applicant's (higher) guarantee while firing gas of 15 ppm, the specific permit condition will be worded so as to allow for initial 15 ppm operation with a requirement

to conduct appropriate testing and prepare an engineering report. The report will be submitted for the Department's review to ensure that the lowest reliable CO emission rates while firing gas have been achieved.

- Black & Veatch evaluated the use of an oxidation catalyst for the JEA project with an 88 percent control efficiency and having a three-year catalyst life. The oxidation catalyst control system was estimated to increase the capital cost of the project by $1,905,000 with an annualized cost of $509,000 per year. Levelized costs for CO catalyst control were calculated at $4,700 per ton. This figure does not appear to be cost-effective for removal of CO.
- BACT for PM_{10} was determined to be good combustion practices consisting of: inlet air filtering; use of pipeline natural gas; use of clean, low ash, low sulfur fuels for limited hours, and operation of the unit in accordance with the manufacturer-provided manuals.
- PM_{10} emissions will be very low and difficult to measure. Additionally, the higher emission mode will involve fuel oil firing which will occur only approximately 750 hours per year. It is not practical to require running the turbine on oil, simply to conduct tests. Therefore, the Department will set a Visible Emission standard of 10 percent opacity as BACT for both natural gas and fuel oil firing, consistent with the definition of BACT. Examples of installations with similar VE limits include the City of Lakeland, the City of Tallahassee, Santa Rosa Energy Center, FPL Fort Myers, and the Southern Company Barry projects.

Compliance Procedures

POLLUTANT	COMPLIANCE PROCEDURE
Particulate Matter	Method 9
Carbon Monoxide	Annual Method 10 (can use RATA if at capacity)
NO_X (performance)	Annual Method 20 (can use RATA if at capacity)
NO_X (24-hr block average)	NO_X CEMS, O_2 or CO_2 diluent monitor, and flow device as needed
SO_2 and SAM	Custom Fuel Monitoring Schedule

DETAILS OF THE ANALYSIS MAY BE OBTAINED BY CONTACTING:

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

10/13/99
Date:

Approved By:

CH Fancy

for Howard L. Rhodes, Director
Division of Air Resources Management

10/13/99
Date:

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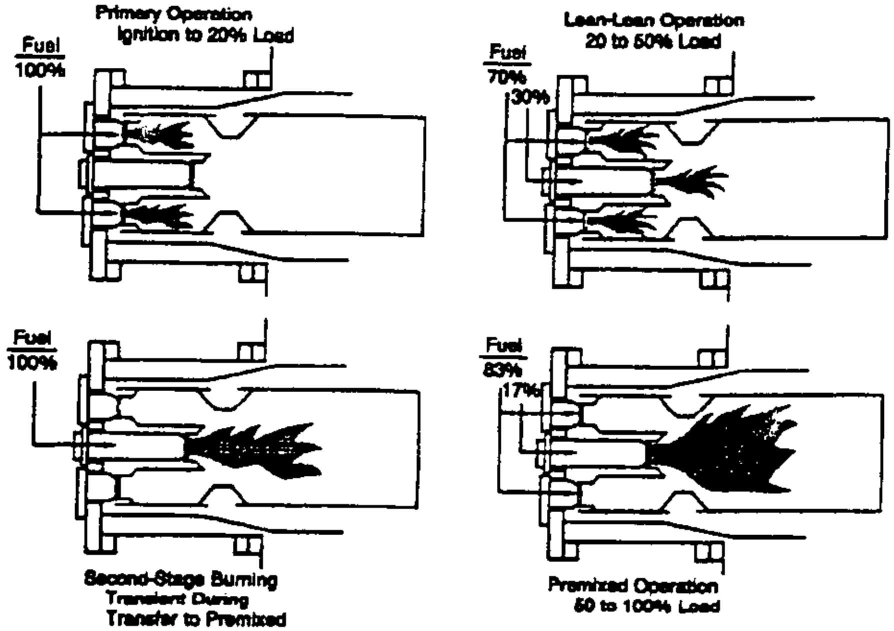

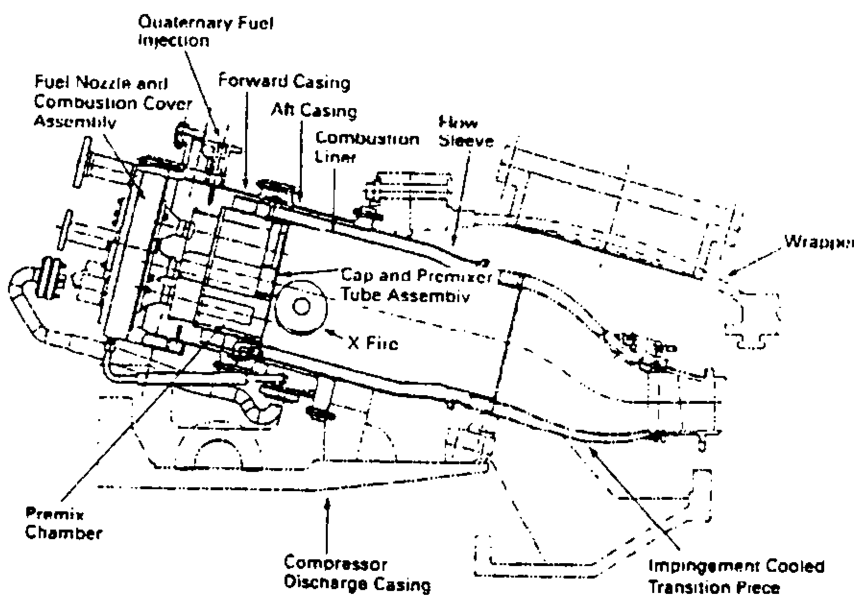

Figure 1 - Dry Low NOx Operating Modes - DLN-1

Cross Section of GE DLN-2

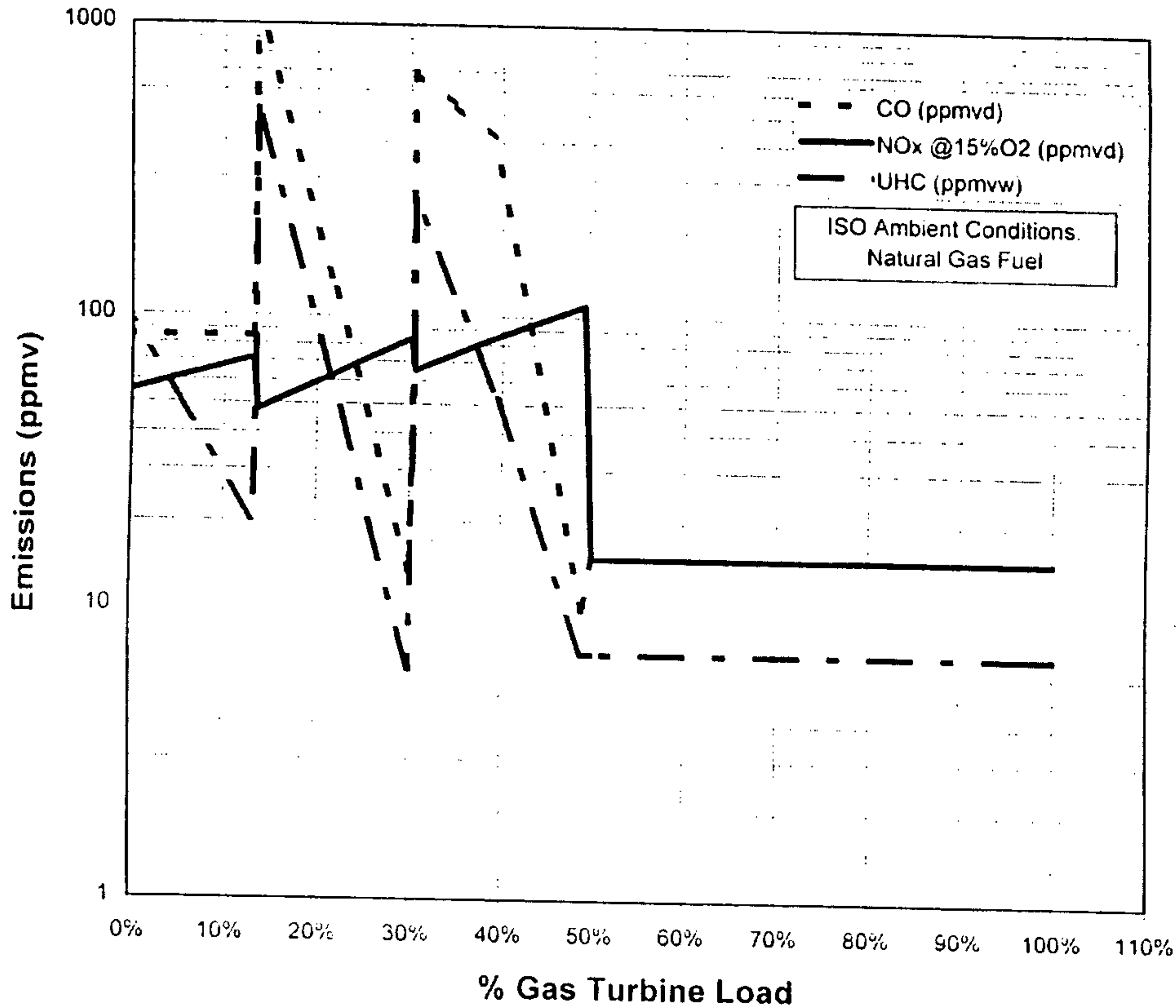

Figure 2 – Emissions Performance Curves for GE DLN-2.6 Combustor Firing Natural Gas in a Dual Fuel GE 7FA Combustion Turbine

(Simple Cycle Intermittent Duty – If Tuned to 15 ppmvd NO_X)

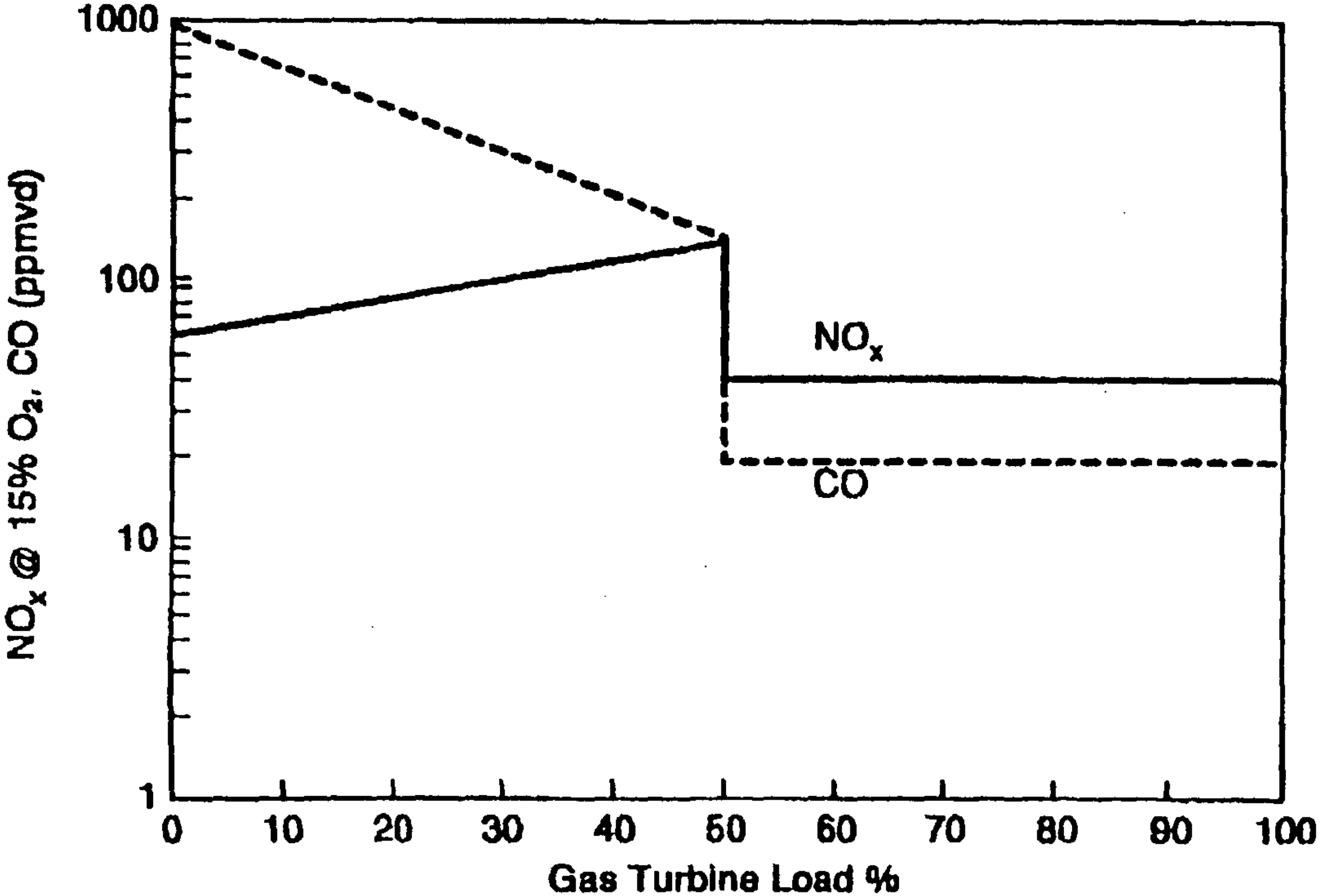

Figure 3 – Emissions Performance for DLN-2 Combustors
Firing Fuel Oil in Dual Fuel GE 7FA Turbine

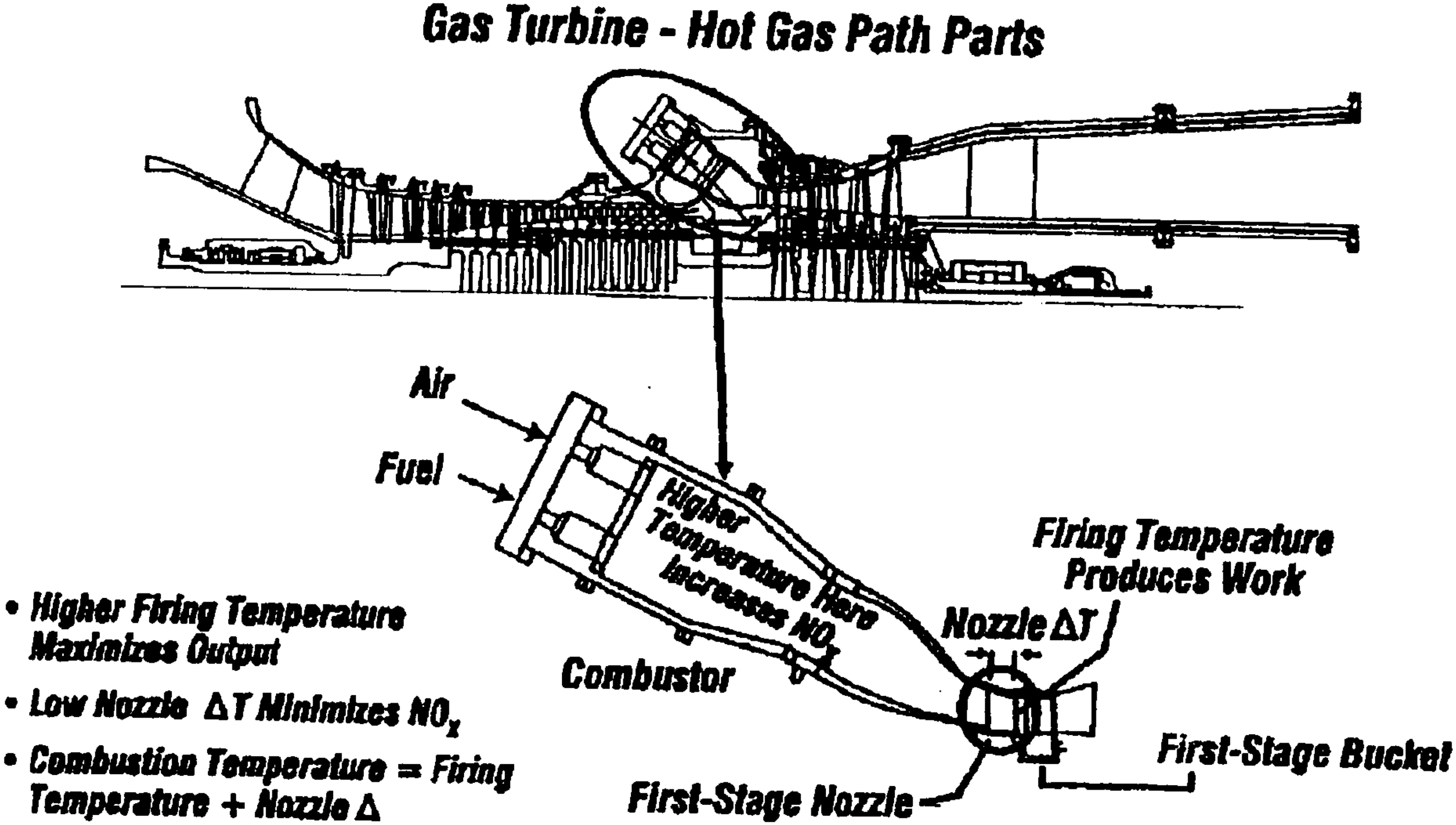

Figure 5 - Relation Between Flame Temperature and Firing Temperature

APPENDIX GC

GENERAL PERMIT CONDITIONS [F.A.C. 62-4.160]

G.1 The terms, conditions, requirements, limitations, and restrictions set forth in this permit are "Permit Conditions" and are binding and enforceable pursuant to Sections 403.161, 403.727, or 403.859 through 403.861, Florida Statutes. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions.

G.2 This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings or exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.

G.3 As provided in Subsections 403.087(6) and 403.722(5), Florida Statutes, the issuance of this permit does not convey any vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state or local laws or regulations. This permit is not a waiver or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in the permit.

G.4 This permit conveys no title to land or water, does not constitute State recognition or acknowledgment of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title.

G.5 This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, or plant life, or property caused by the construction or operation of this permitted source, or from penalties therefore; nor does it allow the permittee to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department.

G.6 The permittee shall properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed or used by the permittee to achieve compliance with the conditions of this permit, as required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by Department rules.

G.7 The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law and at a reasonable time. access to the premises, where the permitted activity is located or conducted to:

a) Have access to and copy and records that must be kept under the conditions of the permit;
b) Inspect the facility, equipment, practices, or operations regulated or required under this permit, and,
c) Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

Reasonable time may depend on the nature of the concern being investigated.

G.8 If, for any reason, the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit, the permittee shall immediately provide the Department with the following information:

a) A description of and cause of non-compliance; and
b) The period of noncompliance, including dates and times; or, if not corrected, the anticipated time the non-compliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the non-compliance.

The permittee shall be responsible for any and all damages which may result and may be subject to enforcement action by the Department for penalties or for revocation of this permit.

G.9 In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the Florida Statutes or Department rules, except where such use is prescribed by Sections 403.73 and 403.111, Florida Statutes. Such evidence shall only be used to the extent it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

G.10 The permittee agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules.

G.11 This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 62-4.120 and 62-730.300, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.

G.12 This permit or a copy thereof shall be kept at the work site of the permitted activity.

G.13 This permit also constitutes:

a) Determination of Best Available Control Technology ( )
b) Determination of Prevention of Significant Deterioration ( ); and
c) Compliance with New Source Performance Standards (X).

G.14 The permittee shall comply with the following:

a) Upon request, the permittee shall furnish all records and plans required under Department rules. During enforcement actions, the retention period for all records will be extended automatically unless otherwise stipulated by the Department.

b) The permittee shall hold at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation) required by the permit, copies of all reports required by this permit, and records of all data used to complete the application or this permit. These materials shall be retained at least three years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule.

c) Records of monitoring information shall include:

1. The date, exact place, and time of sampling or measurements;
2. The person responsible for performing the sampling or measurements;
3. The dates analyses were performed;
4. The person responsible for performing the analyses;
5. The analytical techniques or methods used; and
6. The results of such analyses.

G.15 When requested by the Department, the permittee shall within a reasonable time furnish any information required by law which is needed to determine compliance with the permit. If the permittee becomes aware that relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be corrected promptly.