STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

NOTICE OF FINAL PERMIT

In the Matter of an
Application for Permit by:

Florida Power and Light Company
FPL Martin Power Plant
P.O. Box 176
Indiantown, FL 34956

Authorized Representative:
John M. Lindsay, Plant General Manager

Air Permit No. PSD-FL-327
Project No. 0850001-010-AC
Combined Cycle Unit 8
Martin County, Florida

Enclosed is Final Permit No. PSD-FL-327 that authorizes construction of combined cycle Unit 8 at the existing Martin Power Plant, which is located approximately 7 miles north of Indiantown on State Road 710 in Martin County, Florida. As noted in the Final Determination (attached), the Department made only minor changes to the Final Permit. 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.

Trina L Vielhauer

Trina Vielhauer, 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 4/16/03 to the persons listed:

Mr. John M. Lindsay, FPL*
Mr. K. H. Simmons, FPL
Mr. Willie Welch, FPL
Mr. Ken Kosky, Golder Associates
Mr. Buck Oven, Siting Office
Mr. Tom Tittle, SED
Mr. Gregg Worley, EPA Region 4
Mr. John Bunyak, NPS

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.

Victoria Gibson April 16, 2003
(Clerk) (Date)

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Mr. John M. Lindsay
Plant General Manager
Florida Power & Light Company
Martin Power Plant
Post Office Box 176
Indiantown, FL 34956

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PUBLIC NOTICE

On July 31, 2002, the Department distributed a draft permit package that authorizes the construction of Unit 8 at the existing Martin Power Plant, which is located approximately 7 miles north of Indiantown on State Road 710 in Martin County, Florida. Unit 8 will be a "4-on-1" combined cycle gas turbine system with an electrical generating capacity of approximately 1150 MW. The "Public Notice of Intent to Issue Permit" was published in the Indiantown News on September 12, 2002. The Department received the proof of publication on September 27, 2002.

The applicant requested, and received from the Department, two orders granting additional time in which to file a petition for an administrative hearing. On December 9, 2002, the applicant made a third such request. However, on December 20, 2002, the applicant withdrew the last request based on the revised draft permit as agreed to with the Department. There were no other requests for extensions or petitions filed on this project.

COMMENTS

EPA Region 4

Comment 1. On August 28, 2002, the Department received comments from EPA Region 4 regarding the draft permit. EPA's single comment focuses on the BACT determination for nitrogen oxides when operating in simple cycle mode. EPA notes that the applicant did not consider the option of reducing the exhaust gas temperature to within the conventional SCR catalyst operational range for running in simple cycle mode. EPA requested that the Department evaluate the technical feasibility of this option and, if technically feasible, the economics, environmental impacts, and energy use aspects of this option.

Response: The Department contacted an engineer in California's South Coast Air Quality Management District and discussed exhaust cooling for a project using a simple cycle Frame 7EA gas turbine employing a "hot" SCR catalyst. The cooling was necessary to prevent irreversible damage to the catalyst due to potential temperature excursions above 1000° F. Most conventional catalysts require an operational temperature range of approximately 400° F to 700° F, which would mean substantially higher cooling air flow rates as well as raise additional concerns regarding the potential risks for catalyst damage. The Department was unable to find a similar project for a Frame 7FA gas turbine that employed sufficient exhaust cooling to allow the use of a conventional SCR catalyst. The design basis of the FPL Martin project is to construct and operate a base-loaded, 4-on-1 combined cycle system. FPL currently operates similar base-loaded combined cycle units at the Martin Plant. FPL's request for some simple cycle operation is to accommodate possible scenarios when a HRSG or steam-electrical generator is not functional. EPA's exhaust cooling scenario could not be applied in the case where repair work had to be performed on the HRSG. The permit allows limited simple cycle operation (1000 hours/year) once construction is completed for combined cycle operation. The permitted NOx standards for this very limited simple cycle operation compare favorably with many other similar simple cycle projects. Although such cooling would be technically possible, the Department did not require the applicant to evaluate this concept further based on the specifics of this project. The Department may require such an evaluation for future projects.

Comment 2. On February 5, 2003, the Department received a letter from EPA Region 4 in response to a request for a determination of applicability of Subpart Dc with regard to the gas-fired fuel heaters. Subpart Dc is a federal New Source Performance Standard that regulates small industrial-commercial-institutional steam generating units. EPA stated that the fuel heaters are not subject to NSPS Subpart Dc.

Response: The Department concurs. Conditions related to NSPS Subpart Dc were removed from the final permit.

Applicant

The applicant provided several comments on the draft permit in writing, via email, and in person. The following summarizes many of the changes that the Department agreed to make as a result of these comments.

Cover Page: The permit expiration date is extended from 12/30/05 to 12/30/06 to provide sufficient time to construct, test, and obtain Title V operation permit. Under "Project and Location", a new note is added to clarify that references to the electrical generating capacities (MW) in the permit relate to nominal values for the given operating conditions. Throughout the remaining permit, the word "nominal" is deleted with regard to the generating capacities (MW).

Section I. General Information

Page 2, New and Modified Units: The description for Emissions Unit 013 is revised to indicate that "four" fuel heaters that comprise this unit. There are two previously permitted fuel heaters and two new fuel heaters. The description of Emissions Unit 014 is revised to clarify that this unit represents two distillate oil storage tanks, one existing tank and one new tank.

Page 2, Regulatory Classification: References to NSPS and NESHAP are removed because these unit-specific requirements are discussed under the appropriate emissions unit sections.

Page 3, Appendices: A reference is added for Appendix XS, which is the "Continuous Monitor Systems Semi-Annual Report".

Page 3, Relevant Documents: A reference is added for previously issued Permit No. PSD-FL-286.

Page 4, Condition No. 3: The condition is revised to clarify that it is necessary to demonstrate the adequacy of previous BACT determinations when construction has not commenced within 18 months or construction has been delayed for 18 months.

Section III A. Unit 8 – "4 on 1" Combined Cycle Gas Turbine

Page 5, Emissions Unit Description: Added note following stack parameters, "The Department may require the permittee to perform additional air dispersion modeling should the actual specified stack dimensions change." The flow rate was corrected for oil firing during simple cycle operation from 2,745,300 acfm to 2,464,300 acfm.

Page 5, Condition 2: The condition is updated to reflect Appendix Da and to remove the reference to Appendix Dc, which is removed.

Page 6, Condition 3: The simple cycle stack dimensions are removed because the dimensions are already provided in the emissions unit description.

Page 6, Condition 4a: To clarify that the units must be tuned to achieve the NOx and CO emission levels during simple cycle operation, the second sentence is reworded to, "Prior to the initial emissions performance tests required for each gas turbine, the DLN combustors and automated gas turbine control system shall be tuned to achieve the simple cycle permitted levels for CO and NOx emissions." Also, the following permitting note is added to clarify that there are two existing gas turbines, "Initial tuning has been completed for Emissions Unit Nos. 011 and 012."

Page 6, Condition 4b: Similar to Condition 4a above, the condition is reworded to, "The permittee shall install, operate, and maintain a water injection system to reduce NOx emissions from each gas turbine when firing distillate oil. Prior to the initial emissions performance tests required for each gas turbine, the water injection system shall be tuned to achieve the permitted levels for CO and NOx emissions. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations. The automated control system shall be programmed to establish a water-to-fuel ratio designed to achieve the NOx emission standard for simple cycle oil firing on a 1-hour basis. *{Permitting Note: Initial tuning has been completed for Emissions Unit Nos. 011 and 012.}*"

Page 6, Condition 4c: The last sentence is reworded to, "The SCR system shall be designed, constructed and operated to achieve the permitted levels for NOx emissions and ammonia slip." Also, the permitting note is reworded to, "*In* accordance with 40 CFR 60.130, the storage of ammonia shall comply with all applicable requirements of the Chemical Accident Prevention Provisions in 40 CFR 68."

Page 6, Condition 5: The HRSG stack dimensions are removed from this condition because they are already provided in the emissions unit description. The requirement to install a "stack damper" is removed because it would have little impact on the types of shutdowns expected for these base-loaded units. FPL's 2000-2001 annual operating reports for the existing 2-on-1 combined cycle Martin Units 3 and 4 show an annual capacity factor of 90% or more for the past two years. This supports FPL's claim that the new combined cycle Unit 8 will be a base-loaded unit. Therefore, the condition is reworded to, "The permittee is authorized to install, operate, and maintain four new heat recovery steam generators (HRSGs) with separate HRSG exhaust stacks. Each HRSG shall be designed to recover heat energy from one of the four gas turbines (8A-8D) and deliver steam to the steam turbine electrical generator through a common manifold. Each HRSG may be equipped with supplemental gas-fired duct burners having a maximum heat input rate of 495 MMBtu per hour (LHV). The duct burners shall be designed in accordance with the following specifications: 0.04 lb CO/MMBtu and 0.08 lb NOx/MMBtu. *{Permitting Note: The four HRSGs deliver steam to a single steam turbine-electrical generator with a generating capacity of 470 MW.}*"

Page 7, Condition 6: To clarify that the maximum heat input rate is an equipment specification, the first sentence is reworded to, "The maximum heat input rate to each gas turbine is 1600 MMBtu per hour when firing natural gas and 1811 MMBtu per hour when firing distillate oil (based on a compressor inlet air temperature of 59° F, the lower heating value (LHV) of each fuel, and 100% load)."

Page 7, Condition 7: To clarify that the maximum heat input rate is an equipment specification, the first sentence is reworded to, "The total maximum heat input rate to the duct burners for each HRSG is 495 MMBtu per hour based on the lower heating value (LHV) of natural gas."

Page 7, Condition 8d: To clarify SCR operation, the last sentence is reworded to, "In accordance with the specifications of the SCR and HRSG manufacturers, the SCR system shall be on line and functioning properly during combined cycle operation or when the HRSG is producing steam."

Page 8, Condition 8g: To clarify that the total combined operation of power augmentation and peaking modes shall not exceed 400 hours during any consecutive 12 months <u>per unit</u>, the condition is reworded to, "Total combined operation of power augmentation and peaking modes shall not exceed 400 hours per unit during any consecutive 12 months."

Page 8, Condition 8h: To satisfy the FPL's initial application request that duct firing be limited based on fuel consumption and not hours, the condition is reworded to, "The total combined heat input rate to the duct burners (all four HRSGs) shall not exceed 5,702,400 MMBtu (LHV) during any consecutive 12 months." This is the equivalent heat input rate for 2880 hours per year of duct firing, which was the previous permit requirement.

Page 8, Condition 9: The condition specifying the emissions standards are revised as follows:

- The emissions standards table is reformatted for clarity.
- Additional information is added to the note following the table, which is reworded to, "*{Permitting Notes: "DB" means duct burning. "PA" means power augmentation. "SCR" means selective catalytic reduction. "NA" means not applicable. The mass emission rate standards are based on a turbine inlet condition of 59° F and may be adjusted to actual test conditions in accordance with the performance curves and/or equations on file with the Department. Initial compliance tests under normal conditions for gas and oil firing have already been conducted for the existing Unit 8 gas turbines.}*"
- The column labeled "Initial" is revised to "Stack Test, 3-Run Averages" to clarify the basis of the standard as opposed to the adjacent column, which is labeled "CEMS". To clarify that the standards are not rolling

averages, the term "Block Averages" is added to the "CEMS" column.

- For firing natural gas, the CO emissions standards are separated into "simple cycle" and "combined cycle" operation. No change is made to the standards for simple cycle operation. For combined cycle operation, the CO standards are separated into "Normal" operation (which does not include duct firing, power augmentation, or peaking) and "All Modes" (which includes any mode of operation). For operation in any mode other than "normal", the CO CEMS standard is simplified to "10.0 ppmvd @ 15% O_2 based on a 24-hour average". The revised standard allows the operator to manage the CO emissions to comply with the permit requirements while ensuring efficient combustion and operation. The initial draft permit allowed 8 ppmvd @ 15% O_2 for operation with and without duct firing and 12 ppmvd @ 15% O_2 with power augmentation. The revised standard is equivalent to a day with 12 hours of normal operation combined with 12 hours of power augmentation at the previously permitted levels. The Department believes that the revised standard is as stringent as the original levels and represents BACT for combined cycle gas turbines.
- For firing natural gas, the averaging period of the NOx standards for simple cycle peaking and power augmentation are changed to a 24-hour average basis of hours operated in that mode. This is consistent with the way in which the CO emission standards are written. Compliance could be determined on as little as one hour of data or as much as 24 hours of data. However, it is unlikely that a unit would be operated in one of these high-power modes for more than a few hours per day. The Department believes that the revised standard is as stringent as the original levels and represents BACT for simple cycle gas turbines.
- For combined cycle operation while firing natural gas, the table format is changed similar to that for the CO standards. The NOx mass emissions rate for simple cycle peaking when firing gas is corrected from 101.3 to 95.3 lb/hour (based on turbine inlet conditions of 59° F). Similarly, the NOx mass emissions rate for combined cycle duct firing when firing natural gas is corrected from 22.1 to 23.6 lb/hour (based on turbine inlet conditions of 59° F).
- The VOC mass emissions rate for combined cycle duct burning/power augmentation when firing natural gas is corrected from 9.2 to 10.5 lb/hour (based on turbine inlet conditions of 59° F).
- Consistent with other recently issued PSD permits, the ammonia slip standard is revised from 5.0 to 5 ppmvd @ 15% O_2. Condition 9f is revised to, "Subject to the requirements of Condition No. 23 of this section, each SCR system shall be designed and operated for an initial ammonia slip target of less than 5 ppmvd corrected to 15% oxygen based on the average of three test runs."
- Conditions 9a through 9f are updated according to the changes discussed.

Page 9, Condition 10: To clarify that there is not a separate *dump* condenser, condition is reworded to, "If the steam-electrical turbine generator is off line, the permittee is authorized to operate the gas turbine/HRSG systems by dumping steam to the condenser. When operating in this manner, each unit shall comply with the standards established for combined cycle operation with ammonia injection (SCR)." The permitting note regarding inefficient operation when dumping steam is removed, as it is unnecessary.

Page 9, Condition 11: With regard to the NSPS standards for the duct burners, the following permitting note is added, "During duct firing, compliance with the limits of this permit also demonstrates compliance with the standards of NSPS Subpart Da for duct burners."

Page 10, Condition 12: To clarify the phasing-in of the combined cycle project with the two existing gas turbines, the condition is reworded to, "Until commencement of the initial steam blows, the terms and conditions of Air Permit No. PSD-FL-286 shall apply to the two existing Unit 8 gas turbines (Emissions Unit Nos. 011 and 012), the two existing gas-fired fuel heaters (Emissions Unit 013) and the distillate oil storage tank (Emissions Unit 014). Thereafter, this PSD permit shall replace and supersede Air Permit No. PSD-FL-286. *{Permitting Note: Initial tests on gas and oil under normal conditions during simple cycle operation have already been conducted for the existing Unit 8 gas turbines.}*"

Page 10, Condition 16: The applicant provided additional information regarding startup of the 4-on-1 combined cycle unit when the steam turbine electrical generator is cold. For such a startup, it is imperative that the steam turbine be gradually warmed up before full load operation to prevent thermal metal fatigue and premature failure. (Similarly, it may be necessary to gradually cool the system during a shutdown.) The relatively unique combination of four gas turbine/HRSG systems supplying steam to a common steam turbine further complicates such startups. The procedure begins with the startup of a single gas turbine/HRSG system operating at very low loads (< 10%). This unit may operate under these conditions from four to six hours depending on the length of shutdown and the steam turbine temperature. Approximately two to three hours into the cold steam turbine startup, a second gas turbine/HRSG system is brought on line under the low load conditions. The third and fourth gas turbine/HRSG systems are eventually brought on line in a similar manner. The entire steam turbine cold startup is complete within 12 hours.

Cycling such units through the range of low temperatures to high temperatures increases the risk of equipment failure. Such operation also increases the frequency of maintenance intervals, which adds to operating costs. Therefore, operators of base-loaded units have every incentive to minimize the frequency of cold steam turbine startups and shutdowns. For example, FPL recently re-powered the Ft. Myers plant with a similar 4-on-1 combined cycle gas turbine system. The unit has been operating approximately six months and has had but one cold steam turbine startup.

The Department's rules require that the duration of excess emissions due to startup, shutdown, or malfunction be minimized, but that, "... in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration." Although emission concentrations can be much higher than permitted standards during startups, operation at such low loads also means less fuel consumption, mass flow rates, and lower mass emission rates. Considering all of this information the, the condition is revised to:

"16. <u>Excess Emissions Allowed</u>: As specified in this condition, excess emissions resulting from startup, shutdown, oil-to-gas fuel switches and documented malfunctions are allowed provided that operators employ the best operational practices to minimize the amount and duration of emissions during such incidents. A "documented malfunction" means a malfunction that is documented within one working day of detection by contacting the Compliance Authority by telephone, facsimile transmittal, or electronic mail. For each gas turbine/HRSG system, excess emissions resulting from startup, shutdown, or documented malfunctions shall not exceed two hours in any 24-hour period except for the following specific cases.

a. For cold startup of the steam turbine system, excess emissions from any gas turbine/HRSG system shall not exceed six hours in any 24-hour period. Cold startup of the steam turbine system shall be completed within twelve hours. A cold "startup of the steam turbine system" is defined as startup of the 4-on-1 combined cycle system following a shutdown of the steam turbine lasting at least 48 hours. *{Permitting Note: During a cold startup of the steam turbine system, each gas turbine/HRSG system is sequentially brought on line at low load to gradually increase the temperature of the steam-electrical turbine and prevent thermal metal fatigue. Note that shutdowns and documented malfunctions are separately regulated in accordance with the requirements of this condition.}*

b. For shutdown of the steam turbine system, excess emissions from any gas turbine/HRSG system shall not exceed three hours in any 24-hour period.

c. For cold startup of a gas turbine/HRSG system, excess emissions shall not exceed four hours in any 24-hour period. "Cold startup of a gas turbine/HRSG system" is defined as a startup after the pressure in the high-pressure (HP) steam drum falls below 450 psig for at least a one-hour period.

d. For oil-to-gas fuel switching in simple cycle operation, excess emissions shall not exceed 1 hour in any 24-hour period.

Ammonia injection shall begin as soon as operation of the gas turbine/HRSG system achieves the operating parameters specified by the manufacturer. As authorized by Rule 62-210.700(5), F.A.C., the above conditions allow excess emissions only for specifically defined periods of startup, shutdown, and documented malfunction of the gas turbines. [Design; Rules 62-212.400(BACT) and 62-210.700, F.A.C.]"

The above revised condition adds a definition for "documented malfunction", which was inadvertently omitted from the original condition. Also, the original condition limiting "warm startups" is replaced with one limiting "cold gas turbine/HRSG startups", which is more appropriate. Finally, there is a new allowance for excess emissions due to an oil-to-gas fuel switch. This type of switch requires the unit to be brought down to low loads and cycled back through the lean premix combustion stages, which can lead to a brief period of excess emissions. Conversely, a gas-to-oil fuel switch can occur readily as oil is added and the water injection system is initiated. Therefore, one hour of excess emissions in any 24-hour period is allowed due to an oil-to-gas fuel switch. The revisions are based on the unique equipment design for this project and are not expected to result in any increased incidents of excess emissions due to startup, shutdown, malfunction, or fuel switches.

Page 10, Condition 17: The following text is added to the first paragraph, "For good cause, the permittee may request that the Compliance Authority extend the steam blow period." The notification period is changed from "24-hours" to "one working day". Also, the following sentence is added to the permitting note, "This condition only applies if simple cycle operation begins prior to combined cycle operation and NSPS compliance tests for simple cycle operation have been performed."

Page 11, Condition 19: EPA Method 5 is removed, as this test is not required by permit.

Page 12, Condition 20: To reflect the NSPS requirements for conducting initial tests, the second sentence is revised to, "The tests shall be conducted within 60 days after achieving the maximum production rate at which the unit will be operated for each unit configuration (i.e., simple cycle and combined cycle operation), but not later than 180 days after the initial startup of each unit configuration." In the third sentence, the phrase "(or fuel measurements and approved F-factors)" is substituted for the words "and calculations" to clarify the meaning. The last sentence is revised to, "The Department may require the permittee to conduct additional tests after major replacement or major repair of any air pollution control equipment, such as the SCR catalyst, DLN combustors, etc."

Page 12, New Condition 23: The following new condition is inserted as Condition No. 23.

"23. Additional Ammonia Slip Testing: If the tested ammonia slip rate for a gas turbine exceeds 5 ppmvd corrected to 15% oxygen when firing natural gas during the annual test, the permittee shall:

a. Begin testing and reporting the ammonia slip for each subsequent calendar quarter;

b. Before the ammonia slip exceeds 7 ppmvd corrected to 15% oxygen, take corrective actions that result in lowering the ammonia slip to less than 5 ppmvd corrected to 15% oxygen; and

c. Test and demonstrate that the ammonia slip is no more than 5 ppmvd corrected to 15% oxygen within 15 days after completing the corrective actions.

Corrective actions may include, but are not limited to, adding catalyst, replacing catalyst, or other SCR system maintenance or repair. After demonstrating that the ammonia slip level is no more than 5 ppmvd corrected to 15% oxygen, testing and reporting shall resume on an annual basis. [Rules 62-4.070(3) and 62-297.310(7)(b), F.A.C.]"

The new condition requires the permittee to take corrective action should the ammonia slip exceed 5 ppmvd @ 15% O_2 and begin more frequent monitoring. Note that all of the subsequent conditions are renumbered accordingly.

Page 12, Condition 23(24): Original condition 23 is renumbered to "24". Minor rewording to, "Each monitoring system shall be installed, calibrated, and properly functioning prior to the initial performance tests. Within one working day of discovering emissions in excess of a CO or NOx standard (and subject to the specified averaging period), the permittee shall notify the Compliance Authority."

24a: This condition is reworded to clarify that the CO monitor span values must be set appropriately considering the allowable methods of operation and corresponding emission standards.

24b: This condition is reworded to clarify that the NOx monitor is to be certified in accordance with the acid rain requirements (acid rain) and shall also be used for compliance with the permit emissions standards.

24c: The acid rain program requires the use of a diluent monitor, which can be either oxygen or carbon dioxide. The condition is reworded to clarify that such diluent monitors shall be certified in accordance with 40 CFR 75, which is part of the acid rain monitoring program.

24d: The following sentence is added, "For purposes of determining compliance with the CEMS emissions standards of this permit, missing (or excluded) data shall not be substituted." The acid rain program allows data substitution for determining the long-term NOx emission rates; however, this is not appropriate for determining compliance with short-term averages. To clarify the appropriate standard when two fuels are fired within the same 1-hour block, the following sentence is added, "An hour in which any oil is fired is attributed towards compliance with the permit standards for oil firing."

24g: The first two sentences are revised to, "Each CEMS shall monitor and record emissions during all operations including episodes of startup, shutdown, malfunction, fuel switches, DLN tuning, and steam blows. CEMS emissions data recorded during some of these episodes may be excluded from the corresponding CEMS compliance demonstration subject to the provisions of Condition Nos. 16 and 18 of this section." This is just a minor rewording to clarify the episodes covered.

24h: The last sentence is revised as follows to add the trailing clause, "Failure to take corrective actions or continued failure to achieve the minimum monitor availability shall be violations of this permit, except as otherwise authorized by the Department's Compliance Authority."

The term "Subpart Da" is added to the regulatory requirements in the permitting note.

Page 14, Condition 24(25): Original condition 24 is renumbered to "25". The following sentence is added, "The NOx CEMS is used to demonstrate compliance with the NOx emissions standards." The following sentence is added to the permitting note, "The actual water-to-fuel ratio will vary depending on operating conditions and load."

Page 14, Condition 26(27): Original condition 26 is renumbered to "27". The first sentence is revised to, "The permittee shall monitor and record the operating rate of each gas turbine and HRSG duct burner system on a daily average basis, considering the number of hours of operation during each day (including the times of startup, shutdown and malfunction)."

Page 15, Condition 29(30): Original condition 29 is renumbered to "30". Consistent with Rules 62-4.130 and 62-210.700(6), F.A.C., this condition is reworded to, "Within one working day of a malfunction that causes emissions in excess of a standard (subject to the specified averaging periods), the permittee shall notify the Compliance Authority. The notification shall include a preliminary report of: the nature, extent, and duration of the emissions; the probable cause of the emissions; and the actions taken to correct the problem. If requested by the Compliance Authority, the permittee shall submit written quarterly reports the malfunctions."

<u>Section III B. Gas-Fired Fuel Heaters</u>: Based on EPA Region 4's interpretation, all references to NSPS Subpart Dc were removed and replaced with the following permitting note.

{Permitting Note: FPL requested a determination from the Department on the applicability of NSPS Subpart Dc to the gas-fired fuel heaters. The Department agreed with FPL that it did not believe that

Subpart Dc should apply to these units, but referred the request to EPA Region 4 for interpretation of the federal standards. In a letter dated February 5, 2003, EPA Region 4 concurred that Subpart Dc did not apply to the gas-fired fuel heaters.}

Section III C. Cooling Tower: Condition 2 is revised to clarify that the cooling tower will be designed to achieve the specified drift rate. The permittee is also required provide a certification of this requirement.

Section III D. Distillate Storage Tank: This new subsection is added to identify the requirements from previous Air Permit No. PSD-FL-286, which this new PSD permit will eventually replace. The conditions and descriptions clarify there will be two, 2.1 million gallon distillate oil storage tanks (one existing tank and one new tank). Both tanks are available for the Unit 8 combined cycle system.

Section IV. Appendices

Appendix A (NSPS General Provisions): A new appendix added that lists the individual general provisions for NSPS units.

Appendix BD (BACT Determinations and Emissions Standards): The appendix is updated to reflect any changes in the emissions standards made in the draft permit, which were previously discussed.

Appendix Da (Duct Burners): The appendix is completely updated to reflect a more thorough presentation of the Subpart Da requirements. In general, the duct burners are subject to a NOx standard of 1.6 lb/MW-hr gross energy output. An initial compliance test is required. Thereafter, compliance with the BACT standard (2.5 ppmvd @ 15% O_2) will be adequate to show compliance with the NSPS standard.

Appendix Dc (Gas-Fired Fuel Heaters): Appendix Dc is deleted because the gas-fired fuel heaters are not subject to NSPS Subpart Dc.

Appendix GG (Gas Turbines): Appendix GG is completely updated to reflect a more thorough presentation of the Subpart GG requirements, which is similar to other recently issued PSD permits.

Appendix XS (Semiannual NSPS Excess Emissions Report): At the request of the applicant, the NSPS report format was added for the reporting emissions in excess of the NSPS standards.

Other Comments

No comments were received from the Department's Southeast District Office, the National Park Service, or the public.

REVISED DRAFT PERMIT

Based on comments made by the applicant, the Department agreed to the above changes. The changes were not considered substantial. On December 10, 2002, the revised draft permit was submitted to the Department's Siting Office for inclusion in the draft power plant site certification. A copy of the revised draft permit and a summary of the proposed changes were provided to EPA Region 4 by email on December 11, 2002. On December 31, 2002, EPA Region 4 contacted the Department by email and indicated that it had no additional comments on the proposed changes to the draft permit. The revised draft permit and a summary of the changes were posted on the Department's web site. The draft certification document (including the revised PSD permit conditions) was presented at the site certification hearing held on April 8, 2003. The project received no adverse comments regarding air quality. A final order for site certification was issued on April 11, 2003.

CONCLUSION

The final action of the Department is to issue the final permit as presented at the site certification hearing. Note that conditions regarding NSPS Subpart Dc were removed because EPA determined that this Subpart was not applicable to the fuel heaters.

Department of Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
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Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

PERMITTEE:

Florida Power and Light Company
P.O. Box 176
Indiantown, FL 34956

Authorized Representative:
John M. Lindsay, Plant General Manager

FPL Martin Power Plant
Project No. 0850001-010-AC
Air Permit No. PSD-FL-327
SIC No. 4911
Expires: December 30, 2006

PROJECT AND LOCATION

This permit authorizes the construction of Unit 8 at the existing Martin Power Plant, a "4-on-1" combined cycle unit with an electrical generating capacity of approximately 1150 MW. The project will utilize two existing 170 MW gas turbine-electrical generator sets and will add two new 170 MW gas turbine-electrical generator sets, four new heat recovery steam generators, a single 470 MW steam turbine-electrical generator, gas-fired fuel heaters, and a mechanical draft cooling tower. The existing Martin Power Plant is located approximately 7 miles north of Indiantown on State Road 710 in Martin County, Florida. *{Permitting Note: Throughout this permit, the electrical generating capacities represent nominal values for the given operating conditions.}*

STATEMENT OF BASIS

This PSD air pollution construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.) and Title 40 Part 60 of the Code of Federal Regulations. The project was processed in accordance with the requirements of Rule 62-212.400, F.A.C., the preconstruction review program for the Prevention of Significant Deterioration (PSD) of Air Quality. Pursuant to Chapter 62-17, F.A.C. and Chapter 403 Part II, F.S., the project is also subject to Electrical Power Plant Siting. The permittee is authorized to install the proposed equipment 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.

CONTENTS

Howard L Rhodes   4/16/03

Howard L. Rhodes, Director   (Date)
Division of Air Resources Management

FACILITY DESCRIPTION

The existing Martin Power Plant currently consists of six electrical generating units. Fossil fuel-fired steam electric generating Units 1 and 2 (863 MW each) began operation in 1980 and 1981, respectively. Combined cycle gas turbine Units 3 and 4 (430 MW each) began operation in 1994. Two existing Unit 8 simple cycle gas turbines (170 MW each) began operation in 2001. The existing Unit 8 gas turbines will be incorporated into the new "4 on 1" combined cycle Unit 8, which will consist of two new gas turbines (170 MW each), four heat recovery steam generators, a single steam turbine-electrical generator (470 MW), and a mechanical draft cooling tower. New combined cycle Unit 8 will have a total generating capacity of approximately 1150 MW. After completion of this project, the plant will have a total generating capacity of approximately 3610 MW.

NEW AND MODIFIED EMISSIONS UNITS

This permit authorizes construction and installation of the following new emissions units.

ID	Emission Unit Description
011	Unit 8A gas turbine (170 MW) with heat recovery steam generator
012	Unit 8B gas turbine (170 MW) with heat recovery steam generator
013	Four gas-fired fuel heaters
014	Two distillate oil storage tanks for Unit 8 gas turbines
017	Unit 8C gas turbine (170 MW) with heat recovery steam generator
018	Unit 8D gas turbine (170 MW) with heat recovery steam generator
019	Mechanical draft cooling tower for Unit 8

Note: Martin Unit 8 consists of four gas turbine-electrical generator sets (Units 8A-8D), four gas-fired heat recovery steam generators (HRSGs), and a single steam-turbine electrical generator.

REGULATORY CLASSIFICATION

Title III: The existing facility is major for hazardous air pollutants (HAPs). This project is not major for HAPs.

Title IV: The facility operates emissions units subject to the acid rain provisions of the Clean Air Act.

Title V: Because potential emissions of at least one regulated pollutant exceed 100 tons per year, the existing facility is a Title V major source of air pollution in accordance with Chapter 62-213, F.A.C. Regulated pollutants include pollutants such as carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), and volatile organic compounds (VOC).

PSD: The project is located in an area designated as "attainment" or "unclassifiable" for each pollutant subject to a National Ambient Air Quality Standard. The facility is considered a "fossil fuel fired steam electric plant of more than 250 million BTU per hour of heat input", which is one of the 28 PSD source categories with the lower PSD applicability threshold of 100 tons per year. Potential emissions of at least one regulated pollutant exceed 100 tons per year. Therefore, the facility is classified as a PSD-major source of air pollution with respect to Rule 62-212.400, F.A.C, the Prevention of Significant Deterioration (PSD) of Air Quality.

Siting: The project is subject to Electrical Power Plant Siting in accordance with Chapter 62-17, F.A.C. and Chapter 403, Part II, F.S.

PERMITTING AUTHORITY

All documents related to applications for permits to construct, operate or modify an emissions unit shall be submitted to the Bureau of Air Regulation of the Florida Department of Environmental Protection (DEP) at

2600 Blair Stone Road (MS #5505), Tallahassee, Florida 32399-2400. Copies of all such documents shall also be submitted to the Compliance Authority.

COMPLIANCE AUTHORITY

All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Air Resources Section of the Southeast District Office, Florida Department of Environmental Protection, Post Office Box 15425, West Palm Beach, Florida 33416-5425.

APPENDICES

The following Appendices are attached as part of this permit.

Appendix A. NSPS Subpart A, Identification of General Provisions

Appendix BD. Final BACT Determinations and Emissions Standards

Appendix CF. Citation Format and Definitions

Appendix Da. NSPS Subpart Da Requirements for Duct Burners

Appendix GC. General Conditions

Appendix GG. NSPS Subpart GG Requirements for Gas Turbines

Appendix SC. Standard Conditions

Appendix XS. Semiannual NSPS Excess Emissions Report

RELEVANT DOCUMENTS

The documents listed below are not a part of this permit; however, they are specifically related to this permitting action and are on file with the Department.

- Previously issued Air Permit No. PSD-FL-286 for the existing Unit 8 simple cycle gas turbines;
- Permit application received on 02/01/02 and all related completeness correspondence;
- Draft permit package issued on July 31, 2002;
- Comments received regarding draft permit;
- Draft permit revised due to comments; and
- Final order issued by the Siting Board.

1. General Conditions: The permittee shall operate under the attached General Conditions listed in Appendix GC of this permit. General Conditions are binding and enforceable pursuant to Chapter 403 of the Florida Statutes. [Rule 62-4.160, F.A.C.]

2. Applicable Regulations, Forms and Application Procedures: Unless otherwise indicated in this permit, the construction and operation of the subject emissions unit shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of: Chapter 403 of the Florida Statutes (F.S.); Chapters 62-4, 62-204, 62-210, 62-212, 62-213, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.); and the Title 40, Parts 51, 52, 60, 72, 73, and 75 of the Code of Federal Regulations (CFR), adopted by reference in Rule 62-204.800, F.A.C. The terms used in this permit have specific meanings as defined in the applicable chapters of the Florida Administrative Code. 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. Issuance of this permit does not relieve the permittee from compliance with any applicable federal, state, or local permitting or regulations. [Rules 62-204.800, 62-210.300 and 62-210.900, F.A.C.]

3. Construction and Expiration: The permit expiration date includes sufficient time to complete construction, perform required testing, submit test reports, and submit an application for a Title V operation permit to the Department. Approval to construct shall become invalid for any of the following reasons: construction is not commenced within 18 months after issuance of this permit; construction is discontinued for a period of 18 months or more; or 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. In conjunction with an extension of the 18-month period to commence or continue construction (or to construct the project in phases), the Department may require the permittee to demonstrate the adequacy of any previous determination of Best Available Control Technology (BACT) for emissions units regulated by the project. For good cause, the permittee may request that this PSD air-construction permit be extended. Such a request shall be submitted to the Department's Bureau of Air Regulation at least sixty (60) days prior to the expiration of this permit. [Rules 62-4.070(4), 62-4.080, 62-210.300(1), and 62-212.400(6)(b), F.A.C.; 40 CFR 52.21(r)(2); 40 CFR 51.166(j)(4)]

4. New or Additional Conditions: 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.]

5. Modifications: No emissions unit or facility subject to this permit shall be constructed or modified without obtaining an air construction permit from the Department. Such permit shall be obtained prior to beginning construction or modification. [Chapters 62-210 and 62-212, F.A.C.]

6. Application for Title IV Permit: At least 24 months before the date on which the new unit begins serving an electrical generator greater than 25 MW, the permittee shall submit an application for a Title IV Acid Rain Permit to the Department's Bureau of Air Regulation in Tallahassee and a copy to the Region 4 Office of the U.S. Environmental Protection Agency in Atlanta, Georgia. [40 CFR 72]

7. Title V Permit: This permit authorizes construction of the permitted emissions units and initial operation to determine compliance with Department rules. A Title V operation permit is required for regular operation of the permitted emissions unit. The permittee shall apply for a Title V operation permit at least 90 days prior to expiration of this permit, but no later than 180 days after commencing operation. To apply for a Title V operation permit, the applicant shall submit the appropriate application form, compliance test results, and such additional information as the Department may by law require. The application shall be submitted to the Department's Bureau of Air Regulation with a copy to the Compliance Authority. [Rules 62-4.030, 62-4.050, 62-4.220 and Chapter 62-213, F.A.C.]

A. UNIT 8 COMBINED CYCLE GAS TURBINE (EUs 011, 012, 017, AND 018)

This section of the permit addresses the following emissions units.

Emissions Units 011, 012, 017, 018

Description: Emissions units 011, 012, 017, and 018 each consist of a General Electric Model PG7241(FA) gas turbine-electrical generator set, an automated gas turbine control system, an inlet air filtration system, an evaporative inlet air-cooling system, a gas-fired heat recovery steam generator (HRSG), a bypass stack, a HRSG stack, and associated support equipment. In addition, the project also includes a single steam turbine-electrical generator that serves all four gas turbine/HRSG systems.

Fuels: Each gas turbine fires natural gas as the primary fuel and distillate oil as a restricted alternate fuel.

Generating Capacity: Each of the four gas turbine-electrical generator sets has a generating capacity of 170 MW for gas firing (180 MW for oil firing). Exhaust from each gas turbine passes through a separate heat recovery steam generator (HRSG). Steam from each HRSG is delivered to the single steam turbine-electrical generator, which has a generating capacity of 470 MW. The total generating capacity of the "4 on 1" combined cycle unit is approximately 1150 MW.

Controls: The efficient combustion of natural gas and restricted firing of low sulfur distillate oil minimizes the emissions of CO, PM/PM_{10}, SAM, SO_2 and VOC. Dry low-NOx (DLN) combustion technology for gas firing and water injection for oil firing reduce NOx emissions during simple cycle operation. A selective catalytic reduction (SCR) system in combination with the other NOx controls further reduces NOx emissions during combined cycle operation.

Stack Parameters: Each gas turbine has a bypass stack (80 feet tall and 22.0 feet in diameter) and each heat recovery steam generator has a HRSG stack (120 feet tall and 19.0 feet in diameter). The Department may require the permittee to perform additional air dispersion modeling should the actual specified stack dimensions change. The following summarizes the exhaust characteristics:

			Simple Cycle Operation		Combined Cycle Operation	
Fuel	Heat Input Rate (LHV)	Compressor Inlet Temp.	Exhaust Temp.	Flow Rate ACFM	Exhaust Temp., °F	Flow Rate ACFM
Gas	1600 MMBtu/hour	59° F	1116° F	2,389,500	202° F	1,004,200
Oil	1811 MMBtu/hour	59° F	1098° F	2,464,300	295° F	1,193,900

Continuous Monitors: Each stack is equipped with continuous emissions monitoring systems (CEMS) to measure and record CO and NOx emissions as well as flue gas oxygen or carbon dioxide content.

APPLICABLE STANDARDS AND REGULATIONS

1. BACT Determinations: Determinations of the Best Available Control Technology (BACT) were made for carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM_{10}), sulfuric acid mist (SAM), and sulfur dioxide (SO_2), and volatile organic compounds (VOC). See Appendix BD of this permit for a summary of the final BACT determinations. [Rule 62-212.400(BACT), F.A.C.]

2. NSPS Requirements: The Department determines that compliance with the BACT emissions performance and monitoring requirements also assures compliance with the New Source Performance Standards for Subpart Da (duct burners) and Subpart GG (gas turbines) in 40 CFR 60. For completeness, the applicable requirements of Subparts Da and GG are included in Appendices Da and GG of this permit. [Rule 62-204.800(7), F.A.C.]

EQUIPMENT

3. Gas Turbines: The permittee is authorized to install, tune, operate, and maintain four General Electric Model PG7241FA gas turbine-electrical generator sets each with a generating capacity of 170 MW. Each gas turbine shall include the Speedtronic™ automated gas turbine control system and have dual-fuel capability. Ancillary equipment includes an inlet air filtration system, an evaporative inlet air-cooling system, and a bypass stack for simple cycle operation. The gas turbines will utilize the "hot nozzle" DLN combustors, which require natural gas to be preheated to approximately 290° F before combustion to increase overall unit efficiency. Gas-fired fuel heaters will preheat the natural gas during simple cycle operation and during startup to combined cycle operation. For full combined cycle operation, feedwater heat exchangers will preheat the natural gas. *{Permitting Note: In accordance with Air Permit No. PSD-FL-286, two existing simple cycle gas turbines (Emission Unit Nos. 011 and 012) have been installed. These units will be incorporated into the "4-on-1" combined cycle Unit 8.}* [Application; Design]

4. Gas Turbine NOx Controls

   a. *DLN Combustion*: The permittee shall operate and maintain the General Electric DLN 2.6 combustion system (or better) to control NOx emissions from each gas turbine when firing natural gas. Prior to the initial emissions performance tests required for each gas turbine, the DLN combustors and automated gas turbine control system shall be tuned to achieve the simple cycle permitted levels for CO and NOx emissions. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations. *{Permitting Note: Initial tuning has been completed for Emissions Unit Nos. 011 and 012.}*

   b. *Water Injection*: The permittee shall install, operate, and maintain a water injection system to reduce NOx emissions from each gas turbine when firing distillate oil. Prior to the initial emissions performance tests required for each gas turbine, the water injection system shall be tuned to achieve the permitted levels for CO and NOx emissions. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations. The automated control system shall be programmed to establish a water-to-fuel ratio designed to achieve the NOx emission standard for simple cycle oil firing on a 1-hour basis. *{Permitting Note: Initial tuning has been completed for Emissions Unit Nos. 011 and 012.}*

   c. *(SCR) System*: The permittee shall install, tune, operate, and maintain a selective catalytic reduction (SCR) system to control NOx emissions from each gas turbine during combined cycle operation when firing either natural gas or distillate oil. The SCR system consists of an ammonia injection grid, catalyst, ammonia storage, monitoring and control system, electrical, piping and other ancillary equipment. The SCR system shall be designed, constructed and operated to achieve the permitted levels for NOx emissions and ammonia slip. *{Permitting Note: In accordance with 40 CFR 60.130, the storage of ammonia shall comply with all applicable requirements of the Chemical Accident Prevention Provisions in 40 CFR 68.}*

   [Design; Rule 62-212.400(BACT), F.A.C.]

5. HRSGs: The permittee is authorized to install, operate, and maintain four new heat recovery steam generators (HRSGs) with separate HRSG exhaust stacks. Each HRSG shall be designed to recover heat energy from one of the four gas turbines (8A-8D) and deliver steam to the steam turbine electrical generator through a common manifold. Each HRSG may be equipped with supplemental gas-fired duct burners having a maximum heat input rate of 495 MMBtu per hour (LHV). The duct burners shall be designed in accordance with the following specifications: 0.04 lb CO/MMBtu and 0.08 lb NOx/MMBtu. *{Permitting Note: The four HRSGs deliver steam to a single steam turbine-electrical generator with a generating capacity of 470 MW.}* [Application; Design]

PERFORMANCE RESTRICTIONS

6. Permitted Capacity - Gas Turbines: The maximum heat input rate to each gas turbine is 1600 MMBtu per hour when firing natural gas and 1811 MMBtu per hour when firing distillate oil (based on a compressor inlet air temperature of 59° F, the lower heating value (LHV) of each fuel, and 100% load). Heat input rates will vary depending upon gas turbine characteristics, ambient conditions, alternate methods of operation, and evaporative cooling. The permittee shall provide manufacturer's performance curves (or equations) that correct for site conditions to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department. [Rule 62-210.200(PTE), F.A.C.]

7. Permitted Capacity - HRSG Duct Burners: The total maximum heat input rate to the duct burners for each HRSG is 495 MMBtu per hour based on the lower heating value (LHV) of natural gas. Only natural gas shall be fired in the duct burners. [Rule 62-210.200(PTE), F.A.C.]

8. Methods of Operation: Subject to the restrictions and requirements of this permit, the gas turbines may operate under the following methods of operation.

   a. *Hours of Operation*: Subject to the operational restrictions of this permit, the gas turbines may operate throughout the year (8760 hours per year). Restrictions on individual methods of operation are specified below.

   b. *Authorized Fuels*: Each gas turbine shall fire natural gas as the primary fuel, which shall contain no more than 2.0 grains of sulfur per 100 standard cubic feet of natural gas. As a restricted alternate fuel, each gas turbine may fire No. 2 distillate oil (or a superior grade) containing no more than 0.05% sulfur by weight. Each gas turbine shall fire no more than 500 hours of distillate oil during any consecutive 12 months.

   c. *Simple Cycle Operation*: Each gas turbine may operate individually in simple cycle mode to produce only direct, shaft-driven electrical power subject to the following operational restrictions.

      (1) Each gas turbine shall operate in simple cycle mode for no more than 3390 hours during any consecutive 12 months.

      (2) After demonstrating initial compliance in combined cycle mode, the combined group of four gas turbines shall operate in simple cycle mode for no more than an average of 1000 hours per gas turbine during any consecutive 12 months.

   d. *Combined Cycle Operation*: Each gas turbine/HRSG system may operate to produce direct, shaft-driven electrical power and steam-generated electrical power from the steam turbine-electrical generator as a four-on-one combined cycle unit subject to the restrictions of this permit. In accordance with the specifications of the SCR and HRSG manufacturers, the SCR system shall be on line and functioning properly during combined cycle operation or when the HRSG is producing steam.

   e. *Inlet Fogging*: In accordance with the manufacturer's recommendations and appropriate ambient conditions, the evaporative cooling system may be operated to reduce the compressor inlet air temperature and provide additional direct, shaft-driven electrical power. This method of operation is commonly referred to as "fogging" and may be used in either simple cycle or combined cycle modes.

   f. *Peaking*: When firing natural gas, each gas turbine may operate in a high-temperature peaking mode to generate additional direct, shaft-driven electrical power to respond to peak demands. During any consecutive 12 months, each gas turbine shall operate while in the peaking mode for no more than 60 hours of simple cycle operation and no more than 400 hours of combined cycle operation.

g. *Power Augmentation*: When firing natural gas in either simple cycle or combined cycle modes, steam may be injected into each gas turbine to generate additional direct, shaft-driven electrical power to respond to peak demands. To qualify as "power augmentation", the combustion turbine must operate at a load of 95% or greater than that of the manufacturer's maximum base load rate adjusted for the compressor inlet air conditions. Prior to activating and after deactivating the power augmentation mode, the operator shall log the date, time, and new mode of operation. The gas turbines shall not operate simultaneously in peaking and power augmentation modes. Total combined operation of power augmentation and peaking modes shall not exceed 400 hours per unit during any consecutive 12 months.

h. *Combined Cycle Operation with HRSG Duct Firing*: When firing natural gas and operating in combined cycle mode, each HRSG system may fire natural gas in the duct burners to provide additional steam-generated electrical power. The total combined heat input rate to the duct burners (all four HRSGs) shall not exceed 5,702,400 MMBtu (LHV) during any consecutive 12 months.

[Application; Rules 62-210.200(PTE) and 62-212.400(BACT), F.A.C.]

EMISSIONS STANDARDS

9. <u>Emissions Standards</u>: Emissions from each gas turbine shall not exceed the following standards.

Pollutant	Fuel	Method of Operation	Stack Test, 3-Run Average		CEMS Block Average
			ppmvd @ 15% O_2	lb/hour	ppmvd @ 15% O_2
CO [a]	Oil	Simple or Combined Cycle	14.4	64.7	15.0, 24-hr
	Gas	Simple Cycle	7.4	27.5	8.0, 24-hr
		Simple Cycle w/PA	12.0	45.0	12.0, 24-hr
		Combined Cycle, Normal	7.4	27.5	10.0, 24-hr
		Combined Cycle, All Modes	NA	NA	
NOx [b]	Oil	Simple Cycle	42.0	319.2	42.0, 3-hr
		Combined Cycle w/SCR	10.0	76.0	10.0, 24-hr
	Gas	Simple Cycle	9.0	58.7	9.0, 24-hr
		Simple Cycle w/PA	12.0	76.2	12.0, 24-hr
		Simple Cycle w/Peaking	15.0	95.3	15.0, 24-hr
		Combined Cycle w/SCR, Normal	2.5	16.3	2.5, 24-hr
		Combined Cycle w/SCR and DB	2.5	23.6	
		Combined Cycle w/SCR, All Modes	NA	NA	
PM/PM10 [c]	Oil/Gas	Simple or Combined Cycle	Fuel Specifications		
		Simple or Combined Cycle	Visible emissions shall not exceed 10% opacity for each 6-minute block average.		
SAM/SO_2 [d]	Oil/Gas	Simple or Combined Cycle	Fuel Specifications		
VOC [e]	Oil	Simple or Combined Cycle	2.5	6.0	NA
	Gas	Simple or Normal Combined Cycle	1.3	2.8	NA
		Combined Cycle, w/DB and/or PA	4.0	10.5	NA
Ammonia [f]	Oil/Gas	Combined Cycle w/SCR	5	NA	NA

a. Compliance with the CO standards shall be demonstrated based on data collected by the required CEMS. Compliance may also be determined by EPA Method 10. Compliance with the 24-hour CO CEMS standards shall be determined separately for each method of operation based on the hours of operation for each method. *{Permitting Note: A 24-hour compliance average may be based on as little as 1-hour of CEMS data or as much as 24-hours of CEMS data.}*

b. Compliance with the NOx standards shall be demonstrated based on data collected by the required CEMS. Compliance may also be determined by EPA Method 7E or 20. NOx mass emission rates are defined as oxides of nitrogen expressed as NO_2. Compliance with the 24-hour NOx CEMS standards during simple cycle operation shall be determined separately for each method of operation based on the hours of operation for each method. *{Permitting Note: A 24-hour compliance average may be based on as little as 1-hour of CEMS data or as much as 24-hours of CEMS data.}*

c. The fuel specifications established in Condition No. 8 of this section combined with the efficient combustion design and operation of each gas turbine represents the Best Available Control Technology (BACT) determination for PM/PM_{10} emissions. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion. Compliance with the fuel specifications shall be demonstrated by keeping records of the fuel sulfur content. Compliance with the visible emissions standard shall be demonstrated by conducting tests in accordance with EPA Method 9. *{Permitting Note: PM_{10} emissions for gas firing are estimated at 9 lb/hour for simple cycle operation, 11 lb/hour for combined cycle operation, and 17 lb/hour for combined cycle operation with duct burning. PM_{10} emissions for oil firing are estimated at 17 lb/hour for simple cycle operation and 37 lb/hour for combined cycle operation.}*

d. The fuel sulfur specifications in Condition No. 8 of this section effectively limit the potential emissions of SAM and SO_2 from the gas turbines and represent the Best Available Control Technology (BACT) determination for these pollutants. Compliance with the fuel sulfur specifications shall be determined by the requirements in Condition No. 29 of this section. *{Permitting Note: SO_2 emissions for gas firing are estimated at 9.8 lb/hour for simple and combined cycle operation and 12.8 lb/hour for combined cycle operation with duct burning. SO_2 emissions for oil firing are estimated at 99 lb/hour for simple and combined cycle operation. SAM emissions are estimated to be less than 10% of the SO_2 emissions.}*

e. Compliance with the VOC standards shall be demonstrated by conducting tests in accordance with EPA Method 25A. Optionally, EPA Method 18 may also be performed to deduct emissions of methane and ethane. The emission standards are based on VOC measured as methane.

f. Subject to the requirements of Condition No. 23 of this section, each SCR system shall be designed and operated for an initial ammonia slip target of less than 5 ppmvd corrected to 15% oxygen based on the average of three test runs. Compliance with the ammonia slip standard shall be demonstrated by conducting tests in accordance with EPA Method CTC-027.

{Permitting Notes: "DB" means duct burning. "PA" means power augmentation. "SCR" means selective catalytic reduction. "NA" means not applicable. The mass emission rate standards are based on a turbine inlet condition of 59° F and may be adjusted to actual test conditions in accordance with the performance curves and/or equations on file with the Department. Initial compliance tests under normal conditions for gas and oil firing have already been conducted for the existing Unit 8 gas turbines.}

[Rule 62-212.400(BACT), F.A.C.]

10. <u>Combined Cycle Operation With Steam Dumped to Condenser</u>: If the steam-electrical turbine generator is off line, the permittee is authorized to operate the gas turbine/HRSG systems by dumping steam to the condenser. When operating in this manner, each unit shall comply with the standards established for

combined cycle operation with ammonia injection (SCR). [Application]

11. Duct Burners: The duct burners are also subject to the provisions of Subpart Da of the New Source Performance Standards in 40 CFR 60, which are summarized in Appendix Da. *{Permitting Note: During duct firing, compliance with the limits of this permit also demonstrates compliance with the standards of NSPS Subpart Da for duct burners.}* [Subpart Da, 40 CFR 60]

PROJECT PHASE-IN

12. Existing Unit 8 Simple Cycle Gas Turbines: Until commencement of the initial steam blows, the terms and conditions of Air Permit No. PSD-FL-286 shall apply to the two existing Unit 8 gas turbines (Emissions Unit Nos. 011 and 012), the two existing gas-fired fuel heaters (Emissions Unit 013) and the distillate oil storage tank (Emissions Unit 014). Thereafter, this PSD permit shall replace and supersede Air Permit No. PSD-FL-286. *{Permitting Note: Initial tests on gas and oil under normal conditions during simple cycle operation have already been conducted for the existing Unit 8 gas turbines.}* [Rule 62-4.070(3), F.A.C.]

EXCESS EMISSIONS

13. Operating Procedures: The Best Available Control Technology (BACT) determinations established by this permit rely on "good operating practices" to reduce emissions. Therefore, all operators and supervisors shall be properly trained to operate and maintain the gas turbines, HRSGs, and pollution control systems in accordance with the guidelines and procedures established by each manufacturer. The training shall include good operating practices as well as methods of minimizing excess emissions. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

14. Excess Emissions Prohibited: 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. All such preventable emissions shall be included in any compliance determinations based on CEMS data. [Rule 62-210.700(4), F.A.C.]

15. Alternate Visible Emissions Standard: Visible emissions due to startups, shutdowns, and malfunctions shall not exceed 10% opacity except for up to ten, 6-minute averaging periods during a calendar day, which shall not exceed 20% opacity. [Rule 62-212.400(BACT), F.A.C.]

16. Excess Emissions Allowed: As specified in this condition, excess emissions resulting from startup, shutdown, oil-to-gas fuel switches and documented malfunctions are allowed provided that operators employ the best operational practices to minimize the amount and duration of emissions during such incidents. A "documented malfunction" means a malfunction that is documented within one working day of detection by contacting the Compliance Authority by telephone, facsimile transmittal, or electronic mail. For each gas turbine/HRSG system, excess emissions resulting from startup, shutdown, or documented malfunctions shall not exceed two hours in any 24-hour period except for the following specific cases.

    a. For cold startup of the steam turbine system, excess emissions from any gas turbine/HRSG system shall not exceed six hours in any 24-hour period. Cold startup of the steam turbine system shall be completed within twelve hours. A cold "startup of the steam turbine system" is defined as startup of the 4-on-1 combined cycle system following a shutdown of the steam turbine lasting at least 48 hours. *{Permitting Note: During a cold startup of the steam turbine system, each gas turbine/HRSG system is sequentially brought on line at low load to gradually increase the temperature of the steam-electrical turbine and prevent thermal metal fatigue. Note that shutdowns and documented malfunctions are separately regulated in accordance with the requirements of this condition.}*

    b. For shutdown of the steam turbine system, excess emissions from any gas turbine/HRSG system shall not exceed three hours in any 24-hour period.

c. For cold startup of a gas turbine/HRSG system, excess emissions shall not exceed four hours in any 24-hour period. "Cold startup of a gas turbine/HRSG system" is defined as a startup after the pressure in the high-pressure (HP) steam drum falls below 450 psig for at least a one-hour period.

d. For oil-to-gas fuel switching in simple cycle operation, excess emissions shall not exceed 1 hour in any 24-hour period.

Ammonia injection shall begin as soon as operation of the gas turbine/HRSG system achieves the operating parameters specified by the manufacturer. As authorized by Rule 62-210.700(5), F.A.C., the above conditions allow excess emissions only for specifically defined periods of startup, shutdown, and documented malfunction of the gas turbines. [Design; Rules 62-212.400(BACT) and 62-210.700, F.A.C.]

17. Initial Steam Blows: Prior to completing the conversion from simple cycle to combined cycle operation, the permittee is authorized to operate each gas turbine at loads below 50% for the purpose of cleaning the HRSG piping system and piping connecting the HRSG to the steam turbine. Prior to conducting any steam blows, the permittee shall submit a proposed schedule. On the first day of conducting steam blows, the permittee shall notify the Compliance Authority that the process has begun. The permittee shall complete this process within 90 days of conducting the initial steam blow. For good cause, the permittee may request that the Compliance Authority extend the steam blow period. During the steam blows, the following conditions apply:

a. The permittee shall take all precautions to minimize the extent and duration of excess emissions.

b. Each gas turbine shall fire only natural gas and each CEMS shall be on line and functioning properly.

c. CO and NOx emissions may exceed the BACT limits specified in this permit; however, NOx emissions shall not exceed the NSPS Subpart GG limit of 110 ppmvd corrected to 15% oxygen based on a 24-hour block average. If the NSPS standard is exceeded, the permittee shall notify the Compliance Authority within one working day of the incident.

Within 30 days of completing the initial steam blows, the permittee shall submit a report to the Bureau of Air Regulation and the Compliance Authority summarizing the daily emissions resulting from each steam blow. *{Permitting Note: It is estimated that steam blows will occur intermittently over a 30-day period for each gas turbine/HRSG system followed by a similar 60-day period of intermittent steam blows for the common piping system serving the four interconnected combined cycle units. It is not expected that steam blows would occur every day during these periods. This condition only applies if simple cycle operation begins prior to combined cycle operation and NSPS compliance tests for simple cycle operation have been performed.}* [Application]

18. DLN Tuning: CEMS data collected during initial or other major DLN tuning sessions shall be excluded from the CEMS compliance demonstration provided the tuning session is performed in accordance with the manufacturer's specifications. A "major tuning session" would occur after completion of initial construction, a combustor change-out, a major repair or maintenance to a combustor, or other similar circumstances. Prior to performing any major tuning session, the permittee shall provide the Compliance Authority with an advance notice that details the activity and proposed tuning schedule. The notice may be by telephone, facsimile transmittal, or electronic mail. [Design; Rule 62-4.070(3), F.A.C.]

EMISSIONS PERFORMANCE TESTING

19. Test Methods: Any required tests shall be performed in accordance with the following reference methods.

Method	Description of Method and Comments
CTM-027	Procedure for Collection and Analysis of Ammonia in Stationary Source

	{Notes: This is an EPA conditional test method. The minimum detection limit shall be 1 ppm.}
7E	Determination of Nitrogen Oxide Emissions from Stationary Sources
9	Visual Determination of the Opacity of Emissions from Stationary Sources
10	Determination of Carbon Monoxide Emissions from Stationary Sources {Notes: The method shall be based on a continuous sampling train.}
18	Measurement of Gaseous Organic Compound Emissions by Gas Chromatography {Note: EPA Method 18 may be used (optional) concurrently with EPA Method 25A to deduct emissions of methane and ethane from the measured VOC emissions.}
20	Determination of Nitrogen Oxides, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines
25A	Determination of Volatile Organic Concentrations

Method CTM-027 is published on EPA's Technology Transfer Network Web Site at "http://www.epa.gov/ttn/emc/ctm.html". The other methods are described in Appendix A of 40 CFR 60, adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used unless prior written approval is received from the Department. [Rules 62-204.800, F.A.C.; 40 CFR 60, Appendix A]

20. Initial Compliance Determinations: Each gas turbine shall be stack tested to demonstrate initial compliance with the emission standards for CO, NOx, VOC, visible emissions, and ammonia slip. The tests shall be conducted within 60 days after achieving the maximum production rate at which the unit will be operated for each unit configuration (i.e., simple cycle and combined cycle operation), but not later than 180 days after the initial startup of each unit configuration. Each unit shall be tested when firing natural gas and distillate oil. CEMS data collected during the required Relative Accuracy Test Assessments (RATA) may be used to demonstrate compliance with the initial CO and NOx standards. With appropriate flow measurements (or fuel measurements and approved F-factors), CEMS data may be used to demonstrate compliance with the CO and NOx mass rate emissions standards. CO and NOx emissions recorded by the CEMS shall also be reported for each run during tests for visible emissions, VOC and ammonia slip. Initial CO and VOC emissions tests performed during simple cycle operation may be used to satisfy the initial test requirements for similar operation in combined cycle mode. The Department may require the permittee to conduct additional tests after major replacement or major repair of any air pollution control equipment, such as the SCR catalyst, DLN combustors, etc. [Rule 62-297.310(7)(a)1, F.A.C. and 40 CFR 60.8]

21. Continuous Compliance: The permittee shall demonstrate continuous compliance with the CO and NOx emissions standards based on data collected by the certified CEMS. Within 45 days of conducting any Relative Accuracy Test Assessments (RATA) on a CEMS, the permittee shall submit a report to the Compliance Authority summarizing results of the RATA. Compliance with the CO emission standards also serves as an indicator of efficient fuel combustion, which reduces emissions of particulate matter and volatile organic compounds. [Rule 62-212.400 (BACT), F.A.C.]

22. Annual Compliance Tests: During each federal fiscal year (October 1st to September 30th), each gas turbine shall be tested to demonstrate compliance with the emission standards for visible emissions. Annual testing to determine the ammonia slip shall be conducted while firing the primary fuel. NOx emissions recorded by the CEMS shall be reported for each ammonia slip test run. CO emissions recorded by the CEMS shall be reported for the visible emissions observation period. *{Permitting Note: After initial compliance with the VOC standards is demonstrated, annual compliance tests for VOC emissions are not required. Compliance with the continuously monitored CO standards shall indicate efficient combustion and low VOC emissions.}* [Rules 62-212.400 (BACT) and 62-297.310(7)(a)4, F.A.C.]

23. Additional Ammonia Slip Testing: If the tested ammonia slip rate for a gas turbine exceeds 5 ppmvd corrected to 15% oxygen when firing natural gas during the annual test, the permittee shall:

a. Begin testing and reporting the ammonia slip for each subsequent calendar quarter;

b. Before the ammonia slip exceeds 7 ppmvd corrected to 15% oxygen, take corrective actions that result in lowering the ammonia slip to less than 5 ppmvd corrected to 15% oxygen; and

c. Test and demonstrate that the ammonia slip is no more than 5 ppmvd corrected to 15% oxygen within 15 days after completing the corrective actions.

Corrective actions may include, but are not limited to, adding catalyst, replacing catalyst, or other SCR system maintenance or repair. After demonstrating that the ammonia slip level is no more than 5 ppmvd corrected to 15% oxygen, testing and reporting shall resume on an annual basis. [Rules 62-4.070(3) and 62-297.310(7)(b), F.A.C.]

CONTINUOUS MONITORING REQUIREMENTS

24. <u>CEM Systems</u>: The permittee shall install, calibrate, maintain, and operate continuous emission monitoring systems (CEMS) to measure and record the emissions of CO and NOx from the combined cycle gas turbine in a manner sufficient to demonstrate continuous compliance with the CEMS emission standards of this section. Each monitoring system shall be installed, calibrated, and properly functioning prior to the initial performance tests. Within one working day of discovering emissions in excess of a CO or NOx standard (and subject to the specified averaging period), the permittee shall notify the Compliance Authority.

    a. *CO Monitors.* The CO monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4 or 4A. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, and the Data Assessment Report of Section 7 shall be made each calendar quarter, and reported semiannually to the Compliance Authority. The RATA tests required for the CO monitor shall be performed using EPA Method 10 in Appendix A of 40 CFR 60 and shall be based on a continuous sampling train. The CO monitor span values shall be set appropriately considering the allowable methods of operation and corresponding emission standards.

    b. *NOx Monitors.* Each NOx monitor shall be certified, operated, and maintained in accordance with the requirements of 40 CFR 75. Record keeping and reporting shall be conducted pursuant to Subparts F and G in 40 CFR 75. The RATA tests required for the NO_X monitor shall be performed using EPA Method 20 or 7E in Appendix A of 40 CFR 60. In addition to the requirements of Appendix A of 40 CFR 75, the NOx monitor span values shall be set appropriately considering the allowable methods of operation and corresponding emission standards.

    c. *Diluent Monitors.* The oxygen (O_2) or carbon dioxide (CO_2) content of the flue gas shall be monitored at the location where CO and NOx are monitored to correct the measured emissions rates to 15% oxygen. If a CO_2 monitor is installed, the oxygen content of the flue gas shall be calculated using F-factors that are appropriate for the fuel fired. Each monitor shall comply with the performance and quality assurance requirements of 40 CFR 75.

    d. *1-Hour Block Averages.* Hourly average values shall begin at the top of each hour. Each hourly average value shall be computed using at least one data point in each fifteen-minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, an hourly value shall be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour). If less than two such data points are available, the hourly average value is not valid. An hour in which any oil is fired is attributed towards compliance with the permit standards for oil firing. The permittee shall use all valid measurements or data points collected during an hour to calculate the hourly average values. The CEMS shall be designed and operated to sample, analyze, and record data evenly spaced over an hour. If the CEMS measures concentration on a wet basis, the CEM system shall include provisions to determine the moisture content of the exhaust gas and an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Alternatively, the owner or operator may develop through manual stack test measurements a curve of moisture contents in the exhaust gas versus load for each allowable fuel, and use these typical values in an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Final results of the CEMS shall be expressed as ppmvd corrected to 15% oxygen. The CEMS shall be used to demonstrate compliance with the CEMS emission standards for CO and NOx as specified in this permit. For purposes of determining compliance with the CEMS emissions standards of this permit, missing (or excluded) data shall not be substituted. Upon request by the Department, the CEMS emission rates shall be corrected to ISO conditions to demonstrate compliance with the applicable standards of 40 CFR 60.332.

e. *3-hour Block Averages*: For oil firing during simple cycle operation, the 3-hour block average shall be calculated from three consecutive hourly average emission rate values. For purposes of determining compliance with the CEMS emission standards of this permit, missing (or excluded) data shall not be substituted. Instead, the 3-hour block average shall be determined using the remaining hourly data in the 3-hour block. [Rule 62-212.400(BACT), F.A.C.]

f. *24-hour Block Averages*: A 24-hour block shall begin at midnight of each operating day and shall be calculated from 24 consecutive hourly average emission rate values. If a unit operates less than 24 hours during the block, the 24-hour block average shall be the average of available valid hourly average emission rate values for the 24-hour block. For purposes of determining compliance with the 24-hour CEMS standards, missing (or excluded) data shall not be substituted. Instead, the 24-hour block average shall be determined using the remaining hourly data in the 24-hour block. *{Permitting Note: There may be more than one 24-hour compliance demonstration required for CO and NOx emissions depending on the use of alternate methods of operation}*. [Rule 62-212.400(BACT), F.A.C.]

g. *Data Exclusion.* Each CEMS shall monitor and record emissions during all operations including episodes of startup, shutdown, malfunction, fuel switches, DLN tuning, and steam blows. CEMS emissions data recorded during some of these episodes may be excluded from the corresponding CEMS compliance demonstration subject to the provisions of Condition Nos. 16 and 18 of this section. All periods of data excluded shall be consecutive for each such episode. The permittee shall minimize the duration of data excluded for such episodes to the extent practicable. Data recorded during such episodes shall not be excluded if the episode was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented. Best operational practices shall be used to minimize hourly emissions that occur during such episodes. Emissions of any quantity or duration that occur entirely or in part from poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented, shall be prohibited.

h. *Availability.* Monitor availability for the CEMS shall be 95% or greater in any calendar quarter. The quarterly permit excess emissions report shall be used to demonstrate monitor availability. In the event 95% availability is not achieved, the permittee shall provide the Department with a report identifying the problems in achieving 95% availability and a plan of corrective actions that will be taken to achieve 95% availability. The permittee shall implement the reported corrective actions within the next calendar quarter. Failure to take corrective actions or continued failure to achieve the minimum monitor availability shall be violations of this permit, except as otherwise authorized by the Department's Compliance Authority.

{Permitting Note: Compliance with these requirements ensure compliance with the other applicable CEM system requirements such as: NSPS Subparts Da and GG; Rule 62-297.520, F.A.C.; 40 CFR 60.7(a)(5) and 40 CFR 60.13; 40 CFR Part 51, Appendix P; 40 CFR 60, Appendix B - Performance Specifications; and 40

CFR 60, Appendix F - Quality Assurance Procedures.} [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

25. Water Injection Monitoring Requirements: In accordance with the manufacturer's specifications, the permittee shall install, calibrate, operate and maintain a monitoring system to continuously measure and record the water-to-fuel ratio when firing distillate oil. The permittee shall document the water-to-fuel ratio required to meet permitted emissions levels over the range of load conditions allowed by this permit. The NOx CEMS is used to demonstrate compliance with the NOx emissions standards. During NOx CEMS downtimes or malfunctions, the permittee shall monitor the water-to-fuel ratio and operate at a level that is consistent with the documented flow rate for the gas turbine load condition. *{Permitting Note: The water-to-fuel ratio at maximum load to achieve the NOx standards during simple cycle oil firing is approximately 1.1 or a water injection rate of approximately 101,000 pounds per hour. The actual water-to-fuel ratio will vary depending on operating conditions and load.}* [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

26. Ammonia Monitoring Requirements: In accordance with the manufacturer's specifications, the permittee shall install, calibrate, operate and maintain an ammonia flow meter to measure and record the ammonia injection rate to the SCR system. The permittee shall document the general range of ammonia flow rates required to meet permitted emissions levels over the range of load conditions allowed by this permit by comparing NOx emissions recorded by the CEM system with ammonia flow rates recorded using the ammonia flow meter. During NOx monitor downtimes or malfunctions, the permittee shall operate at the ammonia flow rate that is consistent with the documented flow rate for the combustion turbine load condition. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

RECORDS AND REPORTS

27. Monitoring of Capacity: The permittee shall monitor and record the operating rate of each gas turbine and HRSG duct burner system on a daily average basis, considering the number of hours of operation during each day (including the times of startup, shutdown and malfunction). Such monitoring shall be made using a monitoring component of the CEM system required above, or by monitoring daily rates of consumption and heat content of each allowable fuel in accordance with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

28. Monthly Operations Summary: By the fifth calendar day of each month, the permittee shall record the following for each fuel in a written or electronic log for each gas turbine for the previous month of operation: fuel consumption, hours of operation, hours of power augmentation, hours of peaking, hours of duct firing, and the updated 12-month rolling totals for each. Information recorded and stored as an electronic file shall be available for inspection and printing within at least three days of a request by the Department. The fuel consumption shall be monitored in accordance with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

29. Fuel Sulfur Records: The permittee shall demonstrate compliance with the fuel sulfur limits specified in this permit by maintaining the following records of the sulfur contents.

    a. Compliance with the fuel sulfur limit for natural gas shall be demonstrated by keeping reports obtained from the vendor indicating the average sulfur content of the natural gas being supplied from the pipeline for each month of operation. Methods for determining the sulfur content of the natural gas shall be ASTM methods D4084-82, D3246-81 or more recent versions.

    b. Compliance with the distillate oil sulfur limit shall be demonstrated by taking a sample, analyzing the sample for fuel sulfur, and reporting the results to each Compliance Authority before initial startup. Sampling the fuel oil sulfur content shall be conducted in accordance with ASTM D4057-88, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, and one of the following test methods for sulfur in petroleum products: ASTM D129-91, ASTM D1552-90, ASTM D2622-94, or

ASTM D4294-90. More recent versions of these methods may be used. For each subsequent fuel delivery, the permittee shall maintain a permanent file of the certified fuel sulfur analysis from the fuel vendor. At the request of a Compliance Authority, the permittee shall perform additional sampling and analysis for the fuel sulfur content.

The above methods shall be used to determine the fuel sulfur content in conjunction with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-4.160(15), F.A.C.]

30. <u>Malfunction Notification</u>: Within one working day of a malfunction that causes emissions in excess of a standard (subject to the specified averaging periods), the permittee shall notify the Compliance Authority. The notification shall include a preliminary report of: the nature, extent, and duration of the emissions; the probable cause of the emissions; and the actions taken to correct the problem. If requested by the Compliance Authority, the permittee shall submit written quarterly reports summarizing the malfunctions. [Rule 62-210.700, F.A.C.]

31. <u>Semiannual NSPS Excess Emissions Report</u>: In accordance with 40 CFR 60.7(d), the permittee shall submit a report to the Compliance Authority summarizing any emissions in excess of the NSPS standards within 30 days following the end of each calendar quarter. For purposes of reporting emissions in excess of NSPS Subpart GG, excess emissions from the gas turbine are defined as: any CEMS hourly average value exceeding the NSPS NOx emission standard identified in Appendix GG; and any daily period during which the sulfur content of the fuel being fired in the gas turbine exceeds the NSPS standard identified in Appendix GG. For purposes of reporting emissions in excess of NSPS Subpart Da, excess emissions from duct firing are defined as: NOx or PM emissions in excess of the NSPS standards except during periods of startup, shutdown, or malfunction; and SO_2 emissions in excess of the NSPS standards except during startup or shutdown. An example of the report is provided on Appendix XS. [40 CFR 60.7]

32. <u>Quarterly Permit Excess Emission Report</u>: Within 30 days following the end of each quarter, the permittee shall submit a report to the Compliance Authority summarizing periods of excess CO and NOx emissions. Such information shall also be summarized for simple/combined cycle startups, simple/combined cycle shutdowns, malfunctions, and major tuning sessions. In addition, the report shall summarize the CEMS systems monitor availability for the previous quarter. [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C.; and 40 CFR 60.7]

B. GAS-FIRED FUEL HEATERS (EU 013)

This section of the permit addresses the following new emissions units.

EU No.	Emission Unit Description
013	Four gas-fired fuel heaters with a maximum heat input of 24 MMBtu per hour

NSPS SUBPART DC APPLICABILITY

{Permitting Note: FPL requested a determination from the Department on the applicability of NSPS Subpart Dc to the gas-fired fuel heaters. The Department agreed with FPL that it did not believe that Subpart Dc should apply to these units, but referred the request to EPA Region 4 for interpretation of the federal standards. In a letter dated February 5, 2003, EPA Region 4 concurred that Subpart Dc did not apply to the gas-fired fuel heaters.}

EQUIPMENT SPECIFICATIONS

1. Equipment: The permittee is authorized to install, operate, and maintain four fuel heaters fired exclusively with natural gas at a maximum heat input rate of 24 MMBtu per hour. The fuel heaters will be designed to preheat the natural gas during simple cycle operation and during startup to combined cycle operation. For full combined cycle operation, feedwater heat exchangers will preheat the natural gas. *{Permitting Note: In accordance with Air Permit No. PSD-FL-286, construction of two gas-fired fuel heaters has been completed.}* [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

EMISSIONS AND PERFORMANCE REQUIREMENTS

2. Hours of Operation: The hours of operation for the gas-fired fuel heaters are not restricted (8760 hours per year). [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

3. Good Combustion: If visible emissions are greater than 5% opacity, the permittee shall investigate the cause, take appropriate corrective actions, and document the incident. This condition does not impose any initial or periodic testing. [Rules 62-4.070(3) and 62-210.700(4), F.A.C.; 40 CFR 60, Appendix A]

NOTIFICATION, REPORTING AND RECORDS

4. Fuel Records: The permittee shall maintain records of the amount of natural gas fired in the fuel heaters. These records shall be used to prepare the required annual operating reports. [Rule 62-210.370(3), F.A.C.]

C. COOLING TOWER (EU 020)

This section of the permit addresses the following new emissions unit.

ID	Emission Unit Description
020	18-cell mechanical draft cooling tower

EQUIPMENT

1. Cooling Tower: The permittee is authorized to install one new 18-cell mechanical draft cooling tower with the following design characteristics: a circulating water flow rate of 310,000 gpm; design hot/cold water temperatures of 104° F/90° F; a design air flow rate of 1,386,055 per cell; a liquid-to-gas air flow ratio of 1.4; and drift eliminators with a drift rate of no more than 0.001 percent. The permittee shall submit the final design details within 60 days of selecting the vendor. [Application; Design]

EMISSIONS AND PERFORMANCE REQUIREMENTS

2. Drift Rate: Within 60 days of commencing operation, the permittee shall submit certify that the cooling tower was constructed to achieve the specified drift rate of no more than 0.001 percent of the circulating water flow rate. *{Permitting Note: This work practice standard is established as BACT for PM/PM10 emissions from the cooling tower. Based on this design criteria, potential emissions are expected to be less than 34 tons of PM per year and less than 10 tons of PM10 per year. Actual emissions are expected be less than half these rates.}*. [Rule 62-212.400(BACT), F.A.C.]

D. DISTILLATE OIL STORAGE TANK (EU 014)

This section of the permit addresses the following emissions unit.

ID	Emission Unit Description
014	Two distillate oil storage tanks for Unit 8 gas turbines (2.1 million gallons each)

NSPS APPLICABILITY

1. NSPS Subpart Kb Applicability: The distillate oil tanks are subject to Subpart Kb, which applies to any storage tank with a capacity greater than or equal to 10,300 gallons (40 cubic meters) that is used to store volatile organic liquids for which construction, reconstruction, or modification is commenced after July 23, 1984. Tanks with a capacity greater than or equal to 40,000 gallons (151 cubic meters) storing a liquid with a maximum true vapor pressure less than 3.5 kPa are exempt from the General Provisions (40 CFR 60, Subpart A) and from the provisions of NSPS Subpart Kb, except for the record keeping requirements specified below. [40 CFR 60.110b(a) and (c); Rule 62-204.800(7)(b), F.A.C.]

EQUIPMENT SPECIFICATIONS

2. Equipment: The permittee is authorized to install, operate, and maintain one, 2.1 million gallon distillate oil storage tank designed to provide low sulfur distillate oil to the Unit 8 gas turbines. *{Permitting Note: There is one existing 2.1 million gallon distillate oil storage tank.}* [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

EMISSIONS AND PERFORMANCE REQUIREMENTS

3. Hours of Operation: The hours of operation are not restricted (8760 hours per year). [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

NOTIFICATION, REPORTING AND RECORDS

4. Oil Tank Records: The permittee shall keep readily accessible records showing the dimension of each storage vessel and an analysis showing the capacity of each storage tank. Records shall be retained for the life of the facility. The permittee shall also keep records sufficient to determine the annual throughput of distillate oil for each storage tank for use in the Annual Operating Report. [Rule 62-204.800(7)(b)16, F.A.C.; 40 CFR 60.116b(a) and (b)]

{Permitting Note: The new distillate oil storage tank is an additional tank that can serve Unit 8. An existing 50,000-barrel distillate oil storage tank was constructed as part of Units 3 and 4. The existing tank was identified for use in Permit No. PSD-FL-268 issued for simple cycle Units 8A and 8B. When operational, Unit 8 will utilize both the existing and new distillate oil storage tanks.}

SECTION IV. APPENDICES

CONTENTS

NSPS SUBPART A, IDENTIFICATION OF GENERAL PROVISIONS

Emissions units subject to a New Source Performance Standard of 40 CFR 60 are also subject to the applicable requirements of Subpart A, the General Provisions, including:

§ 60.1 Applicability.

§ 60.2 Definitions.

§ 60.3 Units and abbreviations.

§ 60.4 Address.

§ 60.5 Determination of construction or modification.

§ 60.6 Review of plans.

§ 60.7 Notification and Record Keeping.

§ 60.8 Performance Tests.

§ 60.9 Availability of information.

§ 60.10 State Authority.

§ 60.11 Compliance with Standards and Maintenance Requirements.

§ 60.12 Circumvention.

§ 60.13 Monitoring Requirements.

§ 60.14 Modification.

§ 60.15 Reconstruction.

§ 60.16 Priority List.

§ 60.17 Incorporations by Reference.

§ 60.18 General Control Device Requirements.

§ 60.19 General Notification and Reporting Requirements.

Individual subparts may exempt specific equipment or processes from some or all of these requirements. The general provisions may be provided in full upon request.

FINAL BACT DETERMINATIONS AND EMISSIONS STANDARDS

OVERVIEW

The project added an 1150 MW "4-on-1" combined cycle gas turbine system to the existing FPL Martin Power Plant. PSD-significant emissions increases required determinations of the Best Available Control Technology (BACT) for carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM_{10}), sulfuric acid mist (SAM), and sulfur dioxide (SO_2), and volatile organic compounds (VOC).

BACT CONTROL TECHNOLOGIES

The Department reviewed available control technologies for each pollutant resulting in a PSD-significant increase. The Department's technical review and rationale for the BACT determinations are presented in the "Technical Evaluation and Preliminary Determination" as revised prior to the siting hearing. The following summarizes the control technologies upon which the Department's final BACT determinations are based.

BACT for CO and VOC Emissions

Good Combustion and Operating Practices: BACT for CO and VOC emissions is the efficient combustion of fuels at high temperatures associated with good combustion design and operating practices. General Electric's dual-fuel combustors have demonstrated very low CO and VOC emissions while simultaneously reducing NOx emissions for gas and oil firing.

BACT for NOx Emissions

DLN Combustion: When firing natural gas under simple cycle mode, BACT for NOx emissions is the operation of General Electric's dry low-NOx (DLN) combustion system. The efficient fuel combustion and thorough mixing of the gas stream reduces hot and cold spots surrounding the combustion zone. The full lean premix combustion results in NOx emissions less than 9 ppmvd when firing natural gas. The Speedtronic™ control system continuously monitors performance parameters and adjusts for efficient operation. The control system also provides for quick automated startups, lean pre-mix combustion performance, and controlled shutdowns.

Wet Injection: When firing distillate oil under simple cycle mode, BACT for NOx emissions is the operation of General Electric's dual-fuel combustor with wet injection designed to reduce the flame temperature and lower NOx emissions.

SCR: When firing natural gas or distillate oil in combined cycle mode, BACT for NOx emissions is the operation of the selective catalytic reduction (SCR) system in conjunction with DLN combustion and wet injection. Ammonia injected into the exhaust gas stream combines with NOx in a reduction action across a catalyst bed to form nitrogen and water. The catalyst bed is located after the HRSG, which reduces exhaust temperatures to the appropriate operating range of the catalyst material. The SCR system will achieve about a 70% reduction with an initial ammonia slip of no more than 5 ppmvd.

BACT for PM, SAM, and SO_2 Emissions

Fuel Specifications: BACT for PM, SAM, and SO_2 emissions is the use of natural gas as the primary fuel (≤ 2.0 grains of sulfur per 100 standard cubic feet of natural gas) and restricted use of very low sulfur distillate oil (≤ 0.05% sulfur by weight). These fuels are readily combustible and contain little ash, sulfur, or other contaminants.

BACT STANDARDS

The following summarizes the final Best Available Control Technology determinations for this project in accordance with Rule 62-212.400(BACT), F.A.C.

Gas-Fired Fuel Heaters: BACT for emissions of CO, NOx, PM/PM_{10}, SAM, SO_2, and VOC from the gas-fired fuel heaters is the efficient combustion of natural gas and the following visible emissions criteria, "If visible emissions are greater than 5% opacity, the permittee shall investigate the cause, take appropriate corrective actions, and document the incident. This condition does not impose any initial or periodic testing." This condition is similar to that for the previously permitted gas-fired fuel heaters under Permit No. PSD-FL-286.

Cooling Tower: BACT for emissions of PM/PM_{10} from the cooling tower is a design drift rate of no more than 0.001 percent of the circulating water flow rate.

Gas Turbines/HRSG Systems

Pollutant	Fuel	Method of Operation	Stack Test, 3-Run Average		CEMS Block Average
			ppmvd @ 15% O2	lb/hour	ppmvd @ 15% O2
CO[a]	Oil	Simple or Combined Cycle	14.4	64.7	15.0, 24-hr
	Gas	Simple Cycle	7.4	27.5	8.0, 24-hr
		Simple Cycle w/PA	12.0	45.0	12.0, 24-hr
		Combined Cycle, Normal	7.4	27.5	10.0, 24-hr
		Combined Cycle, All Modes	NA	NA	
NOx[b]	Oil	Simple Cycle	42.0	319.2	42.0, 3-hr
		Combined Cycle w/SCR	10.0	76.0	10.0, 24-hr
	Gas	Simple Cycle	9.0	58.7	9.0, 24-hr
		Simple Cycle w/PA	12.0	76.2	12.0, 24-hr
		Simple Cycle w/Peaking	15.0	95.3	15.0, 24-hr
		Combined Cycle w/SCR, Normal	2.5	16.3	2.5, 24-hr
		Combined Cycle w/SCR and DB	2.5	23.6	
		Combined Cycle w/SCR, All Modes	NA	NA	
PM/PM10[c]	Oil/Gas	Simple or Combined Cycle	Fuel Specifications		
		Simple or Combined Cycle	Visible emissions shall not exceed 10% opacity for each 6-minute block average.		
SAM/SO2[d]	Oil/Gas	Simple or Combined Cycle	Fuel Specifications		
VOC[e]	Oil	Simple or Combined Cycle	2.5	6.0	NA
	Gas	Simple or Normal Combined Cycle	1.3	2.8	NA
		Combined Cycle, w/DB and/or PA	4.0	10.5	NA
Ammonia[f]	Oil/Gas	Combined Cycle w/SCR	5.0	NA	NA

a. Compliance with the CO standards shall be demonstrated based on data collected by the required CEMS. Compliance may also be determined by EPA Method 10. Compliance with the 24-hour CO CEMS standards shall be determined separately for each method of operation based on the hours of operation for each method. *{Permitting Note: A 24-hour compliance average may be based on as little as 1-hour of CEMS data or as much as 24-hours of CEMS data.}*

b. Compliance with the NOx standards shall be demonstrated based on data collected by the required CEMS. Compliance may also be determined by EPA Method 7E or 20. NOx mass emission rates are defined as oxides of nitrogen expressed as NO_2. Compliance with the 24-hour NOx CEMS standards during simple cycle operation shall be determined separately for each method of operation based on the hours of operation for each method. *{Permitting Note: A 24-hour compliance average may be based on as little as 1-hour of CEMS data or as much as 24-hours of CEMS data.}*

c. The fuel specifications established above combined with the efficient combustion design and operation of each gas turbine represents the Best Available Control Technology (BACT) determination for PM/PM10 emissions. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion. Compliance with the fuel specifications shall be demonstrated by keeping records of the fuel sulfur content. Compliance with the visible emissions standard shall be demonstrated by conducting tests in accordance with EPA Method 9. *{Permitting Note: PM10 emissions for gas firing are estimated at 9 lb/hour for simple cycle operation, 11 lb/hour for combined cycle operation, and 17 lb/hour for combined cycle operation with duct burning. PM10* *emissions for oil firing are estimated at 17 lb/hour for simple cycle operation and 37 lb/hour for combined cycle operation.}*

d. The fuel sulfur specifications effectively limit the potential emissions of SAM and SO_2 from the gas turbines and represent the Best Available Control Technology (BACT) determination for these pollutants. *{Permitting Note: SO_2 emissions for gas firing are estimated at 9.8 lb/hour for simple and combined cycle operation and 12.8 lb/hour for combined cycle operation with duct burning. SO_2 emissions for oil firing are estimated at 99 lb/hour for simple and combined cycle operation. SAM emissions are estimated to be less than 10% of the SO_2 emissions.}*

e. Compliance with the VOC standards shall be demonstrated by conducting tests in accordance with EPA Method 25A. Optionally, EPA Method 18 may also be performed to deduct emissions of methane and ethane. The emission standards are based on VOC measured as methane.

f. Subject to the following testing requirements, each SCR system shall be designed and operated for an initial ammonia slip target of no more than 5.0 ppmvd corrected to 15% oxygen based on the average of three test runs. Compliance with the ammonia slip standard shall be demonstrated by conducting tests in accordance with EPA Method CTC-027.

Additional Ammonia Slip Testing: If the tested ammonia slip rate for a gas turbine exceeds 5.0 ppmvd corrected to 15% oxygen when firing natural gas during the annual test, the permittee shall:

a. Begin testing and reporting the ammonia slip for each subsequent calendar quarter;

b. Before the ammonia slip exceeds 7 ppmvd corrected to 15% oxygen, take corrective actions that result in lowering the ammonia slip to less than 5 ppmvd corrected to 15% oxygen; and

c. Test and demonstrate that the ammonia slip is less than 5 ppmvd corrected to 15% oxygen within 15 days after completing the corrective actions.

Corrective actions may include, but are not limited to, adding catalyst, replacing catalyst, or other SCR system maintenance or repair. After demonstrating that the ammonia slip level is less than 5 ppmvd corrected to 15% oxygen, testing and reporting shall resume on an annual basis. [Rules 62-4.070(3) and 62-297.310(7)(b), F.A.C.]

{Permitting Notes: "DB" means duct burning. "PA" means power augmentation. "SCR" means selective catalytic reduction. "NA" means not applicable. The mass emission rate standards are based on a turbine inlet condition of 59° F and may be adjusted to actual test conditions in accordance with the performance curves and/or equations on file with the Department. Initial compliance tests under normal conditions for gas and oil firing have already been conducted for the existing Unit 8 gas turbines.}

FINAL BACT DETERMINATIONS

As summarized above, the Department determines that the standards specified in this permit represent the Best Available Control Technology (BACT) for emissions of CO, NOx, PM, SAM, SO_2, and VOC. The Department's technical review and rationale for the BACT determinations are presented in Technical Evaluation and Preliminary Determination issued concurrently with the draft permit.

Determination By:

Jeffrey J. Koerner

Jeff Koerner, P.E., Project Engineer
New Source Review Section

Recommended By:

Trina L Vielhauer

Trina Vielhauer, Chief
Bureau of Air Regulation

Approved By:

Howard L Rhodes

Howard L. Rhodes, Director
Division of Air Resources Management

CITATION FORMAT AND DEFINITIONS

The following examples illustrate the format used in the permit to identify applicable permitting actions and regulations.

REFERENCES TO PREVIOUS PERMITTING ACTIONS

Old Permit Numbers

Example: Permit No. AC50-123456 or Air Permit No. AO50-123456

Where: "AC" identifies the permit as an Air Construction Permit
"AO" identifies the permit as an Air Operation Permit
"123456" identifies the specific permit project number

New Permit Numbers

Example: Permit Nos. 099-2222-001-AC, 099-2222-001-AF, 099-2222-001-AO, or 099-2222-001-AV

Where: "099" represents the specific county ID number in which the project is located
"2222" represents the specific facility ID number
"001"identifies the specific permit project
"AC" identifies the permit as an air construction permit
"AF" identifies the permit as a minor federally enforceable state operation permit
"AO" identifies the permit as a minor source air operation permit
"AV" identifies the permit as a Title V Major Source Air Operation Permit

PSD Permit Numbers

Example: Permit No. PSD-FL-317

Where: "PSD" means issued pursuant to the Prevention of Significant Deterioration of Air Quality
"FL" means that the permit was issued by the State of Florida
"317" identifies the specific permit project

RULE CITATION FORMATS

Florida Administrative Code (F.A.C.)

Example: [Rule 62-213.205, F.A.C.]

Means: Title 62, Chapter 213, Rule 205 of the Florida Administrative Code

Code of Federal Regulations (CFR)

Example: [40 CFR 60.7]

Means: Title 40, Part 60, Section 7

DEFINITIONS [RULE 62-210.200, F.A.C.]

(119) Excess Emissions - Emissions of pollutants in excess of those allowed by any applicable air pollution rule of the Department, or by a permit issued pursuant to any such rule or Chapter 62-4, F.A.C. The term applies only to conditions which occur during startup, shutdown, soot blowing, load changing or malfunction.

(179) Malfunction - Any unavoidable mechanical and/or electrical failure of air pollution control equipment or process equipment or of a process resulting in operation in an abnormal or unusual manner.

(258) Shutdown - The cessation of the operation of an emissions unit for any purpose.

(275) Startup - The commencement of operation of any emissions unit which has shut down or ceased operation for a period of time sufficient to cause temperature, pressure, chemical or pollution control device imbalances, which result in excess emissions.

NSPS SUBPART Da REQUIREMENTS FOR DUCT BURNERS

The HRSG duct burners are part of the Unit 8 gas turbine/HRSG systems, which are regulated as Emissions Units 011, 012, 017, and 018.

§ 60.40a Applicability and Designation of Affected Facility.

The HRSG duct burner systems are part of an electric utility steam generating unit that is capable of combusting more than 250 MMBtu per hour heat input of fossil fuel for which construction or modification is commenced after September 18, 1978. Therefore, the requirements of NSPS Subpart Da apply to the HRSG duct burners systems. Only emissions resulting from combustion of fuels in the steam generating unit are subject to this subpart. Emissions from the gas turbines are subject to the requirements of NSPS Subpart GG. The HRSG duct burner systems are also subject to the applicable requirements of the General Provisions in Subpart A.

§ 60.41a Definitions.

"Duct burner" means a device that combusts fuel and that is placed in the exhaust duct from another source, such as a stationary gas turbine, internal combustion engine, kiln, etc., to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a heat recovery steam generating unit.

"Electric utility combined cycle gas turbine" means any combined cycle gas turbine used for electric generation that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW electrical output to any utility power distribution system for sale. Any steam distribution system that is constructed for the purpose of providing steam to a steam electric generator that would produce electrical power for sale is also considered in determining the electrical energy output capacity of the affected facility.

"Electric utility steam generating unit" means any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW electrical output to any utility power distribution system for sale. Any steam supplied to a steam distribution system for the purpose of providing steam to a steam-electric generator that would produce electrical energy for sale is also considered in determining the electrical energy output capacity of the affected facility.

"Fossil fuel" means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat.

"Gross output" means the gross useful work performed by the steam generated. For units generating only electricity, the gross useful work performed is the gross electrical output from the turbine/generator set. For cogeneration units, the gross useful work performed is the gross electrical output plus one half the useful thermal output (i.e., steam delivered to an industrial process).

"Potential electrical output capacity" is defined as 33 percent of the maximum design heat input capacity of the steam generating unit (e.g., a steam generating unit with a 100–MW (340 million Btu/hr) fossil-fuel heat input capacity would have a 33–MW potential electrical output capacity). For electric utility combined cycle gas turbines the potential electrical output capacity is determined on the basis of the fossil-fuel firing capacity of the steam generator exclusive of the heat input and electrical power contribution by the gas turbine.

"Steam generating unit" means any furnace, boiler, or other device used for combusting fuel for the purpose of producing steam (including fossil-fuel-fired steam generators associated with combined cycle gas turbines; nuclear steam generators are not included).

§ 60.42a Standard for Particulate Matter.

§ 60.42a(a)(1) establishes a particulate matter limit of 0.03 lb/MMBtu heat input from the combustion of gaseous fuel and an opacity limit of 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity. Natural gas is the primary fuel for the gas turbines with very low sulfur distillate oil as a backup fuel. Natural gas is the exclusive fuel for the duct burner systems. As the worst case, the maximum PM/PM_{10} emissions are expected to be less than 0.01 lb/MMBtu heat input from firing distillate oil in the gas turbine and natural gas in the duct burners. The stack opacity is limited by permit to 10% or less. Therefore, the Department determines that compliance with the conditions of the PSD permit ensure compliance with the requirements of NSPS Subpart Da.

§ 60.43a Standard for Sulfur Dioxide.

In accordance with § 60.43a(b)(2), sulfur dioxide emissions shall not exceed 0.20 lb/MMBtu heat input from the combustion of gaseous fuel for uncontrolled sources. Natural gas is the primary fuel for the gas turbines with very low sulfur distillate oil (≤ 0.05% sulfur by weight) as a backup fuel. Natural gas is the exclusive fuel for the duct burner systems. As the worst case, the maximum SO_2 emissions are expected to be less than 0.05 lb/MMBtu heat input from firing distillate oil in the gas turbine and natural gas in the duct burners. Therefore, the Department determines that compliance with the conditions of the PSD permit ensure compliance with the requirements of NSPS Subpart Da.

§ 60.44a Standard for Nitrogen Oxides.

In accordance with § 60.44a(d)(1), nitrogen oxides (expressed as NO_2) from a gas turbine/HRSG system with duct burners shall not exceed 1.6 pounds per megawatt-hour gross energy output. The permittee shall demonstrate compliance with this requirement based upon an initial test. Thereafter, compliance with the BACT standards of the PSD permit will demonstrate compliance with the NSPS Subpart Da limit. After investigation, if there is good reason to believe that this standard is being violated, the Department may require subsequent compliance testing in accordance with Rule 62-297.310(7)(b), F.A.C.

§ 60.46a Compliance Provisions.

The HRSG duct burner systems are restricted to the exclusive firing of natural gas. The maximum expected emissions of particulate matter and sulfur dioxide are much lower than the limits established by this subpart. Therefore, no testing is required to demonstrate compliance with the standards specified in § 60.42a (particulate matter) and § 60.43a (sulfur dioxide). Compliance with the opacity limit of 10% established in the PSD permit ensures compliance with the NSPS opacity standard.

In accordance with § 60.46a(k)(1), compliance with the nitrogen oxides (NOx) standard specified in § 60.44a(d)(1) for duct burners used in combined cycle systems shall be determined as follows:

$$E = [(Csg \times Qsg) - (Cte \times Qte)]/(Osg \times h) \qquad \text{(Equation 1)}$$

Where:

E	=	Emission rate of NOx from the duct burner, ng/J (lb/Mwh) gross output
Csg	=	Average hourly concentration of NOx exiting the steam generating unit, ng/ dscm (lb/dscf)
Cte	=	Average hourly concentration of NOx in the turbine exhaust upstream from duct burner, ng/dscm (lb/dscf)
Qsg	=	Average hourly volumetric flow rate of exhaust gas from steam generating unit, dscm/hr (dscf/hr)
Qte	=	Average hourly volumetric flow rate of exhaust gas from combustion turbine, dscm/hr (dscf/hr)
Osg	=	Average hourly gross energy output from steam generating unit, J (Mwh)
h	=	Average hourly fraction of the total heat input to the steam generating unit de-rived from the combustion of fuel in the affected duct burner

Method 7E of Appendix A of Part 60 shall be used to determine the NOx concentrations (Csg and Cte). Method 2, 2F or 2G of Appendix A of Part 60, as appropriate, shall be used to determine the volumetric flow rates (Qsg and Qte) of the exhaust gases. The volumetric flow rate measurements shall be taken at the same time as the concentration measurements.

The owner or operator shall develop, demonstrate, and provide information satisfactory to the Administrator to determine the average hourly gross energy output from the steam generating unit, and the average hourly percentage of the total heat input to the steam generating unit derived from the combustion of fuel in the affected duct burner.

Compliance with the emissions limits under § 60.44a(d)(1) is determined by the three-run average (nominal 1- hour runs) for the initial performance tests. Thereafter, compliance with the NOx limits established in the PSD permit shall demonstrate compliance with NOx limit specified in NSPS Subpart Da.

In accordance with § 60.46a(k)(3), when an affected duct burner steam generating unit utilizes a common steam turbine with one or more affected duct burner steam generating units, the owner or operator shall either:

Determine compliance with the applicable NOx emissions limits by measuring the emissions combined with the emissions from the other units utilizing the common steam turbine; or

Develop, demonstrate, and provide information satisfactory to the Administrator on methods for apportioning the combined gross energy output from the steam turbine for each of the affected duct burners. The Administrator may approve such demonstrated substitute methods for apportioning the combined gross energy output measured at the steam turbine whenever the demonstration ensures accurate estimation of emissions regulated under Part 60.

§ 60.47a Emission Monitoring.

In accordance with § 60.47a(o), the owner or operator of a duct burner, as described in § 60.41a, which is subject to the NOx standards of § 60.44a(a)(1) or (d)(1) is not required to install or operate a continuous emissions monitoring system to measure NOX emissions; a wattmeter to measure gross electrical output; meters to measure steam flow, temperature, and pressure; and a continuous flow monitoring system to measure the flow of exhaust gases discharged to the atmosphere.

§ 60.48a Compliance Determination Procedures and Methods.

In accordance with § 60.48a (d)(1), EPA Method 19 shall be used to determine the NOx emission rate when demonstrating compliance with the NOx standard specified in § 60.44a. In accordance with § 60.48a(f), electric utility combined cycle gas turbines are performance tested for particulate matter, sulfur dioxide, and nitrogen oxides using the procedures of Method 19. The sulfur dioxide and nitrogen oxides emission rates from the gas turbine used in Method 19 calculations are determined when the gas turbine is performance tested under subpart GG. The potential uncontrolled particulate matter emission rate from a gas turbine is defined as 17 ng/J (0.04 lb/million Btu) heat input.

§ 60.49a Reporting requirements.

Compliance with reporting requirements of the PSD permit ensure compliance with the requirements of NSPS Subpart Da.

GENERAL CONDITIONS

The permittee shall comply with the following general conditions from Rule 62-4.160, F.A.C.

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.

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, exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.

3. As provided in Subsections 403.087(6) and 403.722(5), Florida Statutes, the issuance of this permit does not convey and 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.

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.

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.

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.

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.

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.

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.

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.
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.
12. This permit or a copy thereof shall be kept at the work site of the permitted activity.
13. This permit also constitutes:
    a. Determination of Best Available Control Technology (X);
    b. Determination of Prevention of Significant Deterioration (X); and
    c. Compliance with New Source Performance Standards (X).
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.
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.

NSPS Subpart GG Requirements for Gas Turbines

The Unit 8 gas turbines are regulated as Emissions Units 011, 012, 017, and 018.

§ 60.330 Applicability and Designation of Affected Facility.

Each Unit 8 gas turbine has a heat input at peak load equal to or greater than 10 MMBtu per hour (LHV) and will commence construction after October 3, 1977. Therefore, the gas turbines are subject to NSPS Subpart GG.

§ 60.331 Definitions.

The following applicable terms are defined by this subpart:

(a) Stationary gas turbine means any simple cycle gas turbine, regenerative cycle gas turbine or any gas turbine portion of a combined cycle steam/electric generating system that is not self propelled. It may, however, be mounted on a vehicle for portability.

(b) Simple cycle gas turbine means any stationary gas turbine which does not recover heat from the gas turbine exhaust gases to preheat the inlet combustion air to the gas turbine, or which does not recover heat from the gas turbine exhaust gases to heat water or generate steam.

(d) Combined cycle gas turbine means any stationary gas turbine which recovers heat from the gas turbine exhaust gases to heat water or generate steam.

(g) ISO standard day conditions mean 288 degrees Kelvin, 60 percent relative humidity and 101.3 kilopascals pressure.

(h) Efficiency means the gas turbine manufacturer's rated heat rate at peak load in terms of heat input per unit of power output based on the lower heating value of the fuel.

(i) Peak load means 100 percent of the manufacturer's design capacity of the gas turbine at ISO standard day conditions.

(j) Base load means the load level at which a gas turbine is normally operated.

(q) Electric utility stationary gas turbine means any stationary gas turbine constructed for the purpose of supplying more than one-third of its potential electric output capacity to any utility power distribution system for sale.

§ 60.332 Standard for Nitrogen Oxides.

In accordance with § 60.332(a)(1) and (b), emissions of nitrogen oxides (NOx) from electric utility stationary gas turbines with a heat input at peak load greater than 100 MMBtu Btu per hour (LHV) shall not exceed the following standard.

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

Where:

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

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

F = NOx emission allowance for fuel-bound nitrogen as de-fined in paragraph (a)(3) of this section.

§ 60.332(a)(3) defines an allowable NOx contribution based on the fuel bound nitrogen content, F. However, natural gas and distillate oil contain negligible concentrations of fuel bound nitrogen. Therefore, "F" shall be assumed to be 0. Based on the manufacturer's data and compressor inlet conditions of 59° F and 60% relative humidity, the heat rate for gas firing is 9250 Btu/KW-h at peak load and for oil firing is 9960 Btu/KW-h at peak load. This results in "Y" values of 9.8 for gas firing and 10.5 for oil firing. The equivalent NSPS NOx emission standards are 110/103 ppmvd at 15% oxygen for gas/oil firing. Compliance with the NOx standards of the PSD permit ensure compliance with the applicable NSPS standards. The permittee shall make the correction when required by the Department or Administrator.

§ 60.333 Standard for Sulfur Dioxide

In accordance with § 60.333(b), fuel fired in the gas turbines shall contain no more than 0.8% sulfur by weight. The conditions of the PSD permit limit allowable fuels to natural gas (≤ 2.0 grains of sulfur per 100 standard cubic feet of natural gas) and distillate oil ($\leq$ 0.05% sulfur by weight). These conditions ensure compliance with the NSPS standard for sulfur dioxide.

§ 60.334 Monitoring of Operations.

The PSD permit requires keeping monthly records of the fuel sulfur content of natural gas. For distillate oil, the PSD permit requires initial fuel sulfur sampling and then keeping records of the fuel sulfur content based on vendor information "as supplied" for each subsequent shipment. Appropriate test methods are also specified in the PSD permit. These requirements constitute a custom fuel monitoring schedule that ensures compliance with the NSPS requirements for monitoring the nitrogen and sulfur contents of the fuels. The requirement to monitor the nitrogen contents of these fuels is waived due to negligible concentrations and the PSD conditions that require compliance with the NOx standards to be demonstrated by CEMS. The CEMS shall be installed, operated, and maintained in accordance with the requirements of the PSD permit.

For the purpose of reports required under § 60.7(c), periods of excess emissions that shall be reported are: any 1-hour period of NOx emissions greater than the NSPS standard; and any daily period during which the sulfur content of the fuel being fired in the gas turbine exceeds 0.8% sulfur by weight (for sulfur dioxide emissions). The permittee shall submit a semiannual report of emissions in excess of the NSPS standards.

§ 60.335 Test Methods and Procedures.

In accordance with § 60.335(c), compliance with the nitrogen oxides standards in § 60.332 shall be determined by computing the nitrogen oxides emission rate (NOx) for each run using the following equation:

$$NOx = (NOxo)\,(Pr/Po)^{0.5}\, e^{19(Ho-0.00633)}\,(288°K/Ta)^{1.53}$$

Where:

NOx	=	Emission rate of NOx at 15 percent O_2 and ISO standard ambient conditions, volume percent
NOxo	=	Observed NOx concentration, ppm by volume
Pr	=	Reference combustor inlet absolute pressure at 101.3 kilopascals ambient pressure, mm Hg
Po	=	Observed combustor inlet absolute pressure at test, mm Hg
Ho	=	Observed humidity of ambient air, g H_2O/g air
e	=	Transcendental constant, 2.718
Ta	=	Ambient temperature, °K

Tests for nitrogen oxides emissions shall be conducted in accordance with the schedule and methods specified in the PSD permit. The permittee is allowed to conduct initial performance tests at a single load because a NOx monitor shall be used to demonstrate compliance with the specified NOx limits. The permittee is allowed to make the initial compliance demonstration for NOx emissions using certified CEMS data, provided that compliance is based on a minimum of three test runs representing a total of at least three hours of data, and that the CEMS be calibrated in accordance with the procedure in section 6.2.3 of Method 20 following each run. Alternatively, initial compliance may be demonstrated using data collected during the initial relative accuracy test audit (RATA) performed on the NOx monitor. The permittee is not required to have the NOx monitor continuously correct NOx emissions concentrations to ISO conditions. However, the permittee shall make the correction when required by the Department or Administrator.

The permittee shall use the methods specified in the PSD permit to demonstrate compliance with the fuel sulfur specification, which will ensure compliance with the NSPS standard.

STANDARD CONDITIONS

Unless otherwise specified in the permit, the following conditions apply to all emissions units and activities at this facility.

EMISSIONS AND CONTROLS

1. 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 permittee shall notify each Compliance Authority as soon as possible, but at least within one working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; 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 or the regulations. [Rule 62-4.130, F.A.C.]

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

3. Excess Emissions Allowed: Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration. [Rule 62-210.700(1), F.A.C.]

4. Excess Emissions Prohibited: 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. [Rule 62-210.700(4), F.A.C.]

5. Excess Emissions - Notification: In case of excess emissions resulting from malfunctions, the permitee shall notify the Department or the appropriate Local Program in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department. [Rule 62-210.700(6), F.A.C.]

6. VOC or OS Emissions: No person shall store, pump, handle, process, load, unload or use in any process or installation, volatile organic compounds or organic solvents without applying known and existing vapor emission control devices or systems deemed necessary and ordered by the Department. [Rule 62-296.320(1), F.A.C.]

7. Objectionable Odor Prohibited: No person shall cause, suffer, allow or permit the discharge of air pollutants, which cause or contribute to an objectionable odor. An "objectionable odor" means any odor present in the outdoor atmosphere which by itself or in combination with other odors, is or may be harmful or injurious to human health or welfare, which unreasonably interferes with the comfortable use and enjoyment of life or property, or which creates a nuisance. [Rules 62-296.320(2) and62-210.200(203), F.A.C.]

8. General Visible Emissions: No person shall cause, let, permit, suffer or allow to be discharged into the atmosphere the emissions of air pollutants from any activity equal to or greater than 20 percent opacity. [Rule 62-296.320(4)(b)1, F.A.C.]

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.]

TESTING REQUIREMENTS

10. Required Number of Test Runs: For mass emission limitations, a compliance test shall consist of three complete and separate determinations of the total air pollutant emission rate through the test section of the stack or duct and three complete and separate determinations of any applicable process variables corresponding to the three distinct time periods during which the stack emission rate was measured; provided, however, that three complete and separate determinations shall not be required if the process variables are not subject to variation during a compliance test, or if three determinations are not necessary in order to calculate the unit's emission rate. The three required test runs shall be completed within one consecutive five-day period. In the event that a sample is lost or one of the three runs must be discontinued because of circumstances beyond the control of the owner or operator, and a valid third run cannot be obtained within the five-day period allowed for the test, the Secretary or his or her designee may accept the results of two complete runs as proof of compliance, provided that the arithmetic mean of the two complete runs is at least 20% below the allowable emission limiting standard. [Rule 62-297.310(1), F.A.C.]

11. Operating Rate During Testing: Testing of emissions shall be conducted with the emissions unit operating at permitted capacity. Permitted capacity is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. If it is impractical to test at permitted capacity, an emissions unit may be tested at less than the maximum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test rate 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 purpose of additional compliance testing to regain the authority to operate at the permitted capacity. [Rule 62-297.310(2), F.A.C.]

12. Calculation of Emission Rate: For each emissions performance test, the indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the three separate test runs unless otherwise specified in a particular test method or applicable rule. [Rule 62-297.310(3), F.A.C.]

13. Test Procedures: Tests shall be conducted in accordance with all applicable requirements of Chapter 62-297, F.A.C.

    a. Required Sampling Time. Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes. The minimum observation period for a visible emissions compliance test shall be thirty (30) minutes. The observation period shall include the period during which the highest opacity can reasonably be expected to occur.

    b. Minimum Sample Volume. Unless otherwise specified in the applicable rule or test method, the minimum sample volume per run shall be 25 dry standard cubic feet.

    c. Calibration of Sampling Equipment. Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1, F.A.C.

    [Rule 62-297.310(4), F.A.C.]

14. Determination of Process Variables

    a. Required Equipment. The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.

    b. Accuracy of Equipment. Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight 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.]

15. Sampling Facilities: The permittee shall install permanent stack sampling ports and provide sampling facilities that meet the requirements of Rule 62-297.310(6), F.A.C.

16. Test Notification: The owner or operator shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator. [Rule 62-297.310(7)(a)9, F.A.C.]

17. Special Compliance Tests: When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it shall require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department. [Rule 62-297.310(7)(b), F.A.C.]

18. Test Reports: The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department on the results of each such test. The required test report shall be filed with the Department as soon as practical but no later than 45 days after the last sampling run of each test is completed. The test report shall provide

sufficient detail on the emissions unit tested and the test procedures used to allow the Department to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information:

1) The type, location, and designation of the emissions unit tested.
2) The facility at which the emissions unit is located.
3) The owner or operator of the emissions unit.
4) The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.
5) The means, raw data and computations used to determine the amount of fuels used and materials processed, if necessary to determine compliance with an applicable emission limiting standard.
6) The type of air pollution control devices installed on the emissions unit, their general condition, their normal operating parameters (pressure drops, total operating current and GPM scrubber water), and their operating parameters during each test run.
7) A sketch of the duct within 8 stack diameters upstream and 2 stack diameters downstream of the sampling ports, including the distance to any upstream and downstream bends or other flow disturbances.
8) The date, starting time and duration of each sampling run.
9) The test procedures used, including any alternative procedures authorized pursuant to Rule 62-297.620, F.A.C. Where optional procedures are authorized in this chapter, indicate which option was used.
10) The number of points sampled and configuration and location of the sampling plane.
11) For each sampling point for each run, the dry gas meter reading, velocity head, pressure drop across the stack, temperatures, average meter temperatures and sample time per point.
12) The type, manufacturer and configuration of the sampling equipment used.
13) Data related to the required calibration of the test equipment.
14) Data on the identification, processing and weights of all filters used.
15) Data on the types and amounts of any chemical solutions used.
16) Data on the amount of pollutant collected from each sampling probe, the filters, and the impingers, are reported separately for the compliance test.
17) The names of individuals who furnished the process variable data, conducted the test, analyzed the samples and prepared the report.
18) All measured and calculated data required to be determined by each applicable test procedure for each run.
19) The detailed calculations for one run that relate the collected data to the calculated emission rate.
20) The applicable emission standard, and the resulting maximum allowable emission rate for the emissions unit, plus the test result in the same form and unit of measure.
21) A certification that, to the knowledge of the owner or his authorized agent, all data submitted are true and correct. When a compliance test is conducted for the Department or its agent, the person who conducts the test shall provide the certification with respect to the test procedures used. The owner or his authorized agent shall certify that all data required and provided to the person conducting the test are true and correct to his knowledge.

[Rule 62-297.310(8), F.A.C.]

RECORDS AND REPORTS

19. <u>Records Retention</u>: All measurements, records, and other data required by this permit shall be documented in a permanent, legible format and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. Records shall be made available to the Department upon request. [Rules 62-4.160(14) and 62-213.440(1)(b)2, F.A.C.]

20. <u>Annual Operating Report</u>: The permittee shall submit an annual report that summarizes the actual operating rates and emissions from this facility. Annual operating reports shall be submitted to the Compliance Authority by March 1st of each year. [Rule 62-210.370(2), F.A.C.]

SEMIANNUAL NSPS EXCESS EMISSIONS REPORT

FIGURE 1. SUMMARY REPORT - GASEOUS AND OPACITY EXCESS EMISSION AND MONITORING SYSTEM PERFORMANCE

[Note: This form is referenced in 40 CFR 60.7, Subpart A-General Provisions]

Pollutant *(Circle One)*: SO_2 NO_X TRS H_2S CO Opacity

Reporting period dates: From ____________________ to ____________________

Company: ______________________________

Emission Limitation: ______________________________

Address: ______________________________

Monitor Manufacturer: ______________________________

Model No.: ______________________________

Date of Latest CMS Certification or Audit: ____________________

Process Unit(s) Description: ______________________________

Total source operating time in reporting period [1]: ____________________

Emission data summary [1]	CMS performance summary [1]
1. Duration of excess emissions in reporting period due to:	1. CMS downtime in reporting period due to:
a. Startup/shutdown .... ____	a. Monitor equipment malfunctions .... ____
b. Control equipment problems .... ____	b. Non-Monitor equipment malfunctions .... ____
c. Process problems .... ____	c. Quality assurance calibration .... ____
d. Other known causes .... ____	d. Other known causes .... ____
e. Unknown causes .... ____	e. Unknown causes .... ____
2. Total duration of excess emissions .... ____	2. Total CMS Downtime .... ____
3. Total duration of excess emissions x (100) / [Total source operating time] .... ____ %[2]	3. [Total CMS Downtime] x (100) / [Total source operating time] .... ____ %[2]

1 For opacity, record all times in minutes. For gases, record all times in hours.

2 For the reporting period: If the total duration of excess emissions is 1 percent or greater of the total operating time or the total CMS downtime is 5 percent or greater of the total operating time, both the summary report form and the excess emission report described in 40 CFR 60.7(c) shall be submitted.

Note: On a separate page, describe any changes since the last in CMS, process or controls.

I certify that the information contained in this report is true, accurate, and complete.

Name: ______________________________

Signature: ______________________________ *Date*: ____________________

Title: ______________________________

PUBLIC NOTICE

On July 31, 2002, the Department distributed a draft permit package that authorizes the construction of Unit 8 at the existing Martin Power Plant, which is located approximately 7 miles north of Indiantown on State Road 710 in Martin County, Florida. Unit 8 will be a "4-on-1" combined cycle gas turbine system with an electrical generating capacity of approximately 1150 MW. The "Public Notice of Intent to Issue Permit" was published in the Indiantown News on September 12, 2002. The Department received the proof of publication on September 27, 2002.

The applicant requested, and received from the Department, two orders granting additional time in which to file a petition for an administrative hearing. On December 9, 2002, the applicant made a third such request. However, on December 20, 2002, the applicant withdrew the last request based on the revised draft permit as agreed to with the Department. There were no other requests for extensions or petitions filed on this project.

COMMENTS

EPA Region 4

Comment 1. On August 28, 2002, the Department received comments from EPA Region 4 regarding the draft permit. EPA's single comment focuses on the BACT determination for nitrogen oxides when operating in simple cycle mode. EPA notes that the applicant did not consider the option of reducing the exhaust gas temperature to within the conventional SCR catalyst operational range for running in simple cycle mode. EPA requested that the Department evaluate the technical feasibility of this option and, if technically feasible, the economics, environmental impacts, and energy use aspects of this option.

Response: The Department contacted an engineer in California's South Coast Air Quality Management District and discussed exhaust cooling for a project using a simple cycle Frame 7EA gas turbine employing a "hot" SCR catalyst. The cooling was necessary to prevent irreversible damage to the catalyst due to potential temperature excursions above 1000° F. Most conventional catalysts require an operational temperature range of approximately 400° F to 700° F, which would mean substantially higher cooling air flow rates as well as raise additional concerns regarding the potential risks for catalyst damage. The Department was unable to find a similar project for a Frame 7FA gas turbine that employed sufficient exhaust cooling to allow the use of a conventional SCR catalyst. The design basis of the FPL Martin project is to construct and operate a base-loaded, 4-on-1 combined cycle system. FPL currently operates similar base-loaded combined cycle units at the Martin Plant. FPL's request for some simple cycle operation is to accommodate possible scenarios when a HRSG or steam-electrical generator is not functional. EPA's exhaust cooling scenario could not be applied in the case where repair work had to be performed on the HRSG. The permit allows limited simple cycle operation (1000 hours/year) once construction is completed for combined cycle operation. The permitted NOx standards for this very limited simple cycle operation compare favorably with many other similar simple cycle projects. Although such cooling would be technically possible, the Department did not require the applicant to evaluate this concept further based on the specifics of this project. The Department may require such an evaluation for future projects.

Comment 2. On February 5, 2003, the Department received a letter from EPA Region 4 in response to a request for a determination of applicability of Subpart Dc with regard to the gas-fired fuel heaters. Subpart Dc is a federal New Source Performance Standard that regulates small industrial-commercial-institutional steam generating units. EPA stated that the fuel heaters are not subject to NSPS Subpart Dc.

Response: The Department concurs. Conditions related to NSPS Subpart Dc were removed from the final permit.

Applicant

The applicant provided several comments on the draft permit in writing, via email, and in person. The following summarizes many of the changes that the Department agreed to make as a result of these comments.

Cover Page: The permit expiration date is extended from 12/30/05 to 12/30/06 to provide sufficient time to construct, test, and obtain Title V operation permit. Under "Project and Location", a new note is added to clarify that references to the electrical generating capacities (MW) in the permit relate to nominal values for the given operating conditions. Throughout the remaining permit, the word "nominal" is deleted with regard to the generating capacities (MW).

Section I. General Information

Page 2, New and Modified Units: The description for Emissions Unit 013 is revised to indicate that "four" fuel heaters that comprise this unit. There are two previously permitted fuel heaters and two new fuel heaters. The description of Emissions Unit 014 is revised to clarify that this unit represents two distillate oil storage tanks, one existing tank and one new tank.

Page 2, Regulatory Classification: References to NSPS and NESHAP are removed because these unit-specific requirements are discussed under the appropriate emissions unit sections.

Page 3, Appendices: A reference is added for Appendix XS, which is the "Continuous Monitor Systems Semi-Annual Report".

Page 3, Relevant Documents: A reference is added for previously issued Permit No. PSD-FL-286.

Page 4, Condition No. 3: The condition is revised to clarify that it is necessary to demonstrate the adequacy of previous BACT determinations when construction has not commenced within 18 months or construction has been delayed for 18 months.

Section III A. Unit 8 – "4 on 1" Combined Cycle Gas Turbine

Page 5, Emissions Unit Description: Added note following stack parameters, "The Department may require the permittee to perform additional air dispersion modeling should the actual specified stack dimensions change." The flow rate was corrected for oil firing during simple cycle operation from 2,745,300 acfm to 2,464,300 acfm.

Page 5, Condition 2: The condition is updated to reflect Appendix Da and to remove the reference to Appendix Dc, which is removed.

Page 6, Condition 3: The simple cycle stack dimensions are removed because the dimensions are already provided in the emissions unit description.

Page 6, Condition 4a: To clarify that the units must be tuned to achieve the NOx and CO emission levels during simple cycle operation, the second sentence is reworded to, "Prior to the initial emissions performance tests required for each gas turbine, the DLN combustors and automated gas turbine control system shall be tuned to achieve the simple cycle permitted levels for CO and NOx emissions." Also, the following permitting note is added to clarify that there are two existing gas turbines, "Initial tuning has been completed for Emissions Unit Nos. 011 and 012."

Page 6, Condition 4b: Similar to Condition 4a above, the condition is reworded to, "The permittee shall install, operate, and maintain a water injection system to reduce NOx emissions from each gas turbine when firing distillate oil. Prior to the initial emissions performance tests required for each gas turbine, the water injection system shall be tuned to achieve the permitted levels for CO and NOx emissions. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations. The automated control system shall be programmed to establish a water-to-fuel ratio designed to achieve the NOx emission standard for simple cycle oil firing on a 1-hour basis. *{Permitting Note: Initial tuning has been completed for Emissions Unit Nos. 011 and 012.}*"

Page 6, Condition 4c: The last sentence is reworded to, "The SCR system shall be designed, constructed and operated to achieve the permitted levels for NOx emissions and ammonia slip." Also, the permitting note is reworded to, "*In* accordance with 40 CFR 60.130, the storage of ammonia shall comply with all applicable requirements of the Chemical Accident Prevention Provisions in 40 CFR 68."

Page 6, Condition 5: The HRSG stack dimensions are removed from this condition because they are already provided in the emissions unit description. The requirement to install a "stack damper" is removed because it would have little impact on the types of shutdowns expected for these base-loaded units. FPL's 2000-2001 annual operating reports for the existing 2-on-1 combined cycle Martin Units 3 and 4 show an annual capacity factor of 90% or more for the past two years. This supports FPL's claim that the new combined cycle Unit 8 will be a base-loaded unit. Therefore, the condition is reworded to, "The permittee is authorized to install, operate, and maintain four new heat recovery steam generators (HRSGs) with separate HRSG exhaust stacks. Each HRSG shall be designed to recover heat energy from one of the four gas turbines (8A-8D) and deliver steam to the steam turbine electrical generator through a common manifold. Each HRSG may be equipped with supplemental gas-fired duct burners having a maximum heat input rate of 495 MMBtu per hour (LHV). The duct burners shall be designed in accordance with the following specifications: 0.04 lb CO/MMBtu and 0.08 lb NOx/MMBtu. *{Permitting Note: The four HRSGs deliver steam to a single steam turbine-electrical generator with a generating capacity of 470 MW.}*"

Page 7, Condition 6: To clarify that the maximum heat input rate is an equipment specification, the first sentence is reworded to, "The maximum heat input rate to each gas turbine is 1600 MMBtu per hour when firing natural gas and 1811 MMBtu per hour when firing distillate oil (based on a compressor inlet air temperature of 59° F, the lower heating value (LHV) of each fuel, and 100% load)."

Page 7, Condition 7: To clarify that the maximum heat input rate is an equipment specification, the first sentence is reworded to, "The total maximum heat input rate to the duct burners for each HRSG is 495 MMBtu per hour based on the lower heating value (LHV) of natural gas."

Page 7, Condition 8d: To clarify SCR operation, the last sentence is reworded to, "In accordance with the specifications of the SCR and HRSG manufacturers, the SCR system shall be on line and functioning properly during combined cycle operation or when the HRSG is producing steam."

Page 8, Condition 8g: To clarify that the total combined operation of power augmentation and peaking modes shall not exceed 400 hours during any consecutive 12 months per unit, the condition is reworded to, "Total combined operation of power augmentation and peaking modes shall not exceed 400 hours per unit during any consecutive 12 months."

Page 8, Condition 8h: To satisfy the FPL's initial application request that duct firing be limited based on fuel consumption and not hours, the condition is reworded to, "The total combined heat input rate to the duct burners (all four HRSGs) shall not exceed 5,702,400 MMBtu (LHV) during any consecutive 12 months." This is the equivalent heat input rate for 2880 hours per year of duct firing, which was the previous permit requirement.

Page 8, Condition 9: The condition specifying the emissions standards are revised as follows:

- The emissions standards table is reformatted for clarity.
- Additional information is added to the note following the table, which is reworded to, "*{Permitting Notes: "DB" means duct burning. "PA" means power augmentation. "SCR" means selective catalytic reduction. "NA" means not applicable. The mass emission rate standards are based on a turbine inlet condition of 59° F and may be adjusted to actual test conditions in accordance with the performance curves and/or equations on file with the Department. Initial compliance tests under normal conditions for gas and oil firing have already been conducted for the existing Unit 8 gas turbines.}*"
- The column labeled "Initial" is revised to "Stack Test, 3-Run Averages" to clarify the basis of the standard as opposed to the adjacent column, which is labeled "CEMS". To clarify that the standards are not rolling

averages, the term "Block Averages" is added to the "CEMS" column.

- For firing natural gas, the CO emissions standards are separated into "simple cycle" and "combined cycle" operation. No change is made to the standards for simple cycle operation. For combined cycle operation, the CO standards are separated into "Normal" operation (which does not include duct firing, power augmentation, or peaking) and "All Modes" (which includes any mode of operation). For operation in any mode other than "normal", the CO CEMS standard is simplified to "10.0 ppmvd @ 15% O_2 based on a 24-hour average". The revised standard allows the operator to manage the CO emissions to comply with the permit requirements while ensuring efficient combustion and operation. The initial draft permit allowed 8 ppmvd @ 15% O_2 for operation with and without duct firing and 12 ppmvd @ 15% O_2 with power augmentation. The revised standard is equivalent to a day with 12 hours of normal operation combined with 12 hours of power augmentation at the previously permitted levels. The Department believes that the revised standard is as stringent as the original levels and represents BACT for combined cycle gas turbines.
- For firing natural gas, the averaging period of the NOx standards for simple cycle peaking and power augmentation are changed to a 24-hour average basis of hours operated in that mode. This is consistent with the way in which the CO emission standards are written. Compliance could be determined on as little as one hour of data or as much as 24 hours of data. However, it is unlikely that a unit would be operated in one of these high-power modes for more than a few hours per day. The Department believes that the revised standard is as stringent as the original levels and represents BACT for simple cycle gas turbines.
- For combined cycle operation while firing natural gas, the table format is changed similar to that for the CO standards. The NOx mass emissions rate for simple cycle peaking when firing gas is corrected from 101.3 to 95.3 lb/hour (based on turbine inlet conditions of 59° F). Similarly, the NOx mass emissions rate for combined cycle duct firing when firing natural gas is corrected from 22.1 to 23.6 lb/hour (based on turbine inlet conditions of 59° F).
- The VOC mass emissions rate for combined cycle duct burning/power augmentation when firing natural gas is corrected from 9.2 to 10.5 lb/hour (based on turbine inlet conditions of 59° F).
- Consistent with other recently issued PSD permits, the ammonia slip standard is revised from 5.0 to 5 ppmvd @ 15% O_2. Condition 9f is revised to, "Subject to the requirements of Condition No. 23 of this section, each SCR system shall be designed and operated for an initial ammonia slip target of less than 5 ppmvd corrected to 15% oxygen based on the average of three test runs."
- Conditions 9a through 9f are updated according to the changes discussed.

Page 9, Condition 10: To clarify that there is not a separate *dump* condenser, condition is reworded to, "If the steam-electrical turbine generator is off line, the permittee is authorized to operate the gas turbine/HRSG systems by dumping steam to the condenser. When operating in this manner, each unit shall comply with the standards established for combined cycle operation with ammonia injection (SCR)." The permitting note regarding inefficient operation when dumping steam is removed, as it is unnecessary.

Page 9, Condition 11: With regard to the NSPS standards for the duct burners, the following permitting note is added, "During duct firing, compliance with the limits of this permit also demonstrates compliance with the standards of NSPS Subpart Da for duct burners."

Page 10, Condition 12: To clarify the phasing-in of the combined cycle project with the two existing gas turbines, the condition is reworded to, "Until commencement of the initial steam blows, the terms and conditions of Air Permit No. PSD-FL-286 shall apply to the two existing Unit 8 gas turbines (Emissions Unit Nos. 011 and 012), the two existing gas-fired fuel heaters (Emissions Unit 013) and the distillate oil storage tank (Emissions Unit 014). Thereafter, this PSD permit shall replace and supersede Air Permit No. PSD-FL-286. *{Permitting Note: Initial tests on gas and oil under normal conditions during simple cycle operation have already been conducted for the existing Unit 8 gas turbines.}*"

Page 10, Condition 16: The applicant provided additional information regarding startup of the 4-on-1 combined cycle unit when the steam turbine electrical generator is cold. For such a startup, it is imperative that the steam turbine be gradually warmed up before full load operation to prevent thermal metal fatigue and premature failure. (Similarly, it may be necessary to gradually cool the system during a shutdown.) The relatively unique combination of four gas turbine/HRSG systems supplying steam to a common steam turbine further complicates such startups. The procedure begins with the startup of a single gas turbine/HRSG system operating at very low loads (< 10%). This unit may operate under these conditions from four to six hours depending on the length of shutdown and the steam turbine temperature. Approximately two to three hours into the cold steam turbine startup, a second gas turbine/HRSG system is brought on line under the low load conditions. The third and fourth gas turbine/HRSG systems are eventually brought on line in a similar manner. The entire steam turbine cold startup is complete within 12 hours.

Cycling such units through the range of low temperatures to high temperatures increases the risk of equipment failure. Such operation also increases the frequency of maintenance intervals, which adds to operating costs. Therefore, operators of base-loaded units have every incentive to minimize the frequency of cold steam turbine startups and shutdowns. For example, FPL recently re-powered the Ft. Myers plant with a similar 4-on-1 combined cycle gas turbine system. The unit has been operating approximately six months and has had but one cold steam turbine startup.

The Department's rules require that the duration of excess emissions due to startup, shutdown, or malfunction be minimized, but that, "... in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration." Although emission concentrations can be much higher than permitted standards during startups, operation at such low loads also means less fuel consumption, mass flow rates, and lower mass emission rates. Considering all of this information the, the condition is revised to:

"16. Excess Emissions Allowed: As specified in this condition, excess emissions resulting from startup, shutdown, oil-to-gas fuel switches and documented malfunctions are allowed provided that operators employ the best operational practices to minimize the amount and duration of emissions during such incidents. A "documented malfunction" means a malfunction that is documented within one working day of detection by contacting the Compliance Authority by telephone, facsimile transmittal, or electronic mail. For each gas turbine/HRSG system, excess emissions resulting from startup, shutdown, or documented malfunctions shall not exceed two hours in any 24-hour period except for the following specific cases.

a. For cold startup of the steam turbine system, excess emissions from any gas turbine/HRSG system shall not exceed six hours in any 24-hour period. Cold startup of the steam turbine system shall be completed within twelve hours. A cold "startup of the steam turbine system" is defined as startup of the 4-on-1 combined cycle system following a shutdown of the steam turbine lasting at least 48 hours. *{Permitting Note: During a cold startup of the steam turbine system, each gas turbine/HRSG system is sequentially brought on line at low load to gradually increase the temperature of the steam-electrical turbine and prevent thermal metal fatigue. Note that shutdowns and documented malfunctions are separately regulated in accordance with the requirements of this condition.}*

b. For shutdown of the steam turbine system, excess emissions from any gas turbine/HRSG system shall not exceed three hours in any 24-hour period.

c. For cold startup of a gas turbine/HRSG system, excess emissions shall not exceed four hours in any 24-hour period. "Cold startup of a gas turbine/HRSG system" is defined as a startup after the pressure in the high-pressure (HP) steam drum falls below 450 psig for at least a one-hour period.

d. For oil-to-gas fuel switching in simple cycle operation, excess emissions shall not exceed 1 hour in any 24-hour period.

Ammonia injection shall begin as soon as operation of the gas turbine/HRSG system achieves the operating parameters specified by the manufacturer. As authorized by Rule 62-210.700(5), F.A.C., the above conditions allow excess emissions only for specifically defined periods of startup, shutdown, and documented malfunction of the gas turbines. [Design; Rules 62-212.400(BACT) and 62-210.700, F.A.C.]"

The above revised condition adds a definition for "documented malfunction", which was inadvertently omitted from the original condition. Also, the original condition limiting "warm startups" is replaced with one limiting "cold gas turbine/HRSG startups", which is more appropriate. Finally, there is a new allowance for excess emissions due to an oil-to-gas fuel switch. This type of switch requires the unit to be brought down to low loads and cycled back through the lean premix combustion stages, which can lead to a brief period of excess emissions. Conversely, a gas-to-oil fuel switch can occur readily as oil is added and the water injection system is initiated. Therefore, one hour of excess emissions in any 24-hour period is allowed due to an oil-to-gas fuel switch. The revisions are based on the unique equipment design for this project and are not expected to result in any increased incidents of excess emissions due to startup, shutdown, malfunction, or fuel switches.

Page 10, Condition 17: The following text is added to the first paragraph, "For good cause, the permittee may request that the Compliance Authority extend the steam blow period." The notification period is changed from "24-hours" to "one working day". Also, the following sentence is added to the permitting note, "This condition only applies if simple cycle operation begins prior to combined cycle operation and NSPS compliance tests for simple cycle operation have been performed."

Page 11, Condition 19: EPA Method 5 is removed, as this test is not required by permit.

Page 12, Condition 20: To reflect the NSPS requirements for conducting initial tests, the second sentence is revised to, "The tests shall be conducted within 60 days after achieving the maximum production rate at which the unit will be operated for each unit configuration (i.e., simple cycle and combined cycle operation), but not later than 180 days after the initial startup of each unit configuration." In the third sentence, the phrase "(or fuel measurements and approved F-factors)" is substituted for the words "and calculations" to clarify the meaning. The last sentence is revised to, "The Department may require the permittee to conduct additional tests after major replacement or major repair of any air pollution control equipment, such as the SCR catalyst, DLN combustors, etc."

Page 12, New Condition 23: The following new condition is inserted as Condition No. 23.

"23. Additional Ammonia Slip Testing: If the tested ammonia slip rate for a gas turbine exceeds 5 ppmvd corrected to 15% oxygen when firing natural gas during the annual test, the permittee shall:

a. Begin testing and reporting the ammonia slip for each subsequent calendar quarter;

b. Before the ammonia slip exceeds 7 ppmvd corrected to 15% oxygen, take corrective actions that result in lowering the ammonia slip to less than 5 ppmvd corrected to 15% oxygen; and

c. Test and demonstrate that the ammonia slip is no more than 5 ppmvd corrected to 15% oxygen within 15 days after completing the corrective actions.

Corrective actions may include, but are not limited to, adding catalyst, replacing catalyst, or other SCR system maintenance or repair. After demonstrating that the ammonia slip level is no more than 5 ppmvd corrected to 15% oxygen, testing and reporting shall resume on an annual basis. [Rules 62-4.070(3) and 62-297.310(7)(b), F.A.C.]"

The new condition requires the permittee to take corrective action should the ammonia slip exceed 5 ppmvd @ 15% O_2 and begin more frequent monitoring. Note that all of the subsequent conditions are renumbered accordingly.

Page 12, Condition 23(24): Original condition 23 is renumbered to "24". Minor rewording to, "Each monitoring system shall be installed, calibrated, and properly functioning prior to the initial performance tests. Within one working day of discovering emissions in excess of a CO or NOx standard (and subject to the specified averaging period), the permittee shall notify the Compliance Authority."

24a: This condition is reworded to clarify that the CO monitor span values must be set appropriately considering the allowable methods of operation and corresponding emission standards.

24b: This condition is reworded to clarify that the NOx monitor is to be certified in accordance with the acid rain requirements (acid rain) and shall also be used for compliance with the permit emissions standards.

24c: The acid rain program requires the use of a diluent monitor, which can be either oxygen or carbon dioxide. The condition is reworded to clarify that such diluent monitors shall be certified in accordance with 40 CFR 75, which is part of the acid rain monitoring program.

24d: The following sentence is added, "For purposes of determining compliance with the CEMS emissions standards of this permit, missing (or excluded) data shall not be substituted." The acid rain program allows data substitution for determining the long-term NOx emission rates; however, this is not appropriate for determining compliance with short-term averages. To clarify the appropriate standard when two fuels are fired within the same 1-hour block, the following sentence is added, "An hour in which any oil is fired is attributed towards compliance with the permit standards for oil firing."

24g: The first two sentences are revised to, "Each CEMS shall monitor and record emissions during all operations including episodes of startup, shutdown, malfunction, fuel switches, DLN tuning, and steam blows. CEMS emissions data recorded during some of these episodes may be excluded from the corresponding CEMS compliance demonstration subject to the provisions of Condition Nos. 16 and 18 of this section." This is just a minor rewording to clarify the episodes covered.

24h: The last sentence is revised as follows to add the trailing clause, "Failure to take corrective actions or continued failure to achieve the minimum monitor availability shall be violations of this permit, except as otherwise authorized by the Department's Compliance Authority."

The term "Subpart Da" is added to the regulatory requirements in the permitting note.

Page 14, Condition 24(25): Original condition 24 is renumbered to "25". The following sentence is added, "The NOx CEMS is used to demonstrate compliance with the NOx emissions standards." The following sentence is added to the permitting note, "The actual water-to-fuel ratio will vary depending on operating conditions and load."

Page 14, Condition 26(27): Original condition 26 is renumbered to "27". The first sentence is revised to, "The permittee shall monitor and record the operating rate of each gas turbine and HRSG duct burner system on a daily average basis, considering the number of hours of operation during each day (including the times of startup, shutdown and malfunction)."

Page 15, Condition 29(30): Original condition 29 is renumbered to "30". Consistent with Rules 62-4.130 and 62-210.700(6), F.A.C., this condition is reworded to, "Within one working day of a malfunction that causes emissions in excess of a standard (subject to the specified averaging periods), the permittee shall notify the Compliance Authority. The notification shall include a preliminary report of: the nature, extent, and duration of the emissions; the probable cause of the emissions; and the actions taken to correct the problem. If requested by the Compliance Authority, the permittee shall submit written quarterly reports the malfunctions."

Section III B. Gas-Fired Fuel Heaters: Based on EPA Region 4's interpretation, all references to NSPS Subpart Dc were removed and replaced with the following permitting note.

{Permitting Note: FPL requested a determination from the Department on the applicability of NSPS Subpart Dc to the gas-fired fuel heaters. The Department agreed with FPL that it did not believe that

Subpart Dc should apply to these units, but referred the request to EPA Region 4 for interpretation of the federal standards. In a letter dated February 5, 2003, EPA Region 4 concurred that Subpart Dc did not apply to the gas-fired fuel heaters.}

Section III C. Cooling Tower: Condition 2 is revised to clarify that the cooling tower will be designed to achieve the specified drift rate. The permittee is also required provide a certification of this requirement.

Section III D. Distillate Storage Tank: This new subsection is added to identify the requirements from previous Air Permit No. PSD-FL-286, which this new PSD permit will eventually replace. The conditions and descriptions clarify there will be two, 2.1 million gallon distillate oil storage tanks (one existing tank and one new tank). Both tanks are available for the Unit 8 combined cycle system.

Section IV. Appendices

Appendix A (NSPS General Provisions): A new appendix added that lists the individual general provisions for NSPS units.

Appendix BD (BACT Determinations and Emissions Standards): The appendix is updated to reflect any changes in the emissions standards made in the draft permit, which were previously discussed.

Appendix Da (Duct Burners): The appendix is completely updated to reflect a more thorough presentation of the Subpart Da requirements. In general, the duct burners are subject to a NOx standard of 1.6 lb/MW-hr gross energy output. An initial compliance test is required. Thereafter, compliance with the BACT standard (2.5 ppmvd @ 15% O_2) will be adequate to show compliance with the NSPS standard.

Appendix Dc (Gas-Fired Fuel Heaters): Appendix Dc is deleted because the gas-fired fuel heaters are not subject to NSPS Subpart Dc.

Appendix GG (Gas Turbines): Appendix GG is completely updated to reflect a more thorough presentation of the Subpart GG requirements, which is similar to other recently issued PSD permits.

Appendix XS (Semiannual NSPS Excess Emissions Report): At the request of the applicant, the NSPS report format was added for the reporting emissions in excess of the NSPS standards.

Other Comments

No comments were received from the Department's Southeast District Office, the National Park Service, or the public.

REVISED DRAFT PERMIT

Based on comments made by the applicant, the Department agreed to the above changes. The changes were not considered substantial. On December 10, 2002, the revised draft permit was submitted to the Department's Siting Office for inclusion in the draft power plant site certification. A copy of the revised draft permit and a summary of the proposed changes were provided to EPA Region 4 by email on December 11, 2002. On December 31, 2002, EPA Region 4 contacted the Department by email and indicated that it had no additional comments on the proposed changes to the draft permit. The revised draft permit and a summary of the changes were posted on the Department's web site. The draft certification document (including the revised PSD permit conditions) was presented at the site certification hearing held on April 8, 2003. The project received no adverse comments regarding air quality. A final order for site certification was issued on April 11, 2003.

CONCLUSION

The final action of the Department is to issue the final permit as presented at the site certification hearing. Note that conditions regarding NSPS Subpart Dc were removed because EPA determined that this Subpart was not applicable to the fuel heaters.

Memorandum

Florida Department of Environmental Protection

TO: Howard L. Rhodes, Division of Air Resources Management

THRU: Trina Vielhauer, Bureau of Air Regulation TV
Al Linero, New Source Review Section aal

FROM: Jeff Koerner JK

DATE: April 11, 2003

SUBJECT: Project No. 0850001-010-AC
Air Permit No. PSD-FL-327
FPL Martin Power Plant
New Combined Cycle Unit 8

The Final Permit is attached for your approval and signature for a project that authorizes the construction of Unit 8 at the existing Martin Power Plant, a "4-on-1" combined cycle unit with an electrical generating capacity of approximately 1150 MW. The project will utilize two existing 170 MW gas turbine-electrical generator sets and will add two new 170 MW gas turbine-electrical generator sets, four new heat recovery steam generators, a single 470 MW steam turbine-electrical generator, gas-fired fuel heaters, and a mechanical draft cooling tower. The project is subject to power plant site certification.

On July 31, 2002, the Department distributed a draft permit package. The "Public Notice of Intent to Issue Permit" was published in the Indiantown News on September 12, 2002. The Department received the proof of publication on September 27, 2002. The applicant requested, and received from the Department, two orders granting additional time in which to file a petition for an administrative hearing. On December 9, 2002, the applicant made a third such request. However, on December 20, 2002, the applicant withdrew the last request based on the revised draft permit as agreed to with the Department. There were no other requests for extensions or petitions filed on this project.

Changes to the draft permit are summarized in the attached Final Determination. The changes were not considered substantial. On December 10, 2002, the revised draft permit was submitted to the Department's Siting Office for inclusion in the draft power plant site certification. A copy of the revised draft permit and a summary of the proposed changes were provided to EPA Region 4 by email on December 11, 2002. On December 31, 2002, EPA Region 4 contacted the Department by email and indicated that it had no additional comments on the proposed changes to the draft permit. The revised draft permit and a summary of the changes were posted on the Department's web site. The draft certification document (including the revised PSD permit conditions) was presented at the site certification hearing held on April 8, 2003. The project received no adverse comments regarding air quality. The Governor and Cabinet approved the site certification.

I recommend your approval and signature.

Attachments

Golder Associates Inc.

6241 NW 23rd Street, Suite 500
Gainesville, FL 32653-1500
Telephone (352) 336-5600
Fax (352) 336-6603

Golder Associates

October 8, 2002

0137609

RECEIVED

OCT 10 2002

BUREAU OF AIR REGULATION

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

RE: FPL MARTIN EXPANSION PROJECT
EPA COMMENTS TO DRAFT PERMIT
PROJECT NO. 085001-010-AC (PSD-FL-327)

Attention: Mr. Jeffery Koerner, P.E.

Dear Jeff:

This correspondence provides information requested by EPA Region IV regarding the technical feasibility of using the conventional SCR system during simple cycle operation by reducing the temperature of the exhaust gases. One method mentioned by EPA Region IV is to reduce the exhaust temperature using ambient air. This method is the only method currently used to reduce the exhaust gas temperature of combustion turbines for the installation of "Hot SCR" systems on some simple cycle turbines.

The Martin Unit 8 Project will be designed as a "4-on-1" combined cycle unit. Simple cycle operation will only occur for Units 8A and 8B prior to conversion to combined cycle and potentially for Units 8C and 8D. Units 8A and 8B are existing simple cycle units that will be converted to combined cycle mode. Simple cycle operation for Units 8C and 8D would potentially occur during the first year of operation of the combustion turbines (CTs). When the Martin Unit 8 combined cycle unit is operational, simple cycle operation without the SCR system operating would potentially average 1,000/CT for the four CTs. This would only occur if the heat recovery steam generator (HRSG)/CT systems or steam turbine were not operational for an extended period. The SCR systems would be internal to the HRSG at a location where the temperature of the air stream was about 650 degrees Fahrenheit (°F). The HRSG would provide the necessary cooling of the CT exhaust gases to 650°F by extracting heat from the high-temperature CT exhaust gases (typically 1,100 to 1,200°F) and producing steam.

In the event simple cycle operation (i.e., exhaust through a simple cycle stack without going through the HRSG) is maintained, it would not be technically feasible to use the conventional SCR and still maintain normal combined cycle operation. While this may be theoretically possible, such a design would not be technically feasible for the project for the reasons summarized below:

- To use the SCR system in each HRSG, the exhaust gases would have to be cooled prior to the CT/HRSG transition, mixed, and uniformly distributed prior to the SCR system. This would require a large flue duct system that would not fit within any practical arrangement of a 4-on-1 combined cycle unit.

- The HRSG tubes would have to withstand 650°F while not producing steam (i.e., dry). This would require material upgrades that would affect overall performance in combined cycle mode. Moreover, the reason that simple cycle may be used would be some malfunction of the HRSG. Such malfunctions (e.g., repair of tube leaks) would require work directly in the HRSG and, thus, operation in simple cycle could not occur. If only one CT/HRSG train was inoperable, Martin Unit 8 could still be operated in combined cycle mode using three CT/HRSG trains. Finally, experience with the existing FPL combined cycle units (Martin Units 3 and 4 and Lauderdale Units 4 and 5) have demonstrated that the steam turbines are rarely shutdown for extended periods, making simple cycle operation very unlikely.
- Introducing cooled exhaust air through the SCR system and only a portion of the HRSG would not be feasible. Any cooled CT exhaust gases routed around the HRSG sections prior to the ammonia injection grid and into the SCR catalyst would have to flow parallel to the HRSG. The SCR catalyst is directional and it would not be possible to properly distribute exhaust gases in such a configuration.
- A temperature reduction of about 450°F in the CT exhaust temperature has not been demonstrated on any CT exhaust using an "F" Class turbine. The amount of cooling air would be about 25 percent of the CT exhaust flow and require large air injection fans. The large amount of air required would substantially increase the pressure drop for all systems. Finally, the SCR system itself would be larger to accommodate the large mass flow. In combined cycle mode, these factors would significantly affect the performance of the unit.

Please contact me if there are any questions.

Sincerely,

GOLDER ASSOCIATES INC.

Kennard F. Kosky

Kennard F. Kosky, P.E.
Principal

KFK/nav

cc: K. H Simmons, Manager of New Capacity Projects
C. Holladay
P:\Projects\2001\0137609 FPL Fort Myers-Martin-Manatee\4.1\L100802.doc
B. Oven
J. Little, SED
G. Hettle, EPA
G. Bunyak, NPS

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Writer's Direct Dial No.
(850) 425-2320

September 27, 2002

Mr. A. A. Linero, P.E.
Bureau of Air Regulation
Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399

Re: Florida Power & Light Co., Martin Unit 8
OGC Case No. 02-1209
PSD Permit No. PSD-FL-327
Project No. 0850001-010-AC

Dear Al:

Enclosed for your files are the original Proofs of Publication from the Indiantown News and The Stuart News for the above-referenced Public Notice of Intent to Issue PSD Permit for the FPL Martin Power Plant, New Combined Cycle Unit 8 in Martin County, Florida. Both notices were published on September 12, 2002.

Please do not hesitate to call me if you have any questions concerning the above.

Sincerely,

Doug Roberts

Douglas S. Roberts

Encls.

cc: Jeff Koerner (w/o attachments)
Ken Simmons (w/attachments)
J. Little, SED
B. Oven, DEP
J. Bunyak, NPS
G. Dettle, EPA

AFFIDAVIT OF PUBLISHER

Indiantown News
P.O. Box 1080, Indiantown, Fl 34956
(561) 597-4243
Published Weekly

RECEIVED
SEP 27 2002
BUREAU OF AIR REGULATION

STATE OF FLORIDA
COUNTY OF MARTIN

Before the undersigned authority personally appeared J.W. Owens who on oath says that he is publisher of the Indiantown News, a newspaper published weekly at Indiantown in Indiantown, Florida:

that the attached copy of advertisement,
being a Public Notice of Intent to Issue PSD Permit
in the matter of FPL Martin Power Plan, New Combined Cycle Unit 8
via: Gail Steels
Hopping, Green & Sams
123 S. Calhoun Street
Tallahassee, FL 32301

In the ______________________ Court,
was published in said newspaper in the issues of 09/12/2002

Affiant further says that the said Indiantown News is a newspaper published at Indiantown, in said Martin County, Florida, and that said newspaper has heretofore been continuously published in said Indiantown, Florida as a daily, weekly, or bi-weekly and has been entered as second class mail matter at the post office in Indiantown, in said Martin County, Florida, for a period of one year next preceding the first publication of the attached copy of advertisement; and affiant further says that he has neither paid nor promised any person, firm or corporation any discount, rebate, commission or refund for the purpose of securing this advertisement for publication in the said newspaper.

J. W. Owens, (Publisher)
Sworn to and subscribed before me
this 12th day of September
A.D. 2002

Rosealee A. Brennan
(SEAL) Notary Public

NOTARY PUBLIC STATE OF FLORIDA
OFFICIAL NOTARY SEAL
ROSEALEE A BRENNAN
COMMISSION NUMBER
CC 940770
MY COMMISSION EXPIRES
JUNE 25,2004

PUBLIC NOTICE OF INTENT TO ISSUE PSD PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
Draft Permit No. PSD-FL-327
FPL Martin Power Plant, New Combined Cycle Unit 8
Martin County

The Department of Environmental Protection (Department) gives notice of its intent to issue a permit under the requirements for the Prevention of Significant Deterioration (PSD) of Air Quality to the Florida Power and Light Company. The permit is one of several authorizations needed to construct a nominal 1150 MW combined cycle gas project at the FPL Martin Power Plant, which is located approximately 7 miles north of Indiantown on State Road 710 in Martin County, Florida. In accordance with Rule 62-212.400, F.A.C. and 40 CFR 52.21, Best Available Control Technology (BACT) determinations were required for emissions of carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), sulfuric acid mist (SAM), and volatile organic compounds (VOC). The applicant's authorized representative is Mr. John M. Lindsay, Plant General Manager. The applicant's address is FPL Martin Power Plant, P.O. Box 176, Indiantown, FL 34956.

The applicant proposes to construct a "4-on-1" combined cycle Unit 8 consisting of the following equipment and specifications: two existing 170 MW simple cycle gas turbine-electrical generator sets (8A and 8B), two new 170 MW gas turbine-electrical generator sets (8C and 8D), four gas-fired heat recovery steam generators (495 MMBtu/hour, LHV), a common steam-electrical generator (470 MW), two new gas-fired fuel heaters (22 MMBtu/hour, each), a cooling tower, and other associated support equipment. The gas turbines will be fired primarily with natural gas and up to 500 hours per year of very low sulfur distillate oil as a restricted alternate fuel. For the first year of operation, each gas turbine may operate in simple cycle mode for 3390 hours per year while the combined cycle components are constructed. Once combined cycle operation is established, simple cycle operation is limited to an average of 1000 hours per year. Additional equipment includes four 120-foot stacks combined cycle stacks, four 80-foot simple cycle stacks, and an aqueous ammonia storage tank.

During simple cycle operation and gas firing, NOx emissions will be controlled by dry low-NOx combustion technology. During simple cycle operation and oil firing, NOx emissions will be controlled by wet injection techniques. During the predominant combined cycle operation, a selective catalytic reduction (SCR) system with ammonia injection will be used in conjunction with dry low-NOx combustion (gas firing) and wet injection (oil firing) to further reduce NOx emissions. To meet peak power demands, the following alternate methods of operation will be authorized: high-temperature peaking (60 hours/year for simple cycle and 400 hours/year for combined cycle operation); steam injection for power augmentation (400 hours/year); and duct burning (2880 hours/year). During these restricted alternate methods of operation, NOx emissions are slightly higher. Emissions of CO, PM/PM_{10}, SAM, SO_2, and VOC will be minimized by the efficient, high-temperature combustion of very low sulfur fuels (natural gas and distillate oil). Emissions of CO and NOx will be continuously monitored to demonstrate compliance with the conditions of the permit. The Department determines that these control techniques and equipment represent the Best Available Control Technology (BACT) in accordance with Rule 62-212.400, F.A.C. and 40 CFR 52.21. Emissions standards are presented in the draft permit on file with the Department.

Based on the initial application, the maximum potential annual emissions from the combined cycle gas turbines, the gas fired-fuel heaters, and the cooling tower that comprise new Unit 8 are summarized in the following table. It is noted that some of the annual emissions estimates will be less because of lower standards specified in the DRAFT permit.

Pollutant	Maximum Tons Per Year	PSD Significant Emission Rate Tons Per Year	PSD Review Required?
CO	826	100	Yes
Pb	0.025	0.6	No
NOx	683	40	Yes
PM/PM_{10}	322/275	15/25	Yes
SO_2	280	40	Yes
SAM	30	7	Yes
VOC	110	40	Yes

According to the applicant, maximum predicted air quality impacts due to emissions from the proposed new project are less than the applicable PSD Class II significant impact levels, with the exception of 24-hour SO_2 impacts. Therefore, multi-source modeling was only required for the 24-hour SO_2 impacts. The predicted impacts in the Everglades National Park are less than the applicable PSD Class I significant impact levels except for the 24-hour SO_2 impacts; therefore, multi-source Class I PSD increment modeling was only required for the 24-hour SO_2 impacts. The following table summarizes the maximum predicted PSD Class I and II 24-hour SO_2 increment consumed by the new project and by all increment-consuming sources.

Area and Averaging Time	Increment Consumed Project/All Sources (SO_2, $\mu g/m^3$)	Allowable Increment All Sources (SO_2, $\mu g/m^3$)	Increment Consumed Project/All Sources (Percent)
Class I, 24-hour (Everglades National Park)	0.4/3.5	5	8/70
Class II, 24-hour (Vicinity of Plant)	9/41	91	10/45

Based on the required analyses, the Department has reasonable assurance that the proposed project will not cause or significantly contribute to a violation of any ambient air quality standard or PSD increment. The Department will issue the FINAL Permit, in accordance with the conditions of the DRAFT Permit, unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments and requests for a public meeting concerning the proposed permit issuance action for a period of 30 (thirty) days from the date of publication of this Public Notice of Intent to Issue PSD Permit. Written comments or requests for public meetings should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below. This PSD permitting action is being coordinated with a certification under the Power Plant Siting Act (Sections 403.501-519, F.S.). If a petition for an administrative hearing on the Department's Intent to Issue is filed by a substantially affected person, that hearing shall be consolidated with the certification hearing, as provided under Section 403.507(3). Mediation is not available in this proceeding.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code.

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C. Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

A complete project file is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at:

Department of Environmental Protection Bureau of Air Regulation 111 S. Magnolia Drive, Suite 4 (Mailing Address: 2600 Blair Stone Road, MS #5505) Tallahassee, Florida 32399-2400 Telephone: 850/488-0114 Fax: 850/922-6979

Department of Environmental Protection Southeast District Office 400 North Congress Avenue (Mailing Address: P.O. Box 15425) West Palm Beach, FL 33416-5425 Telephone: 561/681-6600 Fax: 561/681-6790

The complete project file includes the application, technical evaluations, Draft Permit, and the information submitted by the authorized representative, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Manager of the New Resource Review Section at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114 for additional information. The draft permit, technical evaluation and preliminary BACT determination can be accessed at www.dep.state.fl.us/air/permitting/construct.htm.

SCRIPPS HOWARD

SCRIPPS TREASURE COAST PUBLISHING COMPANY

The Stuart News
The Port St. Lucie News

1939 S. Federal Highway, Stuart, FL 34994

RECEIVED
SEP 27 2002
BUREAU OF AIR REGULATION

AFFIDAVIT OF PUBLICATION

STATE OF FLORIDA
COUNTY OF MARTIN; COUNTY OF ST. LUCIE

Before the undersigned authority personally appeared, S. Darlene Mailing, who on oath says that she is Classified Inside Sales Manager of the Stuart News and the Port St. Lucie News, a daily newspaper published at Stuart in Martin County, Florida: that the attached copy of advertisement was published in the Stuart/Port St. Lucie News in the following issues below. Affiant further says that the said Stuart/Port St. Lucie News is a newspaper published in Stuart in said Martin County, Florida, with offices and paid circulation in Martin County and St. Lucie County, Florida, and that said newspapers have heretofore been continuously published in said Martin County, Florida, daily and distributed in Martin and St. Lucie County, Florida, for a period of one year next preceding the first publication of the attached copy of advertisement; and affiant further says that she has neither paid nor promised any person, firm or corporation any discount, rebate, commission or refund for the purpose of securing this advertisement for publication in the said newspaper. The Stuart News has been entered as second class matter at the Post Offices in Stuart, Martin County, Florida and Ft. Pierce, St. Lucie County, Florida and has been for a period of one year next preceding the first publication of the attached copy of advertisement.

Ad #	Customer Name	Pub Date	Copyline	PO #
2515577	HOPPING GREEN & SAMS	09/12/2002	PSD PERMIT/FPL	

Subscribed and sworn to me before this date:

09/12/2002

S. Darlene Mailing

Mary T. Byrne
Notary Public

MARY T. BYRNE
Notary Public - State of Florida
My Commission Expires Aug 2, 2006
Commmission # DD132804
Bonded By National Notary Assn.

PUBLIC NOTICE OF INTENT TO ISSUE PSD PERMIT
STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
Draft Permit No. PSD-FL-327
FPL Martin Power Plant, New Combined Cycle Unit 8
Martin County

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The applicant proposes to construct a "4-on-1" combined cycle Unit 8 consisting of the following equipment and specifications: two existing 170 MW simple cycle gas turbine-electrical generator sets (8A and 8B), two new 170 MW gas turbine-electrical generator sets (8C and 8D), four gas-fired heat recovery steam generators (495 MMBtu/hour, LHV), a common steam-electrical generator (470 MW), two new gas-fired fuel heaters (22 MMBtu/hour, each), a cooling tower, and other associated support equipment. The gas turbines will be fired primarily with natural gas and up to 500 hours per year of very low sulfur distillate oil as a restricted alternate fuel. For the first year of operation, each gas turbine may operate in simple cycle mode for 3390 hours per year while the combined cycle components are constructed. Once combined cycle operation is established, simple cycle operation is limited to an average of 1000 hours per year. Additional equipment includes four 120-foot stacks combined cycle stacks, four 80-foot simple cycle stacks, and an aqueous ammonia storage tank.

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Based on the initial application, the maximum potential annual emissions from the combined cycle gas turbines, the gas fired-fuel heaters, and the cooling tower that comprise new Unit 8 are summarized in the following table. It is noted that some of the annual emissions estimates will be less because of lower standards specified in the DRAFT permit.

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NOx	683	40	Yes
PM/PM10	322/275	15/25	Yes
SO2	280	40	Yes
SAM	30	7	Yes
VOC	110	40	Yes

According to the applicant, maximum predicted air quality impacts due to emissions from the proposed new project are less than the applicable PSD Class II significant impact levels, with the exception of 24-hour SO2 impacts. Therefore, multi-source modeling was only required for the 24-hour SO2 impacts. The predicted impacts in the Everglades National Park are less than the applicable PSD Class I significant impact levels except for the 24-hour SO2 impacts; therefore, multi-source Class I PSD increment modeling was only required for the 24-hour SO2 impacts. The following table summarizes the maximum predicted PSD Class I and II 24-hour SO2 increment consumed by the new project and by all increment-consuming sources.

Area and Averaging Time	Increment Consumed Project/All Sources (SO2, ug/m3)	Allowable Increment All Sources (SO2, ug/m3)	Increment Consumed Project/All Sources (Percent)
Class I, 24-hour (Everglades National Park)	0.4/3.5	5	8/70
Class II, 24-hour (Vicinity of Plant)	9/41	91	10/45

Based on the required analyses, the Department has reasonable assurance that the proposed project will not cause or significantly contribute to a violation of any ambient air quality standard or PSD increment. The Department will issue the FINAL Permit, in accordance with the conditions of the DRAFT Permit, unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments and requests for a public meeting concerning the proposed permit issuance action for a period of 30 (thirty) days from the date of publication of this Public Notice of Intent to Issue PSD Permit. Written comments or requests for public meetings should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below. This PSD permitting action is being coordinated with a certification under the Power Plant Siting Act (Sections 403.501-519, F.S.). If a petition for an administrative hearing on the Department's Intent to Issue is filed by a substantially affected person, that hearing shall be consolidated with the certification hearing, as provided under Section 403.507(3). Mediation is not available in this proceeding.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code.

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.
A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C. Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.
A complete project file is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at:

Department of Environmental Protection
Bureau of Air Regulation
111 S. Magnolia Drive, Suite 4
(Mailing Address: 2600 Blair Stone Road, MS #5505)
Tallahassee, Florida 32399-2400
Telephone: 850/488-0114
Fax: 850/922-6979

Department of Environmental Protection
Southeast District Office
400 North Congress Avenue
(Mailing Address: P.O. Box 15425)
West Palm Beach, FL 33416-5425
Telephone: 561/681-6600
Fax: 561/681-6790

The complete project file includes the application, technical evaluations, Draft Permit, and the information submitted by the authorized representative, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Manager of the New Resource Review Section at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114 for additional information. The draft permit, technical evaluation and preliminary BACT determination can be accessed at www.dep.state.fl.us/air/permitting/construct.htm.
Publish: September 12, 2002 2515577

Golder Associates Inc.

6241 NW 23rd Street, Suite 500
Gainesville, FL 32653-1500
Telephone (352) 336-5600
Fax (352) 336-6603

Golder Associates

RECEIVED

AUG 20 2002

BUREAU OF AIR REGULATION

August 19, 2002

0137609

Mr. C. H. Fancy, P.E., Chief
Bureau of Air Regulation
Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399

RE: FPL MARTIN EXPANSION PROJECT
Comments to Draft Permit
Project No. 085001-010-AC (PSD-FL-327)

Attention: Mr. A.A. Linero, P.E., Administrator, New Source Review Section

Dear Al:

On behalf of Mr. John Lindsay of Florida Power & Light Company, I am submitting comments to the July 30, 2002 draft Air Permit and Prevention of Significant Deterioration (PSD) Permit for the FPL Manatee Expansion Project. The comments to the draft permit have been included directly on an electronic version of the permit. The comments included suggested changes to permit conditions as well as specific comments related to the reasons for the suggested change. If some of these changes are acceptable to the Department, there will also be some minor changes to the Public Notice and BACT determination.

As we discussed on August 8, 2002, most of the comments are self-explanatory and provide clarifications of the draft permit. There are several areas, summarized below, where changes are required to allow the Project to meet both performance and environmental goals.

- Duct Firing – A limit on the hours of operation for duct firing (i.e., 2,880) will not provide the operational flexibility for the Project as was requested in the original permit application. An annual heat input limit based on the maximum permitted heat input to the duct burners (550 MMBtu/hr) and a hypothetical number of hours (2,880) at that heat input rate was originally requested. The maximum heat input to the duct burners provided a worst case emission rate for modeling and the number of hours enveloped the amount of duct firing based on heat input. With an annual heat input limit, the annual emissions proposed for the project will not change regardless of the number of hours of duct firing.
- CO Emission Limit for Combined Cycle Operation – Based on our discussions on August 8, a 24-hour block CO emission limit of 10 ppmvd corrected to 15 percent oxygen is proposed for all modes of operation. This proposed limit is slightly higher than that proposed by the Department in the draft permit for baseload operation and duct firing, but lower than that proposed for peak and power augmentation. This limit will provide the operational flexibility regardless of the mode of operation and will be much easier to track for compliance purposes. Having two separate 24-hour block average CO limits for different combined cycle modes will confound the determination of compliance. Also, the proposed limit is 40 to 50 percent

lower than that approved by the Department for recent projects licensed under Florida's Power Plant Siting Act.

- Startup/Shutdown – Three specific conditions have been suggested to handle the unique startup conditions for a 4 on 1 project. The conditions are similar to those authorized for the Fort Myers and Sanford Repowering Projects. These suggested conditions would ensure reliability of equipment and minimize the periods of excess emissions. Information concerning the cold startup for the heat recovery steam generator was provided on August 8. Please find attached information as requested on August 8, concerning the cold startup of the steam turbine. The information provided demonstrates that the necessity of the suggested conditions.

Also, it is suggested that the appendices for 40 CFR Subpart Da and GG to the permit be the same for both the Manatee and Martin Expansion Projects. The appendices included with the Martin formed the basis of the suggested comments. Attached are the appendices including the suggested changes. Please note that if natural gas fired fuel gas heaters are constructed, they will be direct fired as included in the application and 40 CFR Part Dc would not apply. This appendix should be deleted.

Please contact either Mr. Simmons, the FPL application contact [phone (561) 691-2216], or myself if there are any questions. We will contact the Department in a few days to review our suggested draft permit changes.

Sincerely,

GOLDER ASSOCIATES INC.

Kennard F. Kosky

Kennard F. Kosky, P.E.
Principal

KFK/arz

Enclosures

cc: John M. Lindsay, Plant General Manager Martin Plant w/enclosures
K. H Simmons, Manager of New Capacity Projects w/enclosures
Mr. Jeffery F. Koerner, P.E. DEP New Source Review Section w/enclosures
J. Little, SED

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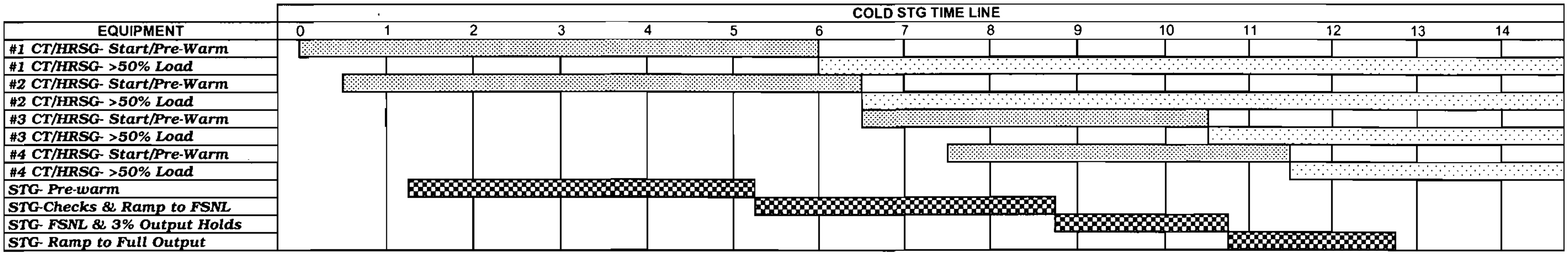
B. Worley, EPA
J. Bunyak, NPS
C. Holladay
B. Oven

ESTIMATED START-UP TIMELINE FOR COLD STEAM TURBINE GENERATOR
MARTIN and MANATEE EXPANSION PROJECTS



Notes:

Per Toshiba Extrapolated Start-Up Curve for the Forney Project (Similar STG)
STG requires 4 1/2 hour warmup prior to roll, 3 1/2 hours to FSNL, 2 hours of holds, and 2 hours to ramp to full output.
HRSG requires 90 minute ramp to hold pressure, 60 minute drum soak, and 60 minutes to ramp to full steam bypass operation.

DRAFT PERMIT

PERMITTEE:

Florida Power and Light Company
P.O. Box 176
Indiantown, FL 34956

Authorized Representative:
John M. Lindsay, Plant General Manager

FPL Martin Power Plant
Project No. 0850001-010-AC
Air Permit No. PSD-FL-327
SIC No. 4911
Expires: December 30, 2006~~5~~

[Comment: An expiration date of December 2006 is requested, since the project is being licensed within Florida's site certification process.]

PROJECT AND LOCATION

This permit authorizes the construction of Unit 8, a nominal 1150-megawatt "4-on-1" combined cycle unit at the existing Martin Power Plant. The project will utilize two existing 170 MW gas turbine-electrical generator sets and will add two new 170 MW gas turbine-electrical generator sets, four new heat recovery steam generators, a single nominal 470 MW steam turbine-electrical generator, gas-fired fuel heaters, and a mechanical draft cooling tower. The existing Martin Power Plant is located approximately 7 miles north of Indiantown on State Road 710 in Martin County, Florida.

STATEMENT OF BASIS

This PSD air pollution construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.) and Title 40, Part 52, Section 21 of the Code of Federal Regulations. Pursuant to Chapter 62-17, F.A.C. and Chapter 403 Part II, F.S., the project is also subject to Electrical Power Plant Siting and was therefore processed in accordance with Florida's delegated program for the Prevention of Significant Deterioration (PSD) of Air Quality. The permittee is authorized to install the proposed equipment 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.

CONTENTS

(DRAFT)

Howard L. Rhodes, Director
Division of Air Resources Management

(Date)

FACILITY DESCRIPTION

The existing Martin Power Plant currently consists of six electrical generating units. Fossil fuel-fired steam electric generators Units 1 and 2 (863 MW nominal each) began operation in 1980 and 1981, respectively. Combined cycle gas turbine Units 3A/3B and 4A/4B (430 MW nominal each) began operation in 1994. Existing simple cycle gas turbine Units 8A and 8B (170 MW nominal each) began operation in 2001. Units 8A and 8 B will be incorporated into the new "4 on 1" combined cycle Unit 8, which will consist of two new gas turbine Units 8C and 8D (170 MW nominal each), four heat recovery steam generators, a single steam turbine-electrical generator (470 nominal MW), and a mechanical draft cooling tower. Unit 8 will have a total nominal generating capacity of 1150 MW. After completion of this project, the plant will have a nominal generating capacity of 3610 MW. [Comment: The use of "nominal" when discussion capacity is preferred as actual capacity varies based on operating conditions.]

NEW AND MODIFIED EMISSIONS UNITS

This permit authorizes construction and installation of the following new emissions units.

ID	Emission Unit Description
011	Unit 8A gas turbine (170 MW nominal) with heat recovery steam generator
012	Unit 8B gas turbine (170 MW nominal) with heat recovery steam generator
013	Gas-fired fuel heaters (two)
017	Unit 8C gas turbine (170 MW nominal) with heat recovery steam generator
018	Unit 8D gas turbine (170 MW nominal) with heat recovery steam generator
019	Mechanical draft cooling tower for Unit 8

Note: Martin Unit 8 consists of four gas turbine-electrical generator sets (Units 8A-8D), four gas-fired heat recovery steam generators (HRSGs), and a single steam-turbine electrical generator.

REGULATORY CLASSIFICATION

Title III: The existing facility is major for hazardous air pollutants (HAPs). This project is not major for HAPs.

Title IV: The facility operates emissions units subject to the acid rain provisions of the Clean Air Act.

Title V: Because potential emissions of at least one regulated pollutant exceed 100 tons per year, the existing facility is a Title V major source of air pollution in accordance with Chapter 62-213, F.A.C. Regulated pollutants include pollutants such as carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), and volatile organic compounds (VOC).

PSD: The project is located in an area designated as "attainment" or "unclassifiable" for each pollutant subject to a National Ambient Air Quality Standard. The facility is considered a "fossil fuel fired steam electric plant of more than 250 million BTU per hour of heat input", which is one of the 28 PSD source categories with the lower PSD applicability threshold of 100 tons per year. Potential emissions of at least one regulated pollutant exceed 100 tons per year. Therefore, the facility is classified as a PSD-major source of air pollution with respect to Rule 62-212.400, F.A.C, the Prevention of Significant Deterioration (PSD) of Air Quality.

NSPS: The following New Source Performance Standards (NSPS) apply to this project: 40 CFR 60, Subpart Da (gas-fired duct burners); ~~40 CFR 60, Subpart Dc (gas fired fuel heaters);~~ and 40 CFR 60, Subpart GG (gas turbines). [Comment: Direct fired fuel gas heaters are not subject to Subpart Dc since these type units do not meet the definition of "steam generating unit in Section 60.41c (i.e., produces steam or heat water or any other heat transfer medium).]

NESHAP: No emissions units are identified as subject to any National Emissions Standards for Hazardous Air Pollutants (NESHAP).

Siting: The project is subject to Electrical Power Plant Siting in accordance with Chapter 62-17, F.A.C. and Chapter 403, Part II, F.S.

PERMITTING AUTHORITY

All documents related to applications for permits to construct, operate or modify an emissions unit shall be submitted to the Bureau of Air Regulation of the Florida Department of Environmental Protection (DEP) at 2600 Blair Stone Road (MS #5505), Tallahassee, Florida 32399-2400. Copies of all such documents shall also be submitted to the Compliance Authority.

COMPLIANCE AUTHORITY

All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Air Resources Section of the Southeast District Office, Florida Department of Environmental Protection, Post Office Box 15425, West Palm Beach, Florida 33416-5425.

APPENDICES

The following Appendices are attached as part of this permit.

- Appendix A. Citation Format and Definitions
- Appendix BD. Final BACT Determinations and Emissions Standards
- Appendix Da. NSPS Subpart Da Requirements for Gas-Fired Duct Burners
- Appendix Dc. NSPS Subpart Dc Requirements for Gas-Fired Fuel Heaters
- Appendix GC. Construction Permit General Conditions
- Appendix GG. NSPS Subpart GG Requirements for Gas Turbines
- Appendix SC. Standard Conditions

RELEVANT DOCUMENTS

The documents listed below are not a part of this permit; however, they are specifically related to this permitting action and are on file with the Department.

- Permit application received on 02/01/02 and all related completeness correspondence.
- Draft permit package issued on (Draft).
- Comments received from the public, the applicant, the EPA Region 4 Office, and the National Park Service.
- PSD Permit No. PSD-FL-286

1. General Conditions: The permittee shall operate under the attached General Conditions listed in Appendix GC of this permit. General Conditions are binding and enforceable pursuant to Chapter 403 of the Florida Statutes. [Rule 62-4.160, F.A.C.]

2. Applicable Regulations, Forms and Application Procedures: Unless otherwise indicated in this permit, the construction and operation of the subject emissions unit shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of: Chapter 403 of the Florida Statutes (F.S.); Chapters 62-4, 62-204, 62-210, 62-212, 62-213, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.); and the Title 40, Parts 51, 52, 60, 72, 73, and 75 of the Code of Federal Regulations (CFR), adopted by reference in Rule 62-204.800, F.A.C. The terms used in this permit have specific meanings as defined in the applicable chapters of the Florida Administrative Code. 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. Issuance of this permit does not relieve the permittee from compliance with any applicable federal, state, or local permitting or regulations. [Rules 62-204.800, 62-210.300 and 62-210.900, F.A.C.]

3. Construction and Expiration: The permit expiration date includes sufficient time to complete construction, perform required testing, submit test reports, and submit an application for a Title V operation permit to the Department. Approval to construct shall become invalid for any of the following reasons: construction is not commenced within 18 months after issuance of this permit; construction is discontinued for a period of 18 months or more; or 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. In conjunction with an extension of the 18-month period to commence or continue construction, or phasing of the project, ~~or an extension of the permit expiration date,~~ the Department may require the permittee to demonstrate the adequacy of any previous determination of Best Available Control Technology (BACT) for emissions units regulated by the project. For good cause, the permittee may request that this PSD air construction permit be extended. Such a request shall be submitted to the Department's Bureau of Air Regulation at least sixty (60) days prior to the expiration of this permit. [Rules 62-4.070(4), 62-4.080, 62-210.300(1), and 62-212.400(6)(b), F.A.C.; 40 CFR 52.21(r)(2); 40 CFR 51.166(j)(4)](Comment: Suggested change consistent with FDEP rules.]

4. New or Additional Conditions: 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.]

5. Modifications: No emissions unit or facility subject to this permit shall be constructed or modified without obtaining an air construction permit from the Department. Such permit shall be obtained prior to beginning construction or modification. [Chapters 62-210 and 62-212, F.A.C.]

6. Application for Title IV Permit: At least 24 months before the date on which the new unit begins serving an electrical generator greater than 25 MW, the permittee shall submit an application for a Title IV Acid Rain Permit to the Department's Bureau of Air Regulation in Tallahassee and a copy to the Region 4 Office of the U.S. Environmental Protection Agency in Atlanta, Georgia. [40 CFR 72]

7. Title V Permit: This permit authorizes construction of the permitted emissions units and initial operation to determine compliance with Department rules. A Title V operation permit is required for regular operation of the permitted emissions unit. The permittee shall apply for a Title V operation permit at least 90 days prior to expiration of this permit, but no later than 180 days after commencing operation. To apply for a Title V operation permit, the applicant shall submit the appropriate application form, compliance test results, and such additional information as the Department may by law require. The application shall be

submitted to the Department's Bureau of Air Regulation with a copy to the Compliance Authority. [Rules 62-4.030, 62-4.050, 62-4.220, and Chapter 62-213, F.A.C.]

A. UNIT 8 – "4 ON 1" COMBINED CYCLE GAS TURBINE

This section of the permit addresses the following emissions units.

Emissions Units 011, 012, 017, 018

Description: Emissions units 011, 012, 017, and 018 each consist of a General Electric Model PG7241(FA) gas turbine-electrical generator set, an automated gas turbine control system, an inlet air filtration system, an evaporative inlet air-cooling system, a gas-fired heat recovery steam generator (HRSG), a bypass stack, a HRSG stack, and associated support equipment. In addition, the project also includes a single steam turbine-electrical generator that serves all four gas turbine/HRSG systems. Units 011 and 012 are subject to Permit No. PSD-FL-286, rather than this permit, until commencement of steam blows for conversion to combined cycle.[Comment: In some permit conditions a distinction between the existing the "new" gas turbines have been made.]

Fuels: Each gas turbine fires natural gas as the primary fuel and distillate oil as a restricted alternate fuel.

Generating Capacity: Each of the four gas turbine-electrical generator sets has a nominal generating capacity of 170 MW for gas firing (180 MW nominal for oil firing). Exhaust from each gas turbine passes through a separate heat recovery steam generator (HRSG). Steam from each HRSG is delivered to the single steam turbine-electrical generator, which has a nominal capacity of 470 MW. The total nominal generating capacity of the "4 on 1" combined cycle unit is 1150 MW.

Controls: The efficient combustion of natural gas and restricted firing of low sulfur distillate oil minimizes the emissions of CO, PM/PM_{10}, SAM, SO_2 and VOC. Dry low-NOx (DLN) combustion technology for gas firing and water injection for oil firing reduce NOx emissions during simple cycle operation. A selective catalytic reduction (SCR) system in combination with the other NOx controls further reduces NOx emissions during combined cycle operation.

Stack Parameters: Each gas turbine has a bypass stack (80 feet tall and 22.0 feet in diameter) and each heat recovery steam generator has a HRSG stack (120 feet tall and 19.0 feet in diameter). The following summarizes the exhaust characteristics:

Fuel

Heat Input Rate

Compressor
Inlet Temp.

Simple Cycle Operation

Combined Cycle Operation

Exhaust Temp.

Flow Rate
ACFM

Exhaust
Temp., °F

Flow Rate

ACFM

Gas

1600 MMBtu/hour

59° F

1116° F

2,389,500

202° F

1,004,200

Oil

1811 MMBtu/hour

59° F

1098° F

2,735,300

295° F

1,193,900

Continuous Monitors: Each stack is equipped with continuous emissions monitoring systems (CEMS) to measure and record CO and NOx emissions as well as flue gas oxygen or carbon dioxide content.

APPLICABLE STANDARDS AND REGULATIONS

1. BACT Determinations: Determinations of the Best Available Control Technology (BACT) were made for carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM_{10}), sulfuric acid mist (SAM), and sulfur dioxide (SO_2), and volatile organic compounds (VOC). See Appendix BD of this permit for a summary of the final BACT determinations. [Rule 62-212.400(BACT), F.A.C.]

2. NSPS Requirements: The Department determines that compliance with the BACT emissions performance and monitoring requirements also assures compliance with the New Source Performance Standards for Subpart Da (duct burners) and Subpart GG (gas turbines) in 40 CFR 60. For completeness, the applicable Subpart GG and Subpart Da requirements are summarized in Appendices Dae and GG of this permit. [Rule 62-204.800(7), F.A.C.]

EQUIPMENT

3. Gas Turbine Units 8C and 8D: The permittee is authorized to install, tune, operate, and maintain two new General Electric Model PG7241FA gas turbine-electrical generator sets each with a nominal capacity of 170 MW (EU 017 and 018). Each gas turbine shall include the Speedtronic™ automated gas turbine control system and have dual-fuel capability. Ancillary equipment includes an inlet air filtration system, an evaporative inlet air-cooling system, and a bypass stack for simple cycle operation~~ that is 80 feet tall and 22.0 feet in diameter.~~ The gas turbines will utilize the "hot nozzle" DLN combustors, which require natural gas to be preheated to approximately 290° F before combustion to increase overall unit efficiency. Gas-fired fuel heaters (EU 013) will preheat the natural gas during simple cycle operation and during startup to combined cycle operation. For full combined cycle operation, feedwater heat exchangers will preheat the natural gas. *{Permitting Note: Two existing simple cycle General Electric Model PG7241FA gas turbine-electrical generator sets, Units 8A and 8B (EU 011 and 012), will be incorporated into the "4-on-1" combined cycle Unit 8.}* [Application; Design] [Comments: Stack parameters should not be included as a condition of the permit and to FPL's knowledge has not been included as specific conditions in previous permits. During design, the stack diameter and height may be changed to meet specific needs. The stack parameters provided in the application generally represent worst case dispersion conditions and if any changes occur, FPL would provide additional modeling if requested by the Department.]

4. Gas Turbine NOx Controls

   a. *DLN Combustion*: The permittee shall operate and maintain the General Electric DLN 2.6 combustion system (or better) to control NOx emissions from each gas turbine when firing natural gas. Prior to the initial emissions performance tests required for each new gas turbine, the DLN combustors and automated gas turbine control system shall be tuned to meet the~~reduce~~ NOx~~ emissions below~~ permitted levels. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations. [Comment: The DLN-2.6 combustion system will be constructed and operated pursuant to GE specifications, which provide guaranteed emission levels for NO_x when firing gas. FPL has no contractual basis to request GE to deviate from the contract in attempting to achieve lower NO_x levels than the contract. Moreover, any attempt to lower contract NO_x levels below the contract levels could affect emissions of other air pollutants (e.g., CO and VOC).]

   b. *Water Injection*: The permittee shall install, operate, and maintain a water injection system to reduce NOx emissions from each gas turbine when firing distillate oil. Prior to the initial emissions performance tests required for new each gas turbine, the water injection system shall be tuned to meet the~~reduce~~ NOx~~ emissions below~~ permitted levels. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations. The automated control system shall be programmed to establish a water-to-fuel ratio designed to meet the NOx emission standard on a 1-hour basis. [Comment: The DLN-2.6 combustion system will be constructed and operated pursuant to GE specifications, which provide guaranteed emission levels for NO_x when firing oil. FPL has no contractual basis to request GE to deviate from the contract in attempting to achieve lower NO_x levels than the contract. Moreover, any attempt to lower contract NO_x levels below the contract levels could affect emissions of other air pollutants (e.g., CO and VOC).]

   c. *(SCR) System*: The permittee shall install, tune, operate, and maintain a selective catalytic reduction (SCR) system to control NOx emissions from each gas turbine during combined cycle operation when firing either natural gas or distillate oil. The SCR system consists of an ammonia injection grid, catalyst, aqueous ammonia storage, monitoring and control system, electrical, piping and other ancillary equipment. The SCR system shall be designed and operated to meet the~~reduce~~ NOx emissions and ammonia slip~~ below the~~ permitted levels. *{Permitting Note: The ammonia tank will store~~ aqueous~~*

ammonia. ~~*having a concentration of less than 20 percent ammonia.*~~ *In accordance with 40 CFR 60.130,* ~~*it is not*~~*the storage of ammonia may be subject to the Chemical Accident Prevention Provisions of 40 CFR 68.}* [Comments: Both aqueous and anhydrous ammonia may be used for the SCR system. The SCR system will be designed, constructed and operated to meet the emission levels specified in the permit for NO_x and ammonia slip. FPL will obtain contractual guarantees to meet these permitted emission levels. It is expected that the SCR manufacturer would include operating margin in the design. However, the term "below" as proposed in the draft permit must be removed since it is unknown what "below" means.

[Design; Rule 62-212.400(BACT), F.A.C.]

5. HRSGs: The permittee is authorized to install, operate, and maintain four new heat recovery steam generators (HRSGs). Each HRSG shall be designed to recover heat energy from one of the four gas turbines (8A-8D) and deliver steam to the steam turbine electrical generator through a common manifold. ~~Each HRSG shall include an exhaust stack that is 120 feet tall and 19.0 feet in diameter. To minimize the number of cold startups to combined cycle operation, each HRSG system shall include a damper in the ductwork before the stack to reduce heat loss during shutdowns.~~ Each HRSG may be equipped with supplemental gas-fired duct burners having a maximum heat input rate of 495 MMBtu per hour (LHV). *{Permitting Note: The four HRSGs deliver steam to a single steam turbine-electrical generator with a nominal capacity of 470 MW.}* [Application; Design] [Comments: Stack parameters should not be included as a condition of the permit and to FPL's knowledge has not been included as specific conditions in previous permits. During design, the stack diameter and height may be changed to meet specific needs. The stack parameters provided in the application generally represent worst case dispersion conditions and if any changes occur, FPL would provide additional modeling if requested by the Department. Each HRSG will not be installed with a stack damper, since the Project is being designed as a baseload unit operated within the FPL system. As a result, the unit will be high on the dispatch order due to its efficiency and cycling the unit is not expected to occur. Martin Unit 8, as a baseloaded unit, will not be cycled like smaller independent power units (e.g., 1 on 1 or 2 on 1 configurations) used to meet peak power sales. As a result, the period of cold startups will primarily be associated with maintenance or malfunctions that require rapid cool-down and often downtimes in excess of 48 hours. Stack dampers will not provide any benefit in reducing heat loss from the HRSG for these maintenance and repair periods.]

PERFORMANCE RESTRICTIONS

6. Permitted Capacity - Gas Turbines: The heat input rate to each gas turbine is~~shall not exceed~~ 1600 MMBtu per hour when firing natural gas and 1811 MMBtu per hour when firing distillate oil (based on a compressor inlet air temperature of 59° F, the lower heating value (LHV) of each fuel, and 100% load). Heat input rates will vary depending upon gas turbine characteristics, ambient conditions, alternate methods of operation, and evaporative cooling. The permittee shall provide manufacturer's performance curves (or equations) that correct for site conditions to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department. [Rule 62-210.200(PTE), F.A.C.] *{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 100 percent of the test load), to establish appropriate limits and to aid in determining future rule applicability. Regular record keeping, except for 40 CFR Part 75, 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 rated capacity that the unit is tested.."}* [Comment: The heat input is specific to the conditions noted

and not "normal conditions" in the overall operation of the gas turbine. The permitting note should be added to clarify the use of heat input as permit condition. This is the same permitting note in the recent JEA Brandy Branch PSD Permit.]

7. Permitted Capacity - HRSG Duct Burners: The maximum~~total~~ heat input rate to the duct burners for each HRSG is~~shall not exceed~~ 495 MMBtu per hour based on the lower heating value (LHV) of natural gas. Only natural gas shall be fired in the duct burners. [Rule 62-210.200(PTE), F.A.C.] *{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 100 percent of the test load), to establish appropriate limits and to aid in determining future rule applicability. Regular record keeping, except for 40 CFR Part 75, 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 rated capacity that the unit is tested.."}*. [Comment: The permitting note should be added to clarify the use of heat input as permit condition.]

8. Methods of Operation: Subject to the restrictions and requirements of this permit, the gas turbines may operate under the following methods of operation.

   a. *Hours of Operation*: Subject to the operational restrictions of this permit, the gas turbines may operate throughout the year (8760 hours per year). Restrictions on individual methods of operation are specified below.

   b. *Authorized Fuels*: Each gas turbine shall fire natural gas as the primary fuel, which shall contain no more than 2.0 grains of sulfur per 100 standard cubic feet of natural gas. As a restricted alternate fuel, each gas turbine may fire No. 2 distillate oil (or a superior grade) containing no more than 0.05% sulfur by weight. Each gas turbine shall fire no more than 500 hours of distillate oil during any consecutive 12 months.

   c. *Simple Cycle Operation*: Each new gas turbine may operate individually in simple cycle mode to produce only direct, shaft-driven electrical power subject to the following operational restrictions.

      (1) Each gas turbine shall operate in simple cycle mode for no more than 3390 hours during any consecutive 12 months.

      (2) After demonstrating initial compliance in combined cycle mode, the combined group of four gas turbines shall operate in simple cycle mode for no more than an average of 1000 hours during any consecutive 12 months.

   d. *Combined Cycle Operation*: Each gas turbine/HRSG system may operate to produce direct, shaft-driven electrical power and deliver steam to the steam turbine-electrical generator to produce steam-generated electrical power as a four-on-one combined cycle unit subject to the restrictions of this permit. In accordance with the manufacturer's specifications, the SCR system shall be on line and functioning properly during combined cycle operation~~.~~ with the exception of startups, shutdowns or malfunctions as provided for in Specific Condition 16 or DLN tuning as provided for in Specific Condition 18. *{Permitting Note: Combined cycle as termed in this permit means the production of steam in the HRSG.}* [Comment: Inclusion of allowable excess emissions clarifies the intent of this condition. Also, if there is a steam turbine malfunction, steam could still be produced in the HRSG and diverted to the condenser. As an alternative, a specific condition similar to the Martin draft permit could be added.]

   e. *Inlet Fogging*: In accordance with the manufacturer's recommendations and appropriate ambient conditions, the evaporative cooling system may be operated to reduce the compressor inlet air temperature and provide additional direct, shaft-driven electrical power. This method of operation is commonly referred to as "fogging" and may be used in either simple cycle or combined cycle modes.

f. *Peaking*: When firing natural gas, each gas turbine may operate in a high-temperature peaking mode to generate additional direct, shaft-driven electrical power to respond to peak demands. During any consecutive 12 months, each gas turbine shall operate while in the peaking mode for no more than 60 hours of simple cycle operation and no more than 400 hours of combined cycle operation.

g. *Power Augmentation*: When firing natural gas in either simple cycle or combined cycle modes, steam may be injected into each gas turbine to generate additional direct, shaft-driven electrical power to respond to peak demands. To qualify as "power augmentation", the combustion turbine must operate at a load of 95% or greater than that of the manufacturer's maximum base load rate adjusted for the compressor inlet air conditions. Prior to activating and after deactivating the power augmentation mode, the operator shall log the date, time, and new mode of operation. Each gas turbine shall operate in the power augmentation mode for no more than 400 hours during any consecutive 12 months. The gas turbines shall not operate simultaneously in peaking and power augmentation modes. In addition, total combined operation of power augmentation and peaking modes shall not exceed 400 hours during any consecutive 12 months per unit.

h. *Combined Cycle Operation with Duct Firing*: When firing natural gas and operating in combined cycle mode, each gas turbine/HRSG system may fire natural gas in the duct burners to provide additional steam-generated electrical power. The heat input to the duct burners for all four~~Each~~ HRSGs shall not exceed 5,702,400 MMBtu~~fire the duct burners no more than 2880 hours~~ during any consecutive 12 months. . [Comment: The PSD permit application requested an equivalent heat input limit for duct firing based on the maximum heat input 495 MMBtu/hr for 2,880 hours per year. Duct firing will be variable depending on power needs and limiting hours would not provide the flexibility required to provide incremental power from Unit 8. Moreover, providing incremental power through duct firing on Unit 3 would reduce requirements of operating other units in FPL's system with concomitant benefits in reducing emissions from older less efficient and higher emitting units.]

[Application; Rules 62-210.200(PTE) and 62-212.400(BACT), F.A.C.]

EMISSIONS STANDARDS

9. Emissions Standards: Emissions from each gas turbine shall not exceed the following standards.

Pollutant	Fuel	Method of Operation	Initial[1]		CEMS (Block Average)
			ppmvd @ 15% O_2	lb/hour[2]	ppmvd @ 15% O_2
CO[a]	Oil	Simple or Combined Cycle	14.4, 3-hr	64.7	15.0, 24-hr
	Gas	Simple or Combined Cycle	7.4, 3-hr	27.5	8.0, 24-hr
		Combined Cycle w/DB, PA or PK	14.1~~7.4~~, 3-hr	71.5~~37.5~~	10~~8~~.0, 24-hr
		Simple ~~or Combined Cycle~~ w/PA	12.0, 3-hr	45.0	12.0, 24-hr
		~~Combined Cycle w/DB+PA~~	~~12.0, 3-hr~~	~~55.6~~	~~12.0, 24-hr~~
NOx[b]	Oil	Simple Cycle	42.0, 3-hr	319.2	42.0, 3-hr
		Combined Cycle – SCR	12~~0~~.0, 3-hr	91.2~~76.0~~	12~~0~~.0, 24-hr
	Gas	Simple Cycle	9.0, 3-hr	58.7	9.0, 24-hr
		Simple Cycle w/PA	NA	(76.2)	12.0, 3~~1~~-hr

		Simple Cycle w/Peaking	NA	(95.3~~101.3~~)	15.0, 3~~1~~-hr
		Combined Cycle – SCR	2.5, 3-hr	16.3	2.5, 24-hr
		Combined Cycle w/DB – SCR	2.5, 3-hr	23.2~~2.1~~	2.5, 24-hr
PM/PM10 [c]	Oil/Gas	Simple or Combined Cycle	Fuel Specifications		
		Simple or Combined Cycle	Visible emissions shall not exceed 10% opacity for each 6-minute average as determined by EPA Method 9 observations.		
SAM/SO2 [d]	Oil/Gas	Simple or Combined Cycle	Fuel Specifications		
VOC [e]	Oil	Simple or Combined Cycle	2.5, 3-hr	6.0	NA
	Gas	Simple or Combined Cycle	1.3, 3-hr	2.8	NA
		Combined Cycle, w/DB or PA	4.0, 3-hr	10.5~~9.2~~	NA
Ammonia [f]	Oil/Gas	Combined Cycle – SCR	9~~5~~.0, 3-hr	NA	NA

[1] Initial compliance tests are not required for Units 8A and 8B in simple cycle mode.

[2] Applicable for the initial compliance tests only; lb/hr values are at a turbine inlet of 59 degrees F and must be adjusted to actual testing conditions.

Note: "DB" means duct burning. "PA" means power augmentation.

[Comments: The heading "Block" should be added to clarify the averaging period. As discussed at the August 8, 2002 meeting, the column for lb/hr is applicable for initial testing only. A footnote was added to indicate the lb/hr values were included for initial testing only and that these are at compressor inlet temperature of 59 degrees F and must be adjusted. The lb/hr values for some conditions were corrected to the ISO condition. For the 24-hour block for CO, a limit of 10 ppmvd corrected to 15% O_2 for all combined cycle operating modes is proposed. This is a slight increase in the Department's proposed limit of 8 ppmvd corrected to 15% O_2 but lower for PA and PK modes. The 14.1 ppmvd corrected to 15% O_2 reflects the maximum CO emissions with duct firing at 495 MMBtu/hr (LHV). An averaging period of 1-hour for NO_x emissions in PA or PK modes is inappropriate and as a minimum difficult if not impossible to track through using a CEM system. A 3-hour averaging time is appropriate and consistent with the Department's testing requirements. The requirement for a NOx emission limit of 10 ppmvd will require considerable increased costs for the SCR system by the addition of catalyst. Fuel oil will be only used on a limited basis and such increased cost will have little environmental benefit. For VOCs, the 10.5 lb/hr is equivalent to 4 ppmvd corrected to 15% O_2 reflects the maximum CO with duct firing at 495 MMBtu/hr (LHV). An emission limit for ammonia slip of 9 ppmvd corrected to 15 percent oxygen is requested. The lower limit would unnecessarily require additional catalyst that is equivalent to that required for reducing NO_x emissions from 3.5 ppmvd corrected to 2.5 ppmvd corrected.]

a. Compliance with the initial 3-hour CO standards can~~shall~~ be demonstrated based on data collected by the required CEMS. Compliance may also be determined by EPA Method 10. Compliance with the 24-hour block CO standards shall be determined separately for simple cycle and combined cycle~~each method of~~ operation based on the hours of operation for each method. *{Permitting Note: A 24-hour compliance average may be based on as little as 1-hour of CEMS data or as much as 24-hours of CEMS data.}*[Comment: Language added to clarify condition.]

b. Compliance with the initial 3-hour NOx standards can~~shall~~ be demonstrated based on data collected by the required CEMS. Compliance may also be determined by EPA Method 7E or 20. NOx mass emission rates are defined as oxides of nitrogen expressed as NO_2. Compliance with the 24-hour block NOx standard shall be demonstrated based on data collected by the required CEMS. Compliance with the NOx standard for simple cycle operation with peaking or power augmentation shall be demonstrated on a~~n~~ 3-hour~~-to-hour~~ block average basis with CEMS data. CEMS data collected during simple cycle peaking or power augmentation shall be excluded from the data used to demonstrate compliance with the 24-hour standard for normal operation. *{Permitting Note: The "lb/hour" rates for simple cycle peaking or power augmentation are for informational purposes only.}*[Comment: Language added to clarify condition.]

c. The fuel specifications established in Condition No. 8~~8~~ of this section combined with the efficient combustion design and operation of each gas turbine represents the Best Available Control Technology (BACT) determination for PM/PM_{10} emissions. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion. *{Permitting Note: PM_{10} emissions for gas firing are estimated at 9 lb/hour for simple cycle operation, 11 lb/hour for combined cycle operation, and 17 lb/hour for combined cycle operation with duct burning. PM_{10} emissions for oil firing are estimated at 17 lb/hour for simple cycle operation and 37 lb/hour for combined cycle operation.}*

d. The fuel sulfur specifications in Condition No. 8~~8~~ of this section effectively limit the potential emissions of SAM and SO_2 from the gas turbines and represent the Best Available Control Technology (BACT) determination for these pollutants. Compliance with the fuel sulfur specifications shall be determined by the requirements in Condition No. 28~~28~~ of this section. *{Permitting Note: SO_2 emissions for gas firing are estimated at 9.8 lb/hour for simple and combined cycle operation and 12.8 lb/hour for combined cycle operation with duct burning. SO_2 emissions for oil firing are estimated at 99 lb/hour for simple and combined cycle operation. SAM emissions are estimated to be less than 10% of the SO_2 emissions.}*

e. Compliance with the VOC standards shall be demonstrated by conducting tests in accordance with EPA Method 25A. Optionally, EPA Method 18 may be also be performed to deduct emissions of methane and ethane. The emission standards are based on VOC measured as methane.

f. Not Federally Enforceable. Compliance with the ammonia slip standard shall be demonstrated by conducting tests in accordance with EPA Method CTC-027.

g. Initial compliance tests are not required for Units 8A and 8B in simple cycle mode.

[Rule 62-212.400(BACT), F.A.C.]

10. Combined Cycle Operation With~~-Dump~~ Condenser: If the steam-electrical turbine generator is off line, the permittee is authorized to operate the gas turbine/HRSG systems by transferring steam to a dump condenser. Operation with a~~-dump~~ condenser must still meet the standards established for combined cycle operation with ammonia injection. ~~*{Permitting Note: Although this method of operation is inefficient, it may be preferable due to the time necessary to shutdown, cool, and prepare the units for simple cycle operation.}*~~ [Application] [Comment: The condenser for the steam turbine will have the ability to dump steam. A separate condenser dump condenser would not be required. Permitting note should be deleted as it is inappropriate and implies that the Department has authority in approving the efficiency of Projects.]

11. Duct Burners: The duct burners are also subject to the provisions of Subpart Da of the New Source Performance Standards in 40 CFR 60, which are summarized in Appendix Da. [Subpart Da, 40 CFR 60]]*{Permitting Note: Compliance with the combined cycle emission limit of 2.5 ppmvd corrected to 15*

percent oxygen is more stringent than the NSPS limit of 1.6 lb/MW-hr. The use of natural gas with a sulfur content of 2 grains/100 scf will produce emission rates more stringent than the NSPS limits of 0.03 lb/MMBtu and 0.2 lb/MMBtu for PM and SO_2, respectively. Demonstrating compliance with the NO_x emission limit for combined cycle operation will demonstrate compliance with the NSPS emission limit.][Comment: The added permitting note would clarify that meeting the BACT limit would meet the NSPS limit for Subpart Da.]

PROJECT PHASE-IN

12. Existing Simple Cycle Units: For existing Units 8A and 8B (EU 011 and 012), PSD-FL-286 shall remain in full force and effect. ~~t~~This PSD permit shall not apply unitl initial steam blows. Upon commencement of the initial steam blows for Units 8A and 8B, this permit shall replace and supersede previously issued PSD permit (No. PSD-FL-286) for these tow units. ~~upon commencement of the initial steam blows.~~PSD Permit No. PSD-FL-286 will continue to be in effect for the existing gas heaters and oil tank. [Rule 62-4.070(3), F.A.C.]

EXCESS EMISSIONS

13. Operating Procedures: The Best Available Control Technology (BACT) determinations established by this permit rely on "good operating practices" to reduce emissions. Therefore, all operators and supervisors shall be properly trained to operate and maintain the gas turbines, HRSGs, and pollution control systems in accordance with the guidelines and procedures established by each manufacturer. The training shall include good operating practices as well as methods of minimizing excess emissions. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

14. Excess Emissions Prohibited: 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.~~ All such preventable emissions shall be included in any compliance determinations based on CEMS data.~~ [Rule 62-210.700(4), F.A.C.] [Comment: The last sentence should be deleted since there is no criteria for making such determinations. Moreover, the Rule cited does not include the additional requirement of excluding the data from CEMs measurement.]

15. Alternate Visible Emissions Standard: Visible emissions due to startups, shutdowns, and malfunctions shall not exceed 10% opacity except for up to ten, 6-minute averaging periods during a calendar day, which shall not exceed 20% opacity. [Rule 62-212.400(BACT), F.A.C.]

16. Excess Emissions Allowed: As specified in this condition, excess emissions resulting from startup, shutdown, fuel switches and~~ documented~~ malfunctions are allowed provided~~ that operators employ the~~ best operational practices to minimize emissions are adhered to~~the amount~~ and duration of excess emissions during such incidents are minimized. For each gas turbine/HRSG system, excess emissions resulting from startup, shutdown, fuel switches or~~ documented~~ malfunctions occurrences shall in no case exceed two hours (120 minutes) in any 24-hour period except for the following specific cases~~.~~ unless authorized by the Department for longer periods. [Comment: The suggested wording is more consistent with Department's rule. In addition, the term "documented" has no associated criteria from which any meaningful determination can be made.]

    a. For warm startup of the steam turbine~~to~~ during combined cycle operation, up to three hours of excess emissions are allowed. "Warm startup" is defined as a startup of the steam turbine~~to combined cycle operation~~ following a shutdown lasting at least 24 hours.

    b. For cold startup of the steam turbine~~to~~ during combined cycle operation, up to four hours of excess emissions are allowed. "Cold startup" is defined as a startup of the steam turbine~~to combined cycle~~

~~operation~~ following a shutdown lasting at least 48 hours.

c. For shutdown from combined cycle operation, up to three hours of excess emissions are allowed.

d. For *cold startup* of the heat recovery steam generator (HRSG) during combined cycle operation, excess emissions shall not exceed 240 minutes hours for any combustion turbine/HRSG train. "*Cold startup*" of the HRSG is defined as when the High Pressure (HP) steam drum is below 450 pounds per square inch (gage) for at least a one-hour period.

For days with simple cycle operation, excess emissions shall not exceed three hours in any 24-hour period due to all combined occurrences of startups, shutdowns, and malfunctions. For days with combined cycle operation, excess emissions shall not exceed 12~~four~~ hours in any 24-hour period due to all combined occurrences of startups, shutdowns, and malfunctions. For startup to combined cycle operation, ammonia injection shall begin as soon as operation of the gas turbine/HRSG system achieves the operating parameters specified by the manufacturer. As authorized by Rule 62-210.700(5), F.A.C., the above conditions allow excess emissions only for specifically defined periods of startup, shutdown, and documented malfunction of the gas turbines. Fuel switching is considered to be a startup/shutdown procedure allowing for excess emissions. [Design; Rules 62-212.400(BACT) and 62-210.700, F.A.C.] [Comment: FPL requests a condition similar to that approved for the Sanford and Fort Myers Repowering Projects. The steam turbine for Martin Unit 8 is larger than that associated with these Projects and the sequencing of the initial CT/HRSG trains may take more than 4 hours to reach compliance with emission limits. A permitting note was added to allow for fuel switching.]

17. Initial Steam Blows: Prior to completing the conversion from simple cycle to combined cycle operation, the permittee is authorized to operate each gas turbine at loads below 50% for the purpose of cleaning the HRSG piping system and piping connecting the HRSG to the steam turbine. Prior to conducting any steam blows, the permittee shall submit a proposed schedule. On the first day of conducting steam blows, the permittee shall notify the Compliance Authority that the process has begun. The permittee shall complete this process within a reasonable time~~90 days~~ of conducting the initial steam blow. During the steam blows, the following conditions apply:

a. The permittee shall take all precautions to minimize the extent and duration of excess emissions.

b. Each gas turbine shall fire only natural gas and each CEMS shall be on line and functioning~~properly~~.

c. CO and NOx emissions may exceed the BACT limits specified in this permit; however, NOx emissions shall not exceed the NSPS Subpart GG limit of 110 ppmvd corrected to 15% oxygen based on a 24-hour block average. If the NSPS standard is exceeded, the permittee shall notify the Compliance Authority within one working day~~24 hours~~ of the incident.

Within 30 days of completing the initial steam blows, the permittee shall submit a report to the Bureau of Air Regulation and the Compliance Authority summarizing the daily emissions resulting from each steam blow. This permit condition is only applicable if the simple cycle operation begins prior to combined cycle operation and compliance tests for simple cycle have not been performed. *{Permitting Note: It is estimated that steam blows will occur intermittently over a 30-day period for each gas turbine/HRSG system followed by a similar 60-day period of intermittent steam blows for the common piping system serving the four interconnected combined cycle units. It is not expected that steam blows would occur every day during these periods.}* [Application] [Comment: As described in the additional information supplied to the Department, the exact calendar period for steam blows cannot be determined. Steam blows are a necessary part of construction and should be limited to a specific duration. If simple cycle operation does not initially occur as part of the Project, the CEMs will not be operational and the required testing to assure the required accuracy and precision (i.e. RATA testing) will not have been performed.]

18. DLN Tuning: CEMS data collected during initial or other major DLN tuning sessions shall be excluded from the CEMS compliance demonstration provided the tuning session is performed in accordance with the manufacturer's specifications. A "major tuning session" would occur after completion of initial construction, a combustor change-out, a major repair or maintenance to a combustor, or other similar circumstances. Prior to performing any major tuning session, the permittee shall provide the Compliance Authority with an advance notice that details the activity and proposed tuning schedule. The notice may be by telephone, facsimile transmittal, or electronic mail. [Design; Rule 62-4.070(3), F.A.C.]

EMISSIONS PERFORMANCE TESTING

19. Test Methods: Any required tests shall be performed in accordance with the following reference methods.

Method	Description of Method and Comments
CTM-027	Procedure for Collection and Analysis of Ammonia in Stationary Source {Notes: This is an EPA conditional test method. The minimum detection limit shall be 1 ppm.}
5	~~Determination of Particulate Matter Emissions from Stationary Sources~~[Comment: NO PM testing is required by the permit.]
7E	Determination of Nitrogen Oxide Emissions from Stationary Sources
9	Visual Determination of the Opacity of Emissions from Stationary Sources
10	Determination of Carbon Monoxide Emissions from Stationary Sources {Notes: The method shall be based on a continuous sampling train.}
18	Measurement of Gaseous Organic Compound Emissions by Gas Chromatography {Note: EPA Method 18 may be used (optional) concurrently with EPA Method 25A to deduct emissions of methane and ethane from the measured VOC emissions.}
20	Determination of Nitrogen Oxides, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines
25A	Determination of Volatile Organic Concentrations

Method CTM-027 is published on EPA's Technology Transfer Network Web Site at "http://www.epa.gov/ttn/emc/ctm.html". The other methods are described in Appendix A of 40 CFR 60, adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used unless prior written approval is received from the Department. [Rules 62-204.800, F.A.C.; 40 CFR 60, Appendix A]

20. Initial Compliance Determinations: Each new gas turbine shall be stack tested to demonstrate initial compliance with the emission standards for CO, NOx, VOC, visible emissions, and ammonia slip. The tests shall be conducted within 60 days after achieving~~ at least 90% of the~~ maximum permitted capacity for each unit configuration (i.e., simple cycle and combined cycle operation), but not later than 180 days after the initial startup of each unit configuration. Each unit shall be tested when firing natural gas and distillate oil. CEMS data collected during the required Relative Accuracy Test Assessments (RATA) may be used to demonstrate compliance with the initial 3-hour CO and NOx standards.~~ With appropriate flow measurements and calculations, CEMS data may also be used to demonstrate compliance with the CO and NOx mass emissions standards.~~ CO and NOx emissions recorded by the CEMS shall also be reported for each run during tests for visible emissions, VOC and ammonia slip. ~~The Department may require the permittee to conduct initial tests after the replacement or repair of any air pollution control equipment, such as the SCR catalyst, DLN combustors, etc.~~ [Rule 62-297.310(7)(a)1., F.A.C.] [Comment: Deleting the phrase "at least 90% of the" would make the wording consistent with the NSPS requirements in Section 60.8 and the Department's previous permits. There will be no exhaust flow monitors required for the Project and the mass emissions can be determined using fuel measurements and "F"-Factors. The sentence

related to additional testing should be deleted since the department has this authority if non-compliance is suspected. Moreover, there will be CEMs for NO_x and CO, which provide compliance data.]

21. Continuous Compliance: The permittee shall demonstrate continuous compliance with the CO and NOx emissions standards based on data collected by the certified CEMS. Within 45 days of conducting any Relative Accuracy Test Assessments (RATA) on a CEMS, the permittee shall submit a report to the Compliance Authority summarizing results of the RATA. Compliance with the CO emission standards also serves as an indicator of efficient fuel combustion, which reduces emissions of particulate matter and volatile organic compounds. [Rule 62-212.400 (BACT), F.A.C.]

22. Annual Compliance Tests: During each federal fiscal year (October 1st to September 30th), each gas turbine shall be tested to demonstrate compliance with the emission standards for visible emissions and ammonia slip. NOx emissions recorded by the CEMS shall be reported for each ammonia slip test run. CO emissions recorded by the CEMS shall be reported for the visible emissions observation period. *{Permitting Note: After initial compliance with the VOC standards is demonstrated, annual compliance tests for VOC emissions are not required. Compliance with the continuously monitored CO standards shall indicate efficient combustion and low VOC emissions.}* [Rules 62-212.400 (BACT) and 62-297.310(7)(a)4., F.A.C.]

CONTINUOUS MONITORING REQUIREMENTS

23. CEM Systems: The permittee shall install, calibrate, maintain, and operate continuous emission monitoring systems (CEMS) to measure and record the emissions of CO and NOx from the combined cycle gas turbine in a manner sufficient to demonstrate continuous compliance with the CEMS emission standards of this section. Each monitoring system shall be installed and certified according to 40 CFR Part 75~~, calibrated, and properly functioning prior to the initial performance tests and commencement of commercial operation.~~ Within one working day of discovering emissions in excess of a CO or NOx standard set forth in Condition 9 (and subject to the specified averaging period), the permittee shall contact the Compliance Authority. [Comment: 40 CFR 75.4 states the CEMS shall be certified the earlier of 90 unit operating days or 180 calendar days after commercial operation. This criteria should be used as it will not be definitively known if the CEMS are 'properly functioning' until all certification tests have been successfully completed. Also, the 90 unit operating day period allows sufficient time for debugging of the unit and the CEMS before data is reported for the Acid Rain Program.]

    a. *CO Monitors.* The CO monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4 or 4A. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, and the Data Assessment Report of Section 7 shall be made each calendar quarter, and reported semiannually to the Compliance Authority. The RATA tests required for the CO monitor shall be performed using EPA Method 10 in Appendix A of 40 CFR 60 and shall be based on a continuous sampling train. The CO monitor span values ~~shall have multi-span capability with~~be set appropriately ~~spans established~~ for the methods of operation (simple cycle gas firing, combined cycle gas firing, simple cycle oil firing, combined cycle oil firing, etc.). ~~{Permitting Note: The alternate standards for steam blows will require even higher span values.}~~ [Comment: PS 4A will likely be more appropriate than PS 4 due to expected CO emissions levels. A single range CO monitor may be able to record emissions consistent with the limits set in Specific Condition 10. See comments to Specific Condition 17.]

    b. *NOx Monitors.* Each NOx monitor shall be certified, operated and maintained pursuant to the applicable requirements of 40 CFR Part 75. ~~and shall be operated and maintained in accordance with the applicable requirements of 40 CFR Part 75, Subparts B and C.~~ Record keeping and reporting shall be conducted pursuant to 40 CFR Part 75, Subparts F and G. The RATA tests required for the NO_X

monitor span value(s) shall be set according to 40 CFR Part 75, Appendix A~~performed using EPA Method 20 or 7E in Appendix A of 40 CFR 60. The NOx monitor shall have multi-span capability with appropriate spans established for the methods of operation (simple cycle gas firing, combined cycle gas firing, simple cycle oil firing, combined cycle oil firing, etc.).~~ {Permitting Note: The alternate standards for steam blows will require even higher span values.} [Comment: A single range NOx monitor may be able to record emissions consistent with the emissions limits set in Specific Condition 10. See comments to Specific Condition 17.]

c. *O_2 or CO_2 Monitors.* The oxygen (O_2) content or carbon dioxide (CO_2) content of the flue gas shall also be monitored at the location where CO and/or NOx are monitored to correct the measured emissions rates to 15% oxygen. If a CO_2 monitor is installed, the oxygen content of the flue gas shall be calculated by the CEMS using F-factors that are appropriate for the fuel fired. Each monitor shall be certified, operated and manitained pursuant to 40 CFR 75 as the "diluent" monitor of the "NOx-diluent" system.~~60, Appendix B, Performance Specification 3. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, and the Data Assessment Report of Section 7 shall be made each calendar quarter, and reported semiannually to the Compliance Authority. The RATA tests required for the O_2 or CO_2 monitors shall be performed using EPA Method 3B, of Appendix A of 40 CFR 60.~~ [Comment: the O2 or CO2 monitor installed is known as the 'diluent' monitor included in the 'NOx-diluent' monitoring system under 40 CFR 75. For consistency the NOx and O2/CO2 monitors should be subject to the same regulatory routines, i.e. Part 75. Under Part 75, no separate RATA is required for the diluent monitor as the RATA results are reported for the NOx-diluent system (rather than for the individual NOx and O2/CO2 analyzers) in units of lb/MMBtu.]

d. *1-Hour Block Averages.* Hourly average values shall begin at the top of each hour. Each hourly average value shall be computed using at least one data point in each fifteen-minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, an hourly value shall be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour). If less than two such data points are available, the hourly average value is not valid. The permittee shall use all valid measurements or data points collected during an hour to calculate the hourly average values. . For purposes of determining compliance with the CEMS standards, missing (or excluded) data shall not be included in the 1-hour block averages. The CEMS shall be designed and operated to sample, analyze, and record data evenly spaced over an hour. If the CEMS measures concentration on a wet basis, the CEM system shall include provisions to determine the moisture content of the exhaust gas and an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Alternatively, the owner or operator may develop through manual stack test measurements a curve of moisture contents in the exhaust gas versus load for each allowable fuel, and use these typical values in an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Final results of the CEMS shall be expressed as ppmvd corrected to 15% oxygen. The CEMS shall be used to demonstrate compliance with the CEMS emission standards for CO and NOx as specified in this permit. Upon request by the Department, the CEMS emission rates shall be corrected to ISO conditions to demonstrate compliance with the applicable standards of 40 CFR 60.332. [Comment: missing or substituted data should not be included for compliance as is stated in (e) below.]

e. *3-hour Block Averages*: For oil firing during simple cycle operation, the 3-hour block average shall be calculated from three consecutive hourly average emission rate values. For purposes of determining compliance with the CEMS emission standards of this permit, missing (or excluded) data shall not be substituted. Instead, the 3-hour block average shall be determined using the remaining hourly data in the 3-hour block. [Rule 62-212.400(BACT), F.A.C.]

f. *24-hour Block Averages*: A 24-hour block shall begin at midnight of each operating day and shall be calculated from 24 consecutive hourly average emission rate values. If a unit operates less than 24 hours during the block, the 24-hour block average shall be the average of available valid hourly average emission rate values for the 24-hour block. For purposes of determining compliance with the 24-hour CEMS standards, missing (or excluded) data shall not be substituted. Instead, the 24-hour block average shall be determined using the remaining hourly data in the 24-hour block. {Permitting Note: There may be more than one 24-hour compliance demonstration for CO and NOx emissions depending on the use of alternate methods of operation. [Rule 62-212.400(BACT), F.A.C.]

g. *Data Exclusion.* Each CEMS shall monitor and record emissions during all operations including all episodes of startup, shutdown,~~ and~~ malfunction, fuel switches, DLN Tuning and steam blows. CEMS emissions data recorded during such episodes may be excluded from the corresponding CEMS compliance demonstration subject to the provisions of Condition Nos. 16~~16~~, 17 and 18 of this section. ~~All periods of data excluded shall be consecutive for each such episode. The permittee shall minimize the duration of data excluded for such episodes to the extent practicable. Data recorded during such episodes shall not be excluded if the episode was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented. Best operational practices shall be used to minimize hourly emissions that occur during such episodes. Emissions of any quantity or duration that occur entirely or in part from poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented, shall be prohibited.~~ [Comment: The remaining language in the paragraph is redundant to previous conditions.]

h. *Availability.* Monitor availability for the CEMS shall meet the performance specification of 40 CFR Part 75~~be 95% or greater in any calendar quarter~~. The quarterly permit excess emissions report shall be used to provide information~~demonstrate~~ monitor availability. In the event monitor~~95%~~ availability required by 40 CFR Part 75 is not achieved, the permittee shall provide the Department with a report identifying the problems in achieving monitor~~95%~~ availability and a plan of corrective actions that will be taken to achieve monitor~~95%~~ availability. The permittee shall implement the reported corrective actions within the next calendar quarter. ~~Failure to take corrective actions or continued failure to achieve the minimum monitor availability shall be violations of this permit.~~[Comment: Any requirements for monitoravailability should be consistent with 40 CFR Part 75.]

~~{Permitting Note:~~ Compliance with these requirements ensure compliance with the other applicable CEM system requirements such as: NSPS Subparts Da and GG; Rule 62-297.520, F.A.C.; 40 CFR 60.7(a)(5) and 40 CFR 60.13; 40 CFR Part 51, Appendix P; 40 CFR 60, Appendix B - Performance Specifications; and 40 CFR 60, Appendix F - Quality Assurance Procedures.~~}~~ [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.] [Comment: The permitting note should be a permit condition, since compliance with Subparts GG and Da are important.]

24. Water Injection Monitoring Requirements: In accordance with the manufacturer's specifications, the permittee shall install, calibrate, operate and maintain a monitoring system to continuously measure and record the water-to-fuel ratio when firing distillate oil. The permittee shall document the water-to-fuel ratio required to meet permitted emissions levels over the range of load conditions allowed by this permit. During NOx monitor downtimes or malfunctions, the permittee shall operate at the water-to-fuel ratio that is consistent with the documented flow rate for the gas turbine load condition. ~~{Permitting Note: The water-to-fuel ratio at maximum load to achieve the NOx standards during simple cycle oil firing is approximately 1.10 or a water injection rate of approximately 101,000 pounds per hour.}~~ [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.][Comment: The water injection rate will vary based on the GE control system.]

25. Ammonia Monitoring Requirements: In accordance with the manufacturer's specifications, the permittee shall install, calibrate, operate and maintain an ammonia flow meter to measure and record the ammonia injection rate to the SCR system. The permittee shall document the general range of ammonia flow rates required to meet permitted emissions levels over the range of load conditions allowed by this permit by comparing NOx emissions recorded by the CEM system with ammonia flow rates recorded using the ammonia flow meter. During NOx monitor downtimes or malfunctions, the permittee shall operate at the ammonia flow rate that is consistent with the documented flow rate for the combustion turbine load condition. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

RECORDS AND REPORTS

26. Monitoring of Capacity: ~~To demonstrate compliance with the permitted capacities, t~~The permittee shall monitor and record the operating rate of each combined cycle gas turbine HRSG duct burner system on a daily average basis, considering the number of hours of operation during each day (including the times of startup, shutdown and malfunction). Such monitoring shall be made using a monitoring component of the CEM system required above, or by monitoring daily rates of consumption and heat content of each allowable fuel in accordance with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.] [Comment: See comments to Specific Conditions 7 and 8.]

27. Monthly Operations Summary: By the fifth calendar day of each month, the permittee shall record the following for each fuel in a written or electronic log for each gas turbine for the previous month of operation: fuel consumption, hours of operation, hours of power augmentation, hours of peaking, hours of duct firing, and the updated 12-month rolling totals for each. Information recorded and stored as an electronic file shall be available for inspection and printing within at least three days of a request by the Department. The fuel consumption shall be monitored in accordance with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

28. Fuel Sulfur Records: The permittee shall demonstrate compliance with the fuel sulfur limits specified in this permit by maintaining the following records of the sulfur contents.

    a. Compliance with the fuel sulfur limit for natural gas shall be demonstrated by keeping reports obtained from the vendor indicating the average sulfur content of the natural gas pursuant to 40 CFR Part 75~~being supplied from the pipeline for each month of operation.~~ Methods for determining the sulfur content of the natural gas shall be ASTM methods D4084-82, D3246-81 or more recent versions.

    b. Compliance with the distillate oil sulfur limit shall be demonstrated by taking a sample, analyzing the sample for fuel sulfur, and reporting the results to each Compliance Authority before initial startup. Sampling the fuel oil sulfur content shall be conducted in accordance with ASTM D4057-88, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, and one of the following test methods for sulfur in petroleum products: ASTM D129-91, ASTM D1552-90, ASTM D2622-94, or ASTM D4294-90. More recent versions of these methods may be used. For each subsequent fuel delivery, the permittee shall maintain a permanent file of the certified fuel sulfur analysis from the fuel vendor. At the request of a Compliance Authority, the permittee shall perform additional sampling and analysis for the fuel sulfur content.

    The above methods shall be used to determine the fuel sulfur content in conjunction with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-4.160(15), F.A.C.]

29. Excess Emissions Notification: If a CEMS reports emissions in excess of an emissions standard listed in Condition 9 (and subject to the specified averaging periods~~or the permittee observes visible emissions in excess of a standard~~, the permittee shall notify the Compliance Authority within one working day of occurrence. Allowable excess emissions for startups, shutdowns, fuel switches, malfunctions, steam blows

and DLN tuning, as described in Specific Condition 16, 17 and 18 are excluded from determining compliance. The notification shall include a preliminary report of: the nature, extent, and duration of the emissions; the probable cause of the emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident. [Rule 62-210.700, F.A.C.] [Comment: The VE standard requires a trained observed and such reporting is not possible. Moreover, Manatee Unit 3 will exclusively use natural gas and such reporting is unnecessary. Notification of allowable excess emission should be excluded from the notification. Such allowable excess emissions are reported in the quarterly report.]

30. Semiannual NSPS Excess Emissions Report: In accordance with 40 CFR 60.7(d), the permittee shall submit a report to the Compliance Authority summarizing any emissions in excess of the NSPS standards within 30 days following the end of each calendar quarter. For purposes of reporting emissions in excess of NSPS Subpart GG, excess emissions from the gas turbine are defined as: any CEMS hourly average value exceeding the NSPS NOx emission standard identified in Appendix GG; and any daily period during which the sulfur content of the fuel being fired in the gas turbine exceeds the NSPS standard identified in Appendix GG. For purposes of reporting emissions in excess of NSPS Subpart Da, excess emissions from duct firing are defined as: NOx or PM emissions in excess of the NSPS standards except during periods of startup, shutdown, or malfunction; and SO_2 emissions in excess of the NSPS standards except during startup or shutdown. [40 CFR 60.7]

31. Quarterly Permit Excess Emission Report: Within 30 days following the end of each quarter, the permittee shall submit a report to the Compliance Authority summarizing periods of excess CO and NOx emissions. Such information shall also be summarized for simple/combined cycle startups, simple/combined cycle shutdowns, malfunctions, and major tuning sessions. In addition, the report shall summarize the CEMS systems monitor availability for the previous quarter. [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C.; and 40 CFR 60.7]

B. GAS-FIRED FUEL HEATERS

This section of the permit addresses the following emissions units.

ID	Emission Unit Description
013	Four gas-fired fuel heaters, 22 MMBtu/hour each

APPLICABLE REQUIREMENTS

1. ~~NSPS Requirements: The gas-fired fuel heaters are subject to the New Source Performance Standards for Small Industrial-Commercial-Institutional Steam Generating Units specified in Subpart Dc of 40 CFR 60. The units are subject to the record keeping and reporting requirements of this regulation, which are summarized in Appendix Dc of this permit. [Rule 62-204.800(7), F.A.C.; 40 CFR 60, Subpart Dc]~~[Comment: Subpart Dc does not apply to direct fired gas heaters.]

EQUIPMENT

2. Gas-Fired Fuel Heaters: The permittee is authorized to install two new 22 MMBtu per hour (LHV) fuel heaters. *{Permitting Note: The two new units will be added to two existing units under EU 013. The gas-fired fuel heaters heat the natural gas prior to firing in the "hot nozzle" dry low NOx combustors to increase cycle efficiency. The fuel heaters operate continuously during simple cycle operation and for startup to combined cycle operation. Once combined cycle operation is established, the fuel heaters are shut down and a small heat exchanger in the HRSG exhaust is used to preheat the natural gas prior to combustion in the gas turbines.}* [Application; Design]

PERFORMANCE REQUIREMENTS

3. Permitted Capacity: Based on the lower heating value (LHV) of natural gas, each gas-fired fuel heater shall not exceed 22 MMBtu per hour. [Application; Rule 62-210.200(PTE), F.A.C.]

4. Authorized Fuel: Each fuel heater shall fire only natural gas, which shall contain no more than 2.0 grains of sulfur per 100 standard cubic feet of natural gas. [Rules 62-212.400(BACT) and 62-210.200(PTE), F.A.C.]

EMISSIONS STANDARDS

5. Visible Emissions: Visible emissions from each gas-fired fuel heater shall not exceed 10% opacity (6-minute block average) except for 10~~one~~ 6-minute block average, which shall not exceed 20% opacity due to startups, shutdowns or malfunctions. [Rule 62-212.400(BACT), F.A.C.] . [Comment: The deleted phrases better clarify the intent of the condition. Also, the terminology can be confusing since there are no criteria specified in the permit.]

TESTING, RECORDS, AND REPORTING

6. Fuel Consumption: Equipment shall be installed and maintained to monitor the consumption of natural gas for each fuel heater. The monitoring system shall be capable of totaling the daily natural gas consumption. Natural gas consumption shall be reported in the Annual Operating Report. [40 CFR 60, Subpart Dc; Rule 62-210.370(2), F.A.C.

7. Fuel Sulfur: Compliance with the fuel sulfur limit for natural gas shall be demonstrated by keeping reports obtained of the sulfur content required in Section III, Part A. ~~from the vendor indicating the average sulfur content of the natural gas being supplied from the pipeline for each month of operation. Methods for determining the sulfur content of the natural gas shall be ASTM methods D4084-82, D3246-81 or more recent versions.~~ [Rule 62-4.070(3), F.A.C.] [Comment: The fuel heaters will use the same natural gas as the combustion turbines and any sulfur monitoring condition specific to the fuel heaters is unnecessary.]

B. GAS-FIRED FUEL HEATERS

8. Visible Emissions Tests: To determine compliance with the visible emissions standard, the permittee shall conduct testing in accordance with EPA Method 9. Initial compliance tests shall be conducted within 60 days of initial startup. Annual tests shall be conducted during each federal fiscal year if the hours of operation exceed 400 hours within the annual period. The permittee shall notify the Compliance Authority of scheduled tests at least 15 days in advance. Test results shall be submitted to the Compliance Authority within 45 days of conducting the tests. [40 CFR 60, Appendix A; Rules 62-204.800(7), 62-297.310(7)(a)9, 62-297.310(8)(c), F.A.C.] [Comment: Annual compliance tests are unnecessary for these small fuel gas heaters that exclusively fire natural gas.]

C. COOLING TOWER

This section of the permit addresses the following new emissions unit.

ID	Emission Unit Description
020	18-cell mechanical draft cooling tower

EQUIPMENT

1. Cooling Tower: The permittee is authorized to install one new 18-cell mechanical draft cooling tower with the following design characteristics: a circulating water flow rate of 310,000 gpm; design hot/cold water temperatures of 104° F/90° F; a design air flow rate of 1,386,055 per cell; a liquid-to-gas air flow ratio of 1.4; and drift eliminators with a drift rate of no more than 0.001 percent. The permittee shall submit the final design details within 60 days of selecting the vendor. [Application; Design]

EMISSIONS AND PERFORMANCE REQUIREMENTS

2. Drift Rate: The cooling tower shall be designed~~, operated, and maintained to reduce~~to meet a ~~the~~ drift rate of~~to~~ no more than 0.001 percent of the circulating water flow rate. The permitee shall provide such a certification to the Department upon construction of the cooling tower. *{Permitting Note: This work practice standard is established as BACT for PM/PM_{10} emissions from the cooling tower. Based on this design criteria, potential emissions are expected to be less than 34 tons of PM per year and less than 10 tons of PM_{10} per year. Actual emissions are expected be less than half these rates.}*. [Rule 62-212.400(BACT), F.A.C.][Comment: Once constructed there are no operational or maintenance requirements regarding the drift eliminators.]

NSPS SUBPART Da REQUIREMENTS FOR DUCT BURNERS

Except as provided below, ~~T~~the duct burners in the heat recovery steam generators (HRSGs) are subject to the applicable requirements of Subpart A (General Provisions) and Subpart Da (Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978) established as New Source Performance Standards in 40 CFR 60 and adopted by reference in Rule 62-204.800(7)(b), F.A.C. The specific federal requirements are not listed, but can be obtained from the Department upon request. [Some of the NSPS requirements are being waived, so this notation is appropriate.]

NSPS GENERAL PROVISIONS

The emissions units are subject to the applicable General Provisions of the New Source Performance Standards including 40 CFR 60.7 (Notification and Record Keeping), 40 CFR 60.8 (Performance Tests), 40 CFR 60.11 (Compliance with Standards and Maintenance Requirements), 40 CFR 60.12 (Circumvention), 40 CFR 60.13 (Monitoring Requirements), and 40 CFR 60.19 (General Notification and Reporting Requirements), except as provided below. [Some of the NSPS requirements are being waived, so this notation is appropriate.]

NSPS SUBPART Da REQUIREMENTS

The duct burners in the heat recovery steam generators (HRSGs) shall comply with the following federal requirements of 40 CFR 60, Subpart Da, except as provided below.~~:~~

§ 60.40a Applicability and designation of affected facility.
§ 60.41a Definitions.
§ 60.42a Standard for particulate matter.
§ 60.43a Standard for sulfur dioxide.
§ 60.44a Standard for nitrogen oxides.
§ 60.46a Compliance provisions.
§ 60.47a Emission monitoring.
§ 60.48a Compliance determination procedures and methods.
§ 60.49a Reporting requirements.

~~*Permitting Notes:*~~*[These provisions should be regular conditions of the permit rather than permitting notes.]*

- *The duct burners have a heat input greater than 250 MMBtu per hour and are subject to NSPS Subpart Da.*
- *Particulate matter emissions are limited to 0.03 lb/million Btu heat input derived from the combustion of gaseous fuel. The exclusive firing of natural gas with a sulfur content not to exceed, on average, 2 grains per 100 standard cubic feet of gas ~~is expected to~~will result in particulate matter emissions of less than 0.008 lb/MMBtu. Initial performance testing and monitoring under 40 CFR 60.46a, 60.47a, and 60.48a are not required to demonstrate compliance with the applicable particulate matter limit. [Without this or similar language, an initial performance test using EPA Method 19 would be required. As established in the BACT determination and PSD permit, stack testing for particulate matter is unnecessary.]~~]~~*
- *Sulfur dioxide emissions are limited to 0.20 lb/million Btu heat input based on 100 percent of the potential combustion concentration (zero percent reduction). The exclusive firing of natural gas with a sulfur content not to exceed, on average, 2 grains per 100 standard cubic feet of gas will ~~is expected to~~ result in sulfur dioxide emissions of less than 0.005 lb/MMBtu. Initial performance testing and monitoring under 40 CFR 60.46a, 60.47a, and 60.48 are not required to demonstrate compliance with the applicable sulfur dioxide limit. [Without this or similar language, an initial performance test using EPA Method 19 would be required. As established in the BACT determination and PSD permit, stack testing for sulfur dioxide is unnecessary.]*
- *Nitrogen oxide emissions are limited to 1.6 pounds per megawatt-hour (MWhr) (gross energy output) as provided under § 60.46a(k)(1). Compliance with the emissions limit is determined by the three-run average (nominal 1-hour runs) for the initial performance test under 40 CFR 60.46a(k)~~and subsequent performance tests~~. The combined gas turbine and duct burner emissions are limited to 2.5 parts per million (ppm) under BACT(equivalent to 0.1 lb/MW-hr), which is much lower than the NSPS standard. ~~readily comply with this standard.~~ Compliance with the BACT*

limit of 2.5 ppm, determined using a continuous emissions monitoring system, will ensure compliance with the NSPS limit of 1.6 lb/MWhr and no subsequent stack tests are required. [Future stack testing, beyond the initial performance test, should not be necessary with the very low 2.5 ppm limit that applies to these units.]

NSPS SUBPART Dc REQUIREMENTS FOR GAS-FIRED FUEL HEATERS

~~The following emissions units are subject to the applicable requirements of Subpart A (General Provisions) and Subpart Dc (Small Industrial Commercial Institutional Steam Generating Units) established as New Source Performance Standards in 40 CFR 60 and adopted by reference in Rule 62-204.800(7)(b), F.A.C. The specific federal requirements are not listed, but can be obtained from the Department upon request.~~

~~ID~~	~~Emission Unit Description~~
~~013~~	~~Four gas-fired fuel heaters~~

~~NSPS GENERAL PROVISIONS~~

~~The emissions units are subject to the applicable General Provisions of the New Source Performance Standards including 40 CFR 60.7 (Notification and Record Keeping), 40 CFR 60.8 (Performance Tests), 40 CFR 60.11 (Compliance with Standards and Maintenance Requirements), 40 CFR 60.12 (Circumvention), 40 CFR 60.13 (Monitoring Requirements), and 40 CFR 60.19 (General Notification and Reporting Requirements).~~

~~NSPS SUBPART Dc REQUIREMENTS~~

~~The gas-fired fuel heaters shall comply with the following federal requirements of 40 CFR 60, Subpart Dc.~~

~~§ 60.40c Applicability and delegation of authority.~~
~~§ 60.41c Definitions.~~
~~§ 60.42c Standard for sulfur dioxide.~~
~~§ 60.43c Standard for particulate matter.~~
~~§ 60.44c Compliance and performance test methods and procedures for sulfur dioxide.~~
~~§ 60.45c Compliance and performance test methods and procedures for particulate matter.~~
~~§ 60.46c Emission monitoring for sulfur dioxide~~
~~§ 60.47c Emission monitoring for particulate matter.~~
~~§ 60.48c Reporting and record keeping requirements.~~

~~*Permitting Notes:*~~

- ~~*NSPS Subpart Dc defines steam generating unit to mean, "... a device that combusts any fuel and produces steam or heats water or any other heat transfer medium." Because the fuel heaters have a heat input of 22 MMBtu per hour each and heat natural gas prior to combustion in the gas turbines, the units are subject to NSPS Subpart Dc.*~~
- ~~*Because the fuel heaters fire only natural gas, these units are subject only to notification, record keeping, and reporting requirements. The Department believes that the specific conditions of the permit are sufficient to demonstrate compliance with NSPS Subpart Dc.*~~

NSPS SUBPART GG REQUIREMENTS FOR GAS TURBINES

Except as provided below, t~~T~~he following emissions units are subject to the applicable requirements of Subpart A (General Provisions) and Subpart GG (Stationary Gas Turbines) established as New Source Performance Standards in 40 CFR 60 and adopted by reference in Rule 62-204.800(7)(b), F.A.C. The specific federal requirements are not listed, but can be obtained from the Department upon request. [Some of the NSPS requirements are being waived, so this notation is appropriate.]

ID	Emission Unit Description
011	Unit 8A Gas Turbine (170 MW) with Heat Recovery Steam Generator
012	Unit 8B Gas Turbine (170 MW) with Heat Recovery Steam Generator
017	Unit 8C Gas Turbine (170 MW) with Heat Recovery Steam Generator
018	Unit 8D Gas Turbine (170 MW) with Heat Recovery Steam Generator

NSPS GENERAL PROVISIONS

The emissions units are subject to the applicable General Provisions of the New Source Performance Standards including 40 CFR 60.7 (Notification and Record Keeping), 40 CFR 60.8 (Performance Tests), 40 CFR 60.11 (Compliance with Standards and Maintenance Requirements), 40 CFR 60.12 (Circumvention), 40 CFR 60.13 (Monitoring Requirements), and 40 CFR 60.19 (General Notification and Reporting Requirements), except as provided below. [Some of the NSPS requirements are being waived, so this notation is appropriate.]

NSPS SUBPART GG REQUIREMENTS

The gas turbines shall comply with the following federal requirements, except as provided below.

§ 60.330 Applicability and designation of affected facility.
§ 60.331 Definitions.
§ 60.332 Standard for Nitrogen Oxides.
§ 60.333 Standard for Sulfur Dioxide.
§ 60.334 Monitoring of Operations.
§ 60.335 Test Methods and Procedures.

~~*Permitting Notes:*~~

- *Based on the manufacturer's data and compressor inlet conditions of 59° F and 60% relative humidity, the heat rate for gas firing is 9250 Btu/KW-h at peak load and for oil firing is 9960 Btu/KW-h at peak load. This results in "Y" values of 9.8 for gas firing and 10.5 for oil firing. The equivalent NSPS NOx emission standards are 110/103 ppmvd at 15% oxygen for gas/oil firing. The emissions standards of the PSD permit are more stringent than this requirement. When firing natural gas, the "F" value (NOx allowance for fuel bound nitrogen shall be assumed to be 0. ~~See EPA's March 12, 1993 determination regarding the use of NOx CEMS.~~ [This notation should be deleted or the determination should be attached.]*
- *The gas turbine is limited to firing any fuel that contains sulfur in excess of 0.8 percent by weight.*
- *The requirement to monitor the nitrogen content of natural gas fired ~~(Martin only)~~ and fuel oil is waived. A NOx CEMS complying with the requirements of 40 CFR Part 75 shall be used to demonstrate compliance with the NOx limits of this permit. This is consistent with the custom fuel monitoring policy and guidance from EPA Region 4. [This note will clarify the certification requirements for the CEM and prevent any potential conflicts between Parts 60 and 75 monitoring certification requirements.]*
- *The permit contains a custom monitoring schedule for determining the sulfur content of fuels that is sufficient to demonstrate compliance with the NSPS limit. It is consistent with the custom fuel monitoring policy and guidance from EPA Region 4.*
  - *The permittee shall apply for an Acid Rain permit within 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 the use of natural gas (sulfur content less than 2 gr/100 scf)~~) (Martin only:~~ and fuel oil~~)~~ for the CT's.*
- *Each unit shall be monitored for SO2 emissions using methods consistent with the requirements of 40 CFR 75 and certified by the USEPA.*
- ~~*(Martin only)*~~ *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 Martin Power Plant, an analysis which reports the sulfur 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).*

[This custom fuel monitoring schedule has previously been approved by EPA and DEP, is included in the current PSD permit for the two existing Martin combustion turbines, and would be appropriate for the new Martin ~~and Manatee~~ units as well.]

- *Emissions in excess of the NSPS standard for nitrogen oxides shall be determined on 1-hour basis. The continuous compliance demonstration by NOx CEM system data shall substitute for the NSPS requirements regarding the water-to-fuel ratio~~n~~. NOx CEM system data shall be used to determine "excess emissions" for purposes of 40 CFR 60.7 subject to the conditions of the permit. ~~As required by EPA's March 12, 1993 determination, the NOx monitor shall meet the applicable requirements of 40 CFR 60.13, Appendix B and Appendix F for certifying, maintaining, operating and assuring the quality of the system; shall be capable of calculating NOx emissions concentrations corrected to 15% oxygen; shall have no less than 95% monitor availability in any given calendar quarter; and shall provide a minimum of four data points for each hour and calculate an hourly average. The requirements for the CEM systems specified by the specific conditions of this permit satisfy these requirements.]~~ [The monitor should meet 40 CFR Part 75, rather than Part 60, requirements. The 95 percent monitor availability requirement is not established under NSPS, but is included in the permit as a BACT requirement.]*
- *Emissions in excess of the NSPS standard for sulfur dioxide shall be determined on a daily basis. However, the frequency specified in the custom fuel monitoring schedule is sufficient to demonstrate compliance with the with the NSPS limit. It is consistent with the custom fuel monitoring policy and guidance from EPA Region 4.*
- *The permittee is required to submit a semiannual report of emission in excess of the NSPS standards as required by 40 CFR 60.7, Subpart A, General Provisions.*
- *The Department may request that NOx emission data also be presented in terms of the NSPS standard (NOx at 15 percent O_2 and ISO standard ambient conditions, volume percent). The permittee is not required to have the NOx monitor continuously correct NOx emissions concentrations to ISO conditions. However, the permittee shall keep records of the data needed to make the correction, and shall make the correction when required by the Department or Administrator. This is consistent with guidance from EPA Region 4.*
- *The permittee is allowed to conduct initial performance tests at a single load because the permit requires demonstration of continuous compliance with the NOx BACT standards. This is consistent with guidance from EPA Region 4. ~~(Martin only)~~ Initial performance tests on the two existing combustion turbines have already been completed and no additional stack testing is required.*
- *The permittee is allowed to make the initial compliance demonstration for NOx emissions using certified CEM system data, provided that compliance is based on a minimum of three test runs representing a total of at least three hours of data, and that the CEMS be calibrated in accordance with the procedure in section 6.2.3 of Method 20 following each run. Alternatively, initial compliance may be demonstrated using data collected during the initial relative accuracy test audit (RATA) performed pursuant to 40 CFR Part 75~~on the NOx monitor~~. The span value specified in 40 CFR Part 75~~the permit~~ shall be used instead of that specified in the NSPS requirements. ~~Flow rate d~~Data shall be obtained to calculate mass emission rates. These initial compliance demonstration requirements are consistent with guidance from EPA Region 4. The span value is changed pursuant to Department authority and is consistent with guidance from EPA Region 4.*

NSPS Subpart GG Requirements for Gas Turbines

- *The permit species sulfur testing methods and allows the permittee to follow the requirements of 40 CFR 75 Appendix D to determine the sulfur content. These requirements allow different methods than provided by the NSPS requirements, but are equally stringent and will ensure compliance with this rule.*
- *The fuel analysis requirements of the permit meet or exceed the NSPS requirements and ensure compliance.*

Golder Associates Inc.

6241 NW 23rd Street, Suite 500
Gainesville, FL 32653-1500
Telephone (352) 336-5600
Fax (352) 336-6603

Golder Associates

August 7, 2002

0137609

Mr. C.H. Fancy, P.E., Chief
Bureau of Air Regulation
Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Attention: Mr. Jeff Koerner, New Source Review Section

RE: REVISED REGIONAL HAZE ANALYSIS FOR THE PREVENTION OF SIGNIFICANT DETERIORATION APPLICATION FOR THE FPL MARTIN EXPANSION PROJECT

Dear Jeff:

On behalf of Florida Power and Light Company (FPL), Golder Associates Inc. (Golder) is providing a revised regional haze analysis for the proposed Martin Expansion Project. The revision is due to a change made to the nitrate switch setting in the CALPOST program.

The change results in higher regional haze impacts for the proposed project. The resulting maximum values (i.e., 1.91 percent for simple-cycle operation and 4.90 percent for combined-cycle operation on fuel oil) remain below the Federal Land Manager's visibility screening criteria of 5 percent. There are no other changes to the application.

Attached are the pages that were revised in the Air Construction Permit/PSD application. The revised air modeling computer files are being provided electronically to Cleve Holladay. If you have any questions, please call me at (352) 336-5600 ext 539 or Ken Kosky at ext 516. Thank you.

Sincerely yours,

GOLDER ASSOCIATES INC.

Steven R. Marks

Steven R. Marks, CCM
Associate

Kennard F. Kosky

Kennard F. Kosky, PE
Project Manager

Attachments

SRM/jkw

cc: K. H. Simmons, FPL
C. Holladay, DEP

P:\Projects\2001\0137609 FPL Fort Myers-Martin-Manatee\4 Martin\4.1\080702\L080702.doc 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. An index that simply quantifies the percent change in visibility due to the operation of a source is calculated as:

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

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

The purpose of the visibility analysis is to calculate the extinction at each receptor for each day (24-hour period) of the year due to the proposed Project. The criteria to determine if the Project's impacts are potentially significant are based on a change in extinction of 5 percent or greater for any day of the year.

Processing of visibility impairment for this study was performed with the CALPUFF model (see Appendix D) and the CALPUFF post-processing program CALPOST. The analysis was conducted in accordance with the most recent guidance from the FLAG report (December 2000). The CALPUFF postprocessor model CALPOST is used to calculate the combined visibility effects from the different pollutants that are emitted from the Project. Daily background extinction coefficients are calculated on a hour-by-hour basis using hourly relative humidity data from CALMET and hygroscopic and non-hygroscopic extinction components specified in the FLAG document. For the Class I area evaluated, the hygroscopic and non-hygroscopic components are 0.9 and 8.5 inverse mega meter (Mm^{-1}). CALPOST then predicts the percent extinction change for each day of the year.

The regional haze analysis was performed for both simple cycle and combined cycle configurations. For simple cycle configuration, the analysis was performed for two simple cycle units (Units 8C and 8D) since two simple cycle units (Units 8A and 8B) are existing units and modeling was performed for these units when originally permitted. The simple cycle configuration of these units not being modified, but is modified by the combined cycle configuration. For combined cycle configuration, the emissions inventory was adjusted to remove double counting emissions of PM/PM_{10}, sulfur dioxide (SO_2) and sulfuric acid mist. The emissions of these pollutants were determined independently as provided in Appendix A. For PM/PM_{10}, emissions were increased by conservatively assuming that 9.8 percent of the SO_2 was converted to particulate by the reaction of ammonia used in the SCR system with SO_3 to form ammonium sulfate. Sulfuric acid mist emissions were conservatively assumed to be 10 percent of the SO_2 emissions. The overall conversion of SO_2 to particulate and sulfuric acid mist was assumed to be about 20 percent (i.e., 19.8 percent), which provided very conservative emission rates for individual pollutants. However, no change in the potential SO_2 emission was made and it was assumed that the preferential reaction of ammonia and SO_3 was not controlling. To eliminate double counting of SO_2 conversions in the regional haze analysis when firing oil, the actual sulfuric acid missions and additional particulate emissions were assumed to be one-half of the values when the pollutant formation is considered separately. In addition, the SO_2 emissions are reduced proportionally based on the conversion of PM/PM_{10} and sulfuric acid mist. These assumptions provide conservative emission estimates for the regional haze analysis.

Results

The results of the refined regional haze analysis are presented in Table 7-5. The results indicate that the proposed Project's maximum predicted impact on visibility at the Everglades NP is 4.90 percent for the combined-cycle operation on fuel oil. The maximum predicted impact on visibility when firing natural gas is 1.91 percent. The values are below the FLM's screening criteria of 5 percent change. Therefore, the Project is not expected to have an adverse impact on the existing regional haze in the Everglades NP.

7.4.3 SULFUR AND NITROGEN DEPOSITION

General Methods

As part of the AQRV analyses, total nitrogen (N) and sulfur (S) deposition rates were predicted at the Everglades NP Class I area. The deposition analysis thresholds (DAT) are based on the annual averaging period. The total deposition is estimated in units of kilogram per hectare per year (kg/ha/yr) of nitrogen or sulfur. The CALPUFF model is used to predict wet and dry deposition fluxes of various oxides of these elements.

For N deposition, the species include:

- Particulate ammonium nitrate (from species NO_3), wet and dry deposition;
- Nitric acid (species HNO_3), wet and dry deposition;
- NO_x, dry deposition; and
- Ammonium sulfate (species SO_4), wet and dry deposition.

For S deposition, the species include:

- $SO2$, wet and dry deposition; and
- $SO4$, wet and dry deposition.

The CALPUFF model produces results in units of $\mu g/m^2/s$. The modeled deposition rates are then converted to N or S deposition in kg/ha respectively, by using a multiplier equal to the ratio of the molecular weights of the substances (IWAQM Phase II report Section 3.3).

Deposition analysis thresholds (DAT) for nitrogen and sulfur deposition of 0.01 kg/ha/yr were provided by the U.S. Fish and Wildlife Service (January 2002). A DAT is the additional amount of N or S deposition within a Class I area, below which estimated impacts from a proposed new or modified source are considered insignificant. The maximum N and S depositions predicted for the Project are, therefore, compared to these DAT or significant impact levels.

Results

The maximum predicted N and S depositions predicted for the Project in the PSD Class I area of the Everglades NP are summarized in Table 7-6. The maximum N and S deposition rates for the Project are predicted to be 0.0015 and 0.0004 kg/ha/yr, respectively. These maximum deposition rates are below the significant impact levels for N and S of 0.01 kg/ha/yr. As a result, the Project's emissions are not expected to have a significant adverse effect on N and S deposition at the Class I area.

Table 7-5. Maximum 24-hour Average Visibility Impairment Predicted for the Project at the PSD Class I Area of the Everglades NP

Operating Mode	Maximum Visibility Impairment (%) [a]		Visibility Impairment Criteria (%)
	Natural Gas	Fuel Oil	
Combined-Cycle	1.91	4.90	5.0
Simple-Cycle (2 Units)	0.82	3.2	5.0

[a] Concentrations are highest predicted using CALPUFF model and 1990 CALMET wind field for south Florida. Background extinctions calculated using FLAG Document (December 2000) values and hourly relative humidity data.

[b] Concentrations predicted for combined- and simple cycle operation are based on the operating scenario with the maximum hourly emissions. For both natural gas- and oil-firing, maximum emissions are based on the combustion turbines operating for baseload conditions at an ambient temperature of 35°F.

For combined cycle operation and natural gas-firing, duct burner emission are included. For simple cycle operation and natural gas-firing, combustion turbines are assumed to operate at higher power mode.

Department of
Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

July 30, 2002

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

John M. Lindsay, Plant General Manager
Florida Power and Light Company
P.O. Box 176
Indiantown, FL 34956

Re: Project No. 0850001-010-AC
Air Permit No. PSD-FL-327
FPL Martin Power Plant
New 1150 MW Combined Cycle Unit 8

Dear Mr. Lindsay:

Florid Power and Light applied for a PSD air permit to construct an 1150 MW "4-on-1" combined cycle gas turbine unit at the existing FPL Martin Power Plant. Enclosed for this project is the Department's Intent to Issue Permit package, which includes the following: "Intent to Issue Air Construction Permit", "Public Notice of Intent to Issue Air Construction Permit", "Technical Evaluation and Preliminary Determination (draft BACT determinations), and the Draft Permit.

The Public Notice must be published one time only as soon as possible in a newspaper of general circulation in the area affected, pursuant to Chapter 50, Florida Statutes. Proof of publication, i.e., newspaper affidavit, must be provided to the Department's Bureau of Air Regulation office within seven (7) days of publication. Failure to publish the notice and provide proof of publication within the allotted time may result in the denial of the permit.

Please submit any other written comments you wish to have considered concerning the Department's proposed action to Al Linero, Manager of the New Source Review Section, at the above letterhead address. If you have any questions, please call Mr. Jeff Koerner at 850/921-9536 or Mr. Linero at 850/921-9523.

Sincerely,

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

CHF/AAL/jfk

Enclosures

SENDER: *COMPLETE THIS SECTION*

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Mr. John M. Lindsay
Plant General Manager
Florida Power & Light Company
Martin Power Plant
P.O. Box 176
Indiantown, FL 34956

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)*

B. Date of Delivery 7-12-02

C. Signature
X Charles Maloy ☒ Agent ☐ Addressee

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

Charles Maloy

3. Service Type
☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? *(Extra Fee)* ☐ Yes

2. Article Number 7001 0320 0001 3692 8376

PS Form 3811, July 1999 Domestic Return Receipt 102595-00-M-0952

U.S. Postal Service
CERTIFIED MAIL RECEIPT
(Domestic Mail Only; No Insurance Coverage Provided)

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Sent To
John M. Lindsay
Street, Apt. No.; or PO Box No.
PO Box 176
City, State, ZIP+4
Indiantown, FL 34956

PS Form 3800, January 2001 See Reverse for Instructions

In the Matter of an
Application for Permit by:

Florida Power and Light Company
P.O. Box 176
Indiantown, FL 34956

Authorized Representative:
Mr. John M. Lindsay, Plant General Manager

Project No. 0850001-010-AC
Draft Air Permit No. PSD-FL-327
FPL Martin Power Plant
New Combined Cycle Unit 8

INTENT TO ISSUE PSD PERMIT

The Department of Environmental Protection (Department) gives notice of its intent to issue a permit pursuant to the rules for the Prevention of Significant Deterioration of Air Quality (PSD), copy of DRAFT Permit attached, for the proposed project as detailed in the application specified above and the attached Technical Evaluation and Preliminary Determination for the reasons stated below.

The applicant, Florida Power and Light (FPL), applied on February 1, 2002 to the Department for a PSD permit for a 1150 MW combined cycle gas turbine project (Unit 8) at the FPL Martin Power Plant located approximately 7 miles north of Indiantown on State Road 710 in Martin County, Florida.

The Department has permitting jurisdiction under the provisions of Chapter 403, Florida Statutes (F.S.), Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210, and 62-212 and Code of Federal Regulations, 40 CFR 52.21. The above actions are not exempt from permitting procedures. The Department has determined that a PSD permit is required.

The Department intends to issue this air construction permit based on the belief that reasonable assurances have been provided to indicate that operation of these emission units will not adversely impact air quality, and the emission units will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296, 62-297, F.A.C. and 40 CFR 52.21.

Pursuant to Section 403.815, F.S., and Rule 62-110.106(7)(a)1., F.A.C., you (the applicant) are required to publish at your own expense the enclosed <u>Public Notice of Intent to Issue PSD Permit</u>. The notice shall be published one time only in the legal advertisement section of a newspaper of general circulation in the area affected. Rule 62-110.106(7)(b), F.A.C., requires that the applicant cause the notice to be published as soon as possible after notification by the Department of its intended action. For the purpose of these rules, "publication in a newspaper of general circulation in the area affected" means publication in a newspaper meeting the requirements of Sections 50.011 and 50.031, F.S., in the county where the activity is to take place. If you are uncertain that a newspaper meets these requirements, please contact the Department at the address or telephone number listed below. The applicant shall provide proof of publication to the Department's Bureau of Air Regulation, at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, Florida 32399-2400 (Telephone: 850/488-0114; Fax 850/ 922-6979). You must provide proof of publication within seven days of publication, pursuant to Rule 62-110.106(5), F.A.C. No permitting action for which published notice is required shall be granted until proof of publication of notice is made by furnishing a uniform affidavit in substantially the form prescribed in section 50.051, F.S. to the office of the Department issuing the permit. Failure to publish the notice and provide proof of publication may result in the denial of the permit pursuant to Rules 62-110.106(9) & (11), F.A.C.

The Department will issue the final permit with the attached conditions unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments and requests for public meetings concerning the proposed permit issuance action for a period of 30 (thirty) days from the date of publication of the enclosed <u>Public Notice</u>. Written comments should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below.

This PSD permitting action is being coordinated with a certification under the Power Plant Siting Act (Sections 403.501-519, F.S.). If a petition for an administrative hearing on the Department's Intent to Issue is filed by a substantially affected person, that hearing shall be consolidated with the certification hearing, as provided under Section 403.507(3).

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code.

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above. Mediation is not available in this proceeding.

In addition to the above, a person subject to regulation has a right to apply for a variance from or waiver of the requirements of particular rules, on certain conditions, under Section 120.542 F.S. The relief provided by this state statute applies only to state rules, not statutes, and not to any federal regulatory requirements. Applying for a variance or waiver does not substitute or extend the time for filing a petition for an administrative hearing or exercising any other right that a person may have in relation to the action proposed in this notice of intent.

The application for a variance or waiver is made by filing a petition with the Office of General Counsel of the Department, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000. The petition must specify the following information: (a) The name, address, and telephone number of the petitioner; (b) The name, address, and telephone number of the attorney or qualified representative of the petitioner, if any; (c) Each rule or portion of a rule from which a variance or waiver is requested; (d) The citation to the statute underlying (implemented by) the rule identified in (c) above; (e) The type of action requested; (f) The specific facts that would justify a variance or waiver for the petitioner; (g) The reason why the variance or waiver would serve the purposes of the underlying statute (implemented by the rule); and (h) A statement whether the variance or waiver is permanent or temporary and, if temporary, a statement of the dates showing the duration of the variance or waiver requested.

The Department will grant a variance or waiver when the petition demonstrates both that the application of the rule would create a substantial hardship or violate principles of fairness, as each of those terms is defined in Section 120.542(2) F.S., and that the purpose of the underlying statute will be or has been achieved by other means by the petitioner.

Persons subject to regulation pursuant to any federally delegated or approved air program should be aware that Florida is specifically not authorized to issue variances or waivers from any requirements of any such federally delegated or approved program. The requirements of the program remain fully enforceable by the Administrator of the EPA and by any person under the Clean Air Act unless and until the Administrator separately approves any variance or waiver in accordance with the procedures of the federal program.

Executed in Tallahassee, Florida.

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

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Intent to Issue Air Construction Permit (including the Public Notice, Technical Evaluation and Preliminary Determination, Draft BACT Determination, and the DRAFT permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 7/31/02 to the persons listed:

Mr. John M. Lindsay, FPL*
Mr. K. H. Simmons, FPL
Mr. Willie Welch, FPL
Mr. Ken Kosky, Golder Associates Inc.
Mr. Tom Tittle, SED
Mr. Gregg Worley, EPA Region 4
Mr. John Bunyak, NPS
Mr. Buck Oven, DEP Siting

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.

Victoria Gibson July 31, 2002
(Clerk) (Date)

PUBLIC NOTICE OF INTENT TO ISSUE PSD PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

Draft Permit No. PSD-FL-327

FPL Martin Power Plant, New Combined Cycle Unit 8
Martin County

The Department of Environmental Protection (Department) gives notice of its intent to issue a permit under the requirements for the Prevention of Significant Deterioration (PSD) of Air Quality to the Florida Power and Light Company. The permit is one of several authorizations needed to construct a nominal 1150 MW combined cycle gas project at the FPL Martin Power Plant, which is located approximately 7 miles north of Indiantown on State Road 710 in Martin County, Florida. In accordance with Rule 62-212.400, F.A.C. and 40 CFR 52.21, Best Available Control Technology (BACT) determinations were required for emissions of carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), sulfuric acid mist (SAM), and volatile organic compounds (VOC). The applicant's authorized representative is Mr. John M. Lindsay, Plant General Manager. The applicant's address is FPL Martin Power Plant, P.O. Box 176, Indiantown, FL 34956.

The applicant proposes to construct a "4-on-1" combined cycle Unit 8 consisting of the following equipment and specifications: two existing 170 MW simple cycle gas turbine-electrical generator sets (8A and 8B), two new 170 MW gas turbine-electrical generator sets (8C and 8D), four gas-fired heat recovery steam generators (495 MMBtu/hour, LHV), a common steam-electrical generator (470 MW), two new gas-fired fuel heaters (22 MMBtu/hour, each), a cooling tower, and other associated support equipment. The gas turbines will be fired primarily with natural gas and up to 500 hours per year of very low sulfur distillate oil as a restricted alternate fuel. For the first year of operation, each gas turbine may operate in simple cycle mode for 3390 hours per year while the combined cycle components are constructed. Once combined cycle operation is established, simple cycle operation is limited to an average of 1000 hours per year. Additional equipment includes four 120-foot stacks combined cycle stacks, four 80-foot simple cycle stacks, and an aqueous ammonia storage tank.

During simple cycle operation and gas firing, NOx emissions will be controlled by dry low-NOx combustion technology. During simple cycle operation and oil firing, NOx emissions will be controlled by wet injection techniques. During the predominant combined cycle operation, a selective catalytic reduction (SCR) system with ammonia injection will be used in conjunction with dry low-NOx combustion (gas firing) and wet injection (oil firing) to further reduce NOx emissions. To meet peak power demands, the following alternate methods of operation will be authorized: high-temperature peaking (60 hours/year for simple cycle and 400 hours/year for combined cycle operation); steam injection for power augmentation (400 hours/year); and duct burning (2880 hours/year). During these restricted alternate methods of operation, NOx emissions are slightly higher. Emissions of CO, PM/PM_{10}, SAM, SO_2, and VOC will be minimized by the efficient, high-temperature combustion of very low sulfur fuels (natural gas and distillate oil). Emissions of CO and NOx will be continuously monitored to demonstrate compliance with the conditions of the permit. The Department determines that these control techniques and equipment represent the Best Available Control Technology (BACT) in accordance with Rule 62-212.400, F.A.C. and 40 CFR 52.21. Emissions standards are presented in the draft permit on file with the Department.

Based on the initial application, the maximum potential annual emissions from the combined cycle gas turbines, the gas fired-fuel heaters, and the cooling tower that comprise new Unit 8 are summarized in the following table. It is noted that some of the annual emissions estimates will be less because of lower standards specified in the DRAFT permit.

Pollutant	Maximum Tons Per Year	PSD Significant Emission Rate Tons Per Year	PSD Review Required?
CO	826	100	Yes
Pb	0.025	0.6	No
NOx	683	40	Yes
PM/PM_{10}	322/275	15/25	Yes
SO_2	280	40	Yes
SAM	30	7	Yes
VOC	110	40	Yes

According to the applicant, maximum predicted air quality impacts due to emissions from the proposed new project are less than the applicable PSD Class II significant impact levels, with the exception of 24-hour SO_2 impacts Therefore, multi-

Notice for Newspaper

source modeling was only required for the 24-hour SO_2 impacts. The predicted impacts in the Everglades National Park are less than the applicable PSD Class I significant impact levels except for the 24-hour SO_2 impacts; therefore, multi-source Class I PSD increment modeling was only required for the 24-hour SO_2 impacts. The following table summarizes the maximum predicted PSD Class I and II 24-hour SO_2 increment consumed by the new project and by all increment-consuming sources.

Area and Averaging Time	Increment Consumed Project/All Sources (SO_2, ug/m^3)	Allowable Increment All Sources (SO_2, ug/m^3)	Increment Consumed Project/All Sources (Percent)
Class I, 24-hour (Everglades National Park)	0.4/3.5	5	8/70
Class II, 24-hour (Vicinity of Plant)	9/41	91	10/45

Based on the required analyses, the Department has reasonable assurance that the proposed project will not cause or significantly contribute to a violation of any ambient air quality standard or PSD increment. The Department will issue the FINAL Permit, in accordance with the conditions of the DRAFT Permit, unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments and requests for a public meeting concerning the proposed permit issuance action for a period of 30 (thirty) days from the date of publication of this Public Notice of Intent to Issue PSD Permit. Written comments or requests for public meetings should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below. This PSD permitting action is being coordinated with a certification under the Power Plant Siting Act (Sections 403.501-519, F.S.). If a petition for an administrative hearing on the Department's Intent to Issue is filed by a substantially affected person, that hearing shall be consolidated with the certification hearing, as provided under Section 403.507(3). Mediation is not available in this proceeding.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code.

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C. Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

A complete project file is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at:

Department of Environmental Protection
Bureau of Air Regulation
111 S. Magnolia Drive, Suite 4
(Mailing Address: 2600 Blair Stone Road, MS #5505)
Tallahassee, Florida 32399-2400
Telephone: 850/488-0114
Fax: 850/922-6979

Department of Environmental Protection
Southeast District Office
400 North Congress Avenue
(Mailing Address: P.O. Box 15425)
West Palm Beach, FL 33416-5425
Telephone: 561/681-6600
Fax: 561/681-6790

The complete project file includes the application, technical evaluations, Draft Permit, and the information submitted by the authorized representative, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Manager of the New Resource Review Section at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114 for additional information. The draft permit, technical evaluation and preliminary BACT determination can be accessed at www.dep.state.fl.us/air/permitting/construct.htm.

Notice for Newspaper

TECHNICAL EVALUATION
&
PRELIMINARY DETERMINATION
(DRAFT BACT DETERMINATIONS)

PROJECT

FPL Martin Power Plant
Unit 8 Combined Cycle Project

Project No. 0850001-010-AC
Draft Permit No. PSD-FL-327

COUNTY

Martin County

APPLICANT

Florida Power and Light
P.O. Box 176
Indiantown, FL 34956

PERMITTING AUTHORITY

Florida Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation
New Source Review Section

July 30, 2002

Filename: 327 TEPD.doc

TABLE OF CONTENTS

This document describes the overall project, identifies applicable air pollution regulations, provides the rationale for draft determinations of the Best Available Control Technology, establishes emissions standards, presents a review of the air quality impact analysis, and makes a preliminary determination to issue the air permit. It is organized by the following sections.

1. APPLICATION INFORMATION

Applicant Name and Address

Florida Power and Light Company
P.O. Box 176
Indiantown, FL 34956

Authorized Representative:
John M. Lindsay, Plant General Manager

Processing Schedule

- Received application on February 1, 2002;
- Additional information requested on March 1, 2002;
- Received additional information on May 6, 2002; application deemed complete.

Facility Description and Location

Florida Power and Light (FPL) operates the Martin Power Plant, which is located approximately 7 miles north of Indiantown on State Road 710 and east of Lake Okeechobee in Martin County, Florida. The existing plant currently has a total electrical generating capacity of approximately 3066 MW. Units 1 and 2 are fossil fuel-fired steam electric generators with a capacity of 863 MW each. Units 3A, 3B, 4A, and 4B are combined cycle units consisting of 170 MW gas turbines matched with heat recovery steam generators (HRSGs). Each pair of gas turbines (3A/3B and 4A/4B) provides steam to a common steam-electrical turbine (160 MW each). Units 8A and 8B are 170 MW simple cycle gas turbines.

Regulatory Categories

Title III: The facility is a major source of hazardous air pollutants (HAPs). Based on the available information, this project does not trigger the requirements for a case-by-case 112(g) determination of the Maximum Available Control Technology (MACT).

Title IV: The facility operates units subject to the Acid Rain provisions of the Clean Air Act.

Title V: The facility is a Title V major source of air pollution because the potential emissions of at least one regulated pollutant exceed 100 tons per year. Regulated pollutants include pollutants such as carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), and volatile organic compounds (VOC).

PSD: The facility is located in an area that is in attainment with, or designated as unclassifiable for, each pollutant subject to a National Ambient Air Quality Standard. It is classified as a fossil fuel-fired steam electric plant, which is one of the 28 PSD Major Facility Categories identified in Table 62-212.400-1, F.A.C. Emissions from the facility are greater than 100 tons per year for at least one regulated pollutant. Therefore, the facility is "major" with respect to Rule 62-212.400, F.A.C. for the Prevention of Significant Deterioration (PSD) of Air Quality.

Siting: The facility is a steam electrical generating plant. The project will result in more than 75 MW of steam-generated electrical power and is subject to the power plant siting provisions of Chapter 62-17, F.A.C.

2. PROPOSED PROJECT

Project Description

The applicant proposes to construct a "4-on-1" combined cycle Unit 8 consisting of the following equipment and specifications: two existing 170 MW simple cycle gas turbine-electrical generator sets (8A and 8B), two new 170 MW gas turbine-electrical generator sets (8C and 8D), four gas-fired heat recovery steam generators (495 MMBtu/hour, LHV), a common steam-electrical generator (470 MW), two new gas-fired fuel heaters (22 MMBtu/hour, each), a cooling tower, and other associated support equipment.

Gas Turbine/HRSG Units: Each gas turbine/HRSG unit consists of a nominal 170 MW General Electric Model PG7241(FA) gas turbine-electrical generator set, an automated gas turbine control system, an inlet air filtration system, an evaporative inlet air-cooling system, and a gas-fired heat recovery steam generator (HRSG). The project utilizes two existing 170 MW gas turbines (Units 8A and 8B) that are currently permitted for simple cycle only operation. The project adds two new 170 MW gas turbines (8C and 8D).

Fuels: Each gas turbine will fire natural gas as the primary fuel and distillate oil as a restricted alternate fuel. Emissions of all pollutants increase with the firing of oil. The applicant requests 500 hours per year per gas turbine (or equivalent) for oil firing.

Generating Capacity: Each of the four gas turbines has a nominal generating capacity of 170 MW for gas firing (180 MW for oil firing). Each of the four heat recovery steam generators (HRSGs) provides steam to the single steam turbine electrical generator, which has a nominal capacity of 470 MW. The total nominal generating capacity of the "4-on-1" combined cycle unit is 1150 MW.

Controls: CO, PM/PM_{10}, and VOC will be minimized by the efficient combustion of natural gas and distillate oil at high temperatures. Emissions of SAM and SO_2 will be minimized by firing natural gas and restricting the amounts of very low sulfur distillate oil. NOx emissions will be reduced with dry low-NOx (DLN) combustion technology for gas firing and water injection for oil firing. In combination with these NOx controls, a selective catalytic reduction (SCR) system further reduces NOx emissions during combined cycle operation.

Continuous Monitors: Each gas turbine is required to continuously monitor NOx emissions in accordance with the acid rain provisions. Flue gas oxygen content or carbon dioxide content will be monitored as a diluent gas.

Stack Parameters: Each gas turbine has a simple cycle (or bypass) stack that is 80 feet tall and 22.0 feet in diameter. Each heat recovery steam generator has a combined cycle stack (HRSG stack) that is 120 feet tall and 19.0 feet in diameter. The following summarizes the exhaust characteristics:

			Simple Cycle Operation		Combined Cycle Operation	
Fuel	Heat Input Rate	Compressor Inlet Temp.	Exhaust Temp.	Flow Rate ACFM	Exhaust Temp., °F	Flow Rate ACFM
Gas	1600 MMBtu/hour	59° F	1116° F	2,389,500	202° F	1,004,200
Oil	1811 MMBtu/hour	59° F	1098° F	2,735,300	295° F	1,193,900

Operating Modes: Each gas turbine may operate in simple cycle mode (without the HRSG) to produce only shaft-driven electrical power with hot exhaust through the bypass stack. This mode is typically reserved for meeting peak energy demand periods because it is much less efficient. Operation in combined cycle mode recovers heat energy from the HRSG in the form of steam, which is delivered to the steam-electrical turbine to produce steam-generated electrical power. For the first year of operation, the applicant requests 3390 hours per year per gas turbine of simple cycle operation until the combined cycle unit is complete. Once combined cycle operation is established, the applicant requests an average of 1000 hours per year for the combination of four gas turbines. The applicant has also requested the following additional modes of operation.

- Fogging: Evaporative cooling (also known as "fogging") is the injection of fine water droplets into the gas turbine compressor inlet air, which reduces the gas temperature through evaporative cooling. Lower compressor inlet temperatures result in a more mass flow rate through the gas turbine with a boost in shaft-driven electrical power production. The emissions performance remains within the normal profile of the gas turbine for the lower compressor inlet temperatures. Fogging may occur during simple or combined cycle operation and no restrictions are requested. Fogging will be implemented at ambient temperatures of 60° F or higher.
- Duct Burning: During combined cycle operation, duct burners in the HRSG may be fired with natural gas to raise the useful heat energy of the gas turbine exhaust and produce additional steam-generated electricity. Although the overall cycle of the unit is less efficient in this mode, duct firing is useful during periods of high-energy demand. Duct firing may result in increased mass emissions rates due to the increased fuel consumption. The applicant requests 2880 hours of duct burning per year for each gas unit.
- Power Augmentation: Power augmentation is the injection of steam into the gas turbine compressor, which results in a higher mass flow rate through the gas turbine and provides a slight increase in shaft-driven electrical power production. Power augmentation is used at loads above 95% of base load and may be used alone or in combination with duct burning. Steam injection may cause some increase in emissions of carbon monoxide. The applicant requests 400 hours per year per gas turbine of power augmentation.
- Peaking: Peaking allows gas turbine temperatures to drift higher than normal and results in increased in shaft-driven electrical power production. Peaking is expected to increase NOx emissions from the gas turbine due to higher temperatures. During combined cycle operation, NOx emissions would be reduced to allowable levels with SCR. For each gas turbine, the applicant requests operation in the peaking mode up to 60 hours per year for simple cycle operation and 400 hours per year for combined cycle operation.

The restrictions identified above are included as limitations in the draft permit.

Potential Emissions

The project will result in emissions of carbon monoxide (CO), lead (Pb), nitrogen oxides (NOx), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), sulfuric acid mist (SAM), and volatile organic compounds. The following table summarizes the applicant's estimate of the annual emissions in tons per year from the proposed project (gas turbines, duct burners, gas-fired fuel heaters, and cooling tower).

Table 2-1. Applicant's Estimated Annual Emissions

Pollutant	Project Emissions, TPY		Maximum, TPY	PSD Significant Emission Rate, TPY	PSD Review Required?
	1st Year	2nd Year			
CO	228	826	826	100	Yes
Pb	0.025	0.025	0.025	0.6	No
NOx	664	683	683	40	Yes
PM/PM_{10}	69/69	322/275	322/275	15/25	Yes
SO_2	156	280	280	40	Yes
SAM	16	30	30	7	Yes
VOC	23	110	110	40	Yes

Based on the applicant's estimates, the project requires the determinations of the Best Available Control Technology (BACT) for emissions of CO, NOx, PM/PM_{10}, SO_2, SAM, and VOC.

3. RULE APPLICABILITY

State Regulations

The project is subject to the applicable environmental laws specified in Section 403 of the Florida Statutes (F.S.). The Florida Statutes authorize the Department of Environmental Protection to establish rules and regulations regarding air quality as part of the Florida Administrative Code (F.A.C.). This project is subject to the following state rules and regulations of the Florida Administrative Code.

Chapter	**Description**
62-4	Permitting Requirements
62-17	Electrical Power Plant Siting
62-204	State Implementation Plan (AAQS, PSD Increments, and adoption of Federal Regulations)
62-210	Stationary Sources of Air Pollution – General Requirements
62-212	Preconstruction Review (including PSD Requirements)
62-213	Operation Permits for Major Sources of Air Pollution
62-214	Acid Rain Program Requirements
62-296	Emission Limiting Standards
62-297	Emissions Monitoring

Federal Regulations

This project is also subject to the applicable federal provisions regarding air quality as established by the EPA in the Code of Federal Regulations (CFR) and summarized below.

Title 40	**Description**
Part 51	Submittal of Implementation Plans – PSD
Part 52	Approval of Implementation Plans – PSD
Part 60	New Source Performance Standards (NSPS)
Part 72	Acid Rain - Permits Regulation
Part 73	Acid Rain - Sulfur Dioxide Allowance System
Part 75	Acid Rain - Continuous Emissions Monitoring
Part 76	Acid Rain - Nitrogen Oxides Emissions Reduction Program
Part 77	Acid Rain - Excess Emissions

Note: Acid rain requirements will be included in the Title V air operation permit.

Description of PSD Applicability Requirements

The Department regulates major air pollution sources in accordance with Florida's Prevention of Significant Deterioration (PSD) program, as defined in Rule 62-212.400, F.A.C. and approved by EPA in the State Implementation Plan. A PSD review is only required in areas that are currently in attainment with the National Ambient Air Quality Standard (AAQS) for a given pollutant or areas designated as "unclassifiable" for the pollutant. A new facility is considered "major" with respect to PSD if the facility emits or has the potential to emit:

- 250 tons per year or more of any regulated air pollutant, or
- 100 tons per year or more of any regulated air pollutant and the facility belongs to one of the 28 Major Facility Categories (Table 62-212.400-1, F.A.C.), or
- 5 tons per year of lead.

For new projects at existing PSD-major sources, each regulated pollutant is reviewed for PSD applicability based on emissions thresholds known as the Significant Emission Rates listed in Table 62-212.400-2, F.A.C. Project emissions exceeding these rates are considered "significant". For each significant pollutant, the applicant must employ the Best Available Control Technology (BACT) to minimize emissions and conduct an appropriate ambient impact analyses. Although a facility may be "major" with respect to PSD for only one regulated pollutant, it may be required to install BACT controls for several significant regulated pollutants.

Note: This project is reviewed in accordance with the federally delegated PSD program because it is subject to electrical power plant site certification.

Description of PSD Preconstruction Review Requirements

PSD preconstruction review consists of two parts. The first part requires the Department to establish the Best Available Control Technology (BACT) for each pollutant emitted in excess of a PSD Significant Emission Rate. The applicant reviews current control technologies and techniques for similar projects and proposes control options and emissions standards for the project. The Department reviews the information provided by the applicant with all other available information and makes a determination of the Best Available Control Technology (BACT) for each "significant" regulated pollutant. The BACT determination must be based on the maximum degree of emissions reduction that the Department determines is achievable through application of production processes and available methods, systems, and techniques for control of each such pollutant. The Department's determination is made on a case-by-case basis for each proposed project, taking into account energy, environmental and economic impacts. The Department shall also give consideration to:

- Any EPA determination of BACT pursuant to Section 169 of the Clean Air Act, and any emission limitation contained in 40 CFR Part 60 (NSPS) or 40 CFR Part 61 (NESHAP).
- All scientific, engineering, and technical material and other information available to the Department.
- The emission limiting standards or BACT determinations of any other state.
- The social and economic impacts of the application of such technology.

The EPA currently directs that BACT should be determined using the "top-down" approach. In this approach, available control technologies are ranked in order of control effectiveness for the emissions unit under review. The most stringent control option is evaluated first and selected as BACT unless it is technically infeasible for the proposed project or rejected due to adverse energy, environmental or economic impacts. If the control option is eliminated, the next most stringent alternative is considered. This top-down approach continues until BACT is determined.

The BACT evaluation must be performed for each emissions unit and pollutant under consideration. BACT determinations must result in the selection of control technologies capable of achieving at least the applicable emission standards specified in 40 CFR Part 60 (NSPS) or 40 CFR Part 61 (NESHAP). When reviewing control technologies for regulated pollutants, the Department will favorably consider the control or reduction of other "non-regulated" air pollutants in determining BACT. The Department will also favorably consider control technologies that utilize pollution prevention. These approaches are consistent with EPA's consideration of environmental impacts and strategies for pollution prevention.

The second part of PSD review requires an Air Quality Analysis consisting of: an air dispersion modeling analysis to estimate the resulting ambient air pollutant concentrations; a comparison of modeled concentrations from the project with National Ambient Air Quality Standards and PSD Increments; an analysis of the air quality impacts from the proposed project upon soils, vegetation, wildlife, and visibility; and an evaluation of the air quality impacts resulting from associated commercial, residential, and industrial growth related to the proposed project. The applicant must satisfactorily demonstrate that potential project emissions will not significantly contribute to or cause a violation of any ambient air quality standards and will not adversely impact Class I and Class II Areas.

4. AVAILABLE INFORMATION

In addition to the information submitted by the applicant, the Department also relied on the following available information to make these determinations:

- DOE web site information on Advanced Turbine Systems Project;
- Test data for various similar projects including the City of Tallahassee's Purdom Generating Station and Gulf Power's Lansing Smith Plant;
- General Electric technical documents regarding the Model PG7241(FA) gas turbine, the DLN "hot nozzle" combustor, the gas turbine control system, and the startup/shutdown data;
- EPA's Alternative Control Techniques Document: NOx Emissions from Stationary Gas Turbines (1993);
- U. S. Department of Energy Report (11/05/99) titled, "Cost Analysis of NOx Control Alternatives for Stationary Gas Turbines" prepared by Onsite Sycom Energy Corporation;
- Onsite Sycom Energy Corporation's report titled "Cost Analysis of NOx Control Alternatives for Stationary Gas Turbines" (1999) prepared for the U.S. Department of Energy
- AP-42, Section 3.1 for gas turbines (04/00);
- EPA memorandums regarding gas turbines and MACT applicability dated 12/30/99 and 08/21/01; and
- Recently issued permits for the General Electric Model PG7241(FA) gas turbine.

The Department also reviewed recent BACT determinations posted in EPA's RACT/BACT/LAER Clearinghouse. A list of recent BACT determinations regarding similar projects in Florida and the Southeastern United States is provided in See Attachment A.

5. DRAFT BACT STANDARDS – NITROGEN OXIDES

Discussion of NOx Emissions

A gas turbine is sometimes referred to a "heat engine". In operation, air is compressed, combusted with fuel to produce hot exhaust gases (≈ 2350° F), and expanded in the turbine section to drive a shaft to produce useful energy. The majority of the energy produced is returned to the compressor and other supporting equipment. The remainder can be used to drive an electrical generator to produce electricity. This power cycle is known as the Brayton cycle and is commonly referred to as the "simple cycle mode of operation". A heat recovery steam generator may be added to convert the remaining heat energy of the exhaust gases into steam to drive a steam-electric turbine to produce additional electricity. This additional power cycle is known as the Rankine cycle. Gas turbines with heat recovery steam generators are commonly referred to as combined cycle units.

For gas turbines, the primary pollutant of concern is nitrogen oxides (NOx) due to the high temperatures. Nearly all of the NOx is emitted as nitric oxide (NO), which is readily oxidized in the exhaust system or the atmosphere to the more stable NO_2 molecule (nitrogen dioxide). NOx forms from the dissociation of molecular nitrogen and oxygen into their atomic forms and subsequent recombination into seven different oxides of nitrogen. Three primary mechanisms cause NOx emissions:

- *Thermal NOx* forms in the high temperature area of the gas turbine combustor. It 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. Less NOx is formed during lean combustion (low fuel-to-air ratio) because the flame temperature is lower.
- *Prompt NOx* is formed in the proximity of the flame front as intermediate combustion products. The contribution of prompt NOx to overall NOx emissions is relatively small in combustors that operate near the stoichiometric air-to-fuel ratio. However, new combustors that operate in lean premix mode generate far less thermal NOx, which makes prompt NOx a greater contributor to overall NOx emissions for these types of units. Therefore, prompt NOx may provide a practical limit for NOx control by lean combustion.
- *Fuel NOx* forms from the oxidation of nitrogen in the fuel. This phenomenon is not important when combusting natural gas or distillate oil fuels, which contain negligible fuel-bound nitrogen (FBN).

Uncontrolled NOx emissions from gas turbines may range as high as 600 parts per million by volume, dry, corrected to 15 percent oxygen. The federal New Source Performance Standards (40 CFR 60, Subpart GG) regulate NOx emissions from large utility gas turbines to 75 ppmvd corrected to 15% oxygen and ISO conditions, which can then be adjusted for the fuel-bound nitrogen content and heat rate of the given unit.

<u>Descriptions of Available NOx Controls</u>

The following technologies were identified as potentially applicable for the control of NOx from gas turbines. A brief description of each technology is included with an estimated control efficiency based on an uncontrolled conventional gas turbine with NOx emissions of 150 ppmvd corrected to 15% oxygen.

Lean Premix (LPM) Combustor Design: Efforts over the last ten years to minimize NOx emissions from gas turbines have focused on reducing the peak flame temperature for natural gas fired units by staging combustors and premixing fuel and air prior to combustion in the primary zone. General Electric's version of the lean premix combustor design is called dry low-NOx (DLN) combustion. The following is a general description of the typical air/fuel combustion modes used to achieve lean premix combustion. In the primary mode, fuel is supplied only to the primary (diffusion) nozzle to ignite, accelerate, and operate the unit over a range of low-load to mid-load operation and up to a given combustion reference temperature. Once the first combustion reference temperature is reached, operation in a lean-lean mode begins when fuel is also introduced to the secondary nozzles to achieve the second combustion reference temperature. After the second combustion reference temperature is reached, operation in a secondary mode begins by shutting off fuel to the primary nozzle and extinguishing the flame in the primary zone. Finally, in the lean premix mode, fuel is reintroduced to the primary zone for premixing fuel and air. Although fuel is supplied to both the primary and secondary nozzles in the premix mode, there is only flame in the secondary stage. Other manufacturer's models maintain the primary diffusion nozzle, which leads to slightly higher NOx emissions.

Figure 5-1 represents the fuel nozzle arrangement of the General Electric DLN-2.6 can-annular combustor, which is the technology specified for proposed project. With this design, each combustor includes six nozzles within which fuel and air are fully pre-mixed. There are 16 small fuel passages around the circumference of each combustor can known as quaternary fuel pegs. The six nozzles are sequentially ignited as load increases in a manner that maintains lean pre-mixed combustion and flame stability.

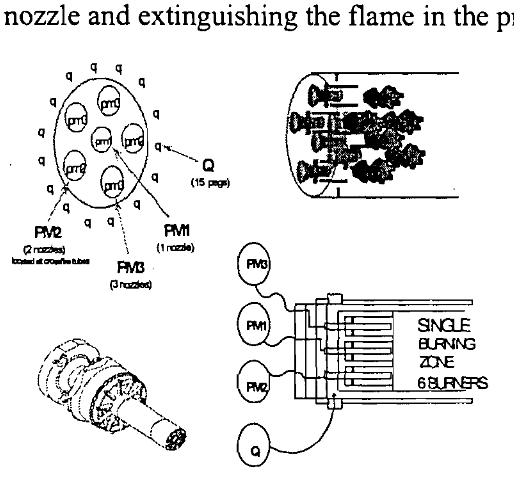


Figure 5-1. GE's DLN 2.6 Combustor

The full lean premix mode of operation typically occurs between 50% and 70% of base load and provides the lowest NOx emissions. Due to the intricate air and fuel staging necessary for lean premix combustion, the automated gas turbine control system becomes a critical component of the overall system. Although research for oil firing continues, lean premix combustion technology is currently only effective for firing natural gas. Dual fuel combustors must also employ wet injection to reduce NOx emissions when firing oil.

General Electric currently guarantees a NOx level of 9 ppmvd corrected to 15% oxygen for the Frame 7FA series of gas turbines. This low NOx emission rate is achieved while also minimizing CO emissions below 9 ppmvd. There are numerous projects installed and currently under construction with General Electric's dry low-NOx combustion technology. The following tables presents test results for a "new and clean" 7FA gas turbine firing natural gas in combined cycle mode without add on NOx controls.

Table 5-1. Test Results for GE 7FA Gas Turbine, City of Tallahassee's Purdom Station

Percent of Full Load	NOx, ppmvd @15% O_2	CO, ppmvd
70	7.2	ND
80	6.1	ND
90	6.6	ND
100	8.7	0.85

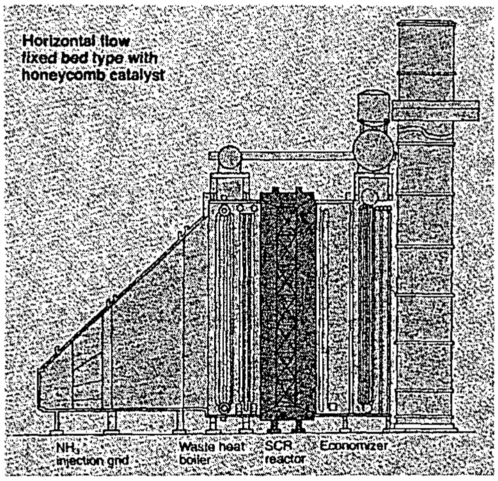
Table 5-2. Test Results for GE 7FA Gas Turbine, TECO Polk Power Station

Percent of Full Load	NOx, ppmvd @15% O_2	CO, ppmvd	VOC, ppmvd
50	5.3	1.6	0.5
70	6.3	0.5	0.4
85	6.2	0.4	0.2
100	7.6	0.3	0.1

These test results confirm NOx emission levels below the manufacturer's emissions guarantee. Recent conversations with other operators indicate that the lean premix emission characteristics also extend to operations less than 50 percent of full load, though such operation is not (yet) guaranteed by GE. Lean premix combustion technology results in control efficiencies approaching 95%.

Wet Injection (WI): Water or steam is injected into the primary combustion zone to reduce the flame temperature, resulting in lower NOx emissions. Water injected into this zone acts as a heat sink by absorbing heat necessary to vaporize the water and raise the temperature of the vaporized water to the temperature of the exhaust gas stream. Steam injection uses the same principle, excluding the heat required to vaporize the water. Therefore, much more steam is required (on a mass basis) than water to achieve the same level of NOx control. However, there is a physical limit to the amount of water or steam that may be injected before flame instability or cold spots in the combustion zone would cause adverse operating conditions for the combustion turbine. The New Source Performance Standards for gas turbines (40 CFR 60, Subpart GG) was developed around this technology in the late 1970's. Wet injection techniques are generally reserved for oil firing because advanced lean premix combustor designs can achieve much lower NOx emissions for gas firing without wet injection. However, for oil firing, the advanced dual fuel combustor designs can tolerate large amounts of steam or water without causing flame instability and can typically achieve NOx emissions of less than 42 ppmvd when combined with wet injection techniques. Therefore, wet injection remains a viable alternative when firing oil in modern dual fuel combustors. Wet injection results in control efficiencies approaching 75% for oil firing.

Selective Catalytic Reduction (SCR): This is an add-on control technology in which ammonia is injected into the exhaust gas stream in the presence of a catalyst bed to combine with NOx in a reduction reaction forming nitrogen and water. The figure below shows the general arrangement of the ammonia injection grid and SCR catalyst with respect to the heat recovery steam generator for a combined cycle unit. The exhaust gas temperature must be maintained between 450° F and 850° F for this reaction to proceed satisfactorily. For combined cycle gas turbines, the temperature is within the proper range and conventional catalysts such as vanadium or titanium oxide are acceptable. However, the exhaust from simple cycle gas turbines can exceed 1000° F and require more expensive high temperature zeolite catalysts and possibly additional gas cooling to protect the catalyst. Ammonia that escapes past the catalyst without reacting with NOx is called "ammonia slip". If the fuel contains significant amounts of sulfur, high levels of ammonia slip can lead to the formation of bisulfates and other particulate matter. Ammonia slip will gradually increase over the life of the system due to degradation of the catalyst. The catalyst is typically replaced every 5 to 7 years although vendors typically guarantee catalysts for about three years. SCR is a commercially available, demonstrated control technology currently employed on numerous combined cycle combustion turbine projects permitted with very low NOx emissions (< 2.5/10 ppmvd for gas/oil firing). There are a few "hot SCR" systems employed on smaller simple cycle units with slightly higher NOx emissions. SCR results in control efficiencies of approaching 98%.



SCONOx™: This technology is a NOx and CO control system developed by Goal Line Environmental Technologies and is distributed through Alstom Power for large gas turbine projects. Specialized potassium carbonate catalyst beds reduce NOx emissions using an oxidation-absorption-regeneration cycle. The required operating temperature range is between 300°F and 700°F, which is within the typical range of exhaust gas from heat recovery steam generator in a combined cycle gas turbine. SCONOx™ technology (at 2.0 ppmvd) has been used to define the Lowest Achievable Emission Rate (LAER) in non-attainment areas where cost is not a factor in establishing an emissions standard. SCONOx™ systems also oxidize emissions of CO and VOC for additional emission reductions. SCONOx™ can also achieve control efficiencies approaching 98% without the additional ammonia emissions associated with SCR.

XONON™: This is an emerging technology that partially burns fuel in a low-temperature pre-combustor and completes combustion in a catalytic combustor. The result is partial combustion with a lower temperature (and less NOx formation) followed by flameless catalytic combustion to further inhibit NOx formation. This technology has been demonstrated, but the design will be unique for each manufacturer and model of gas turbine. It is anticipated that control efficiencies may approach 98%.

Selective Non-Catalytic Reduction (SNCR): This technology works on the same principle as SCR, but in the absence of a catalyst. Ammonia (or urea) is injected directly into a hot gas stream (1400° F to 2000° F), which promotes the conversion of NOx to nitrogen and water given sufficient residence time. 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 NOx conversion mechanism. However, with a large duct burner in the heat recovery steam generator, it is possible to reach the exhaust gas temperatures that would make SNCR feasible.

<u>Applicant's NOx BACT Proposal – Combined Cycle Operation</u>

In addition to the dry low NOx (DLN) combustion technology for the specified gas turbine, the applicant identified the following add-on control technologies for reducing NOx emissions: NOxOut, Thermal DeNOx, NSCR, XONON™, wet injection, SCR, and SCONOx™ . Of these technologies, the applicant indicates that only DLN, wet injection, SCR, SCONOx™ , and XONON™ are feasible for the project. The applicant does not believe that XONON™ is yet available or demonstrated for an "F-class" gas turbine or that SCONOx™ has been demonstrated for such a unit. The applicant did review SCONOx™ as the top control technology, followed by SCR. These add-on controls would be in addition to DLN combustion for gas firing and wet injection for oil firing. The applicant noted the following adverse impacts with regard to SCONOx™ .

Energy Impacts: The pressure drop across the SCONOx™ system causes backpressure on the gas turbine, which can reduce power output. SCONOx™ also requires the use of natural gas and steam to regenerate the catalyst. The overall energy requirement is approximately equivalent to 34,800,00 kWh per year for each unit. The combined energy requirements in terms of natural gas usage would be 362 million cubic feet of natural gas per year, which is roughly 2.3% of the gas turbine heat input. The applicant believes that this is approximately 7 times that of SCR.

Environmental Impacts: Due to the backpressure and energy requirements for SCONOx™ noted above, the applicant estimates that such a system would increase criteria pollutants by 41 tons per year and carbon dioxide emissions by 23,000 tons per year for each gas turbine.

Economic Impacts: The applicant estimates that the installation of SCONOx™ to achieve a NOx standard of 2.5 ppmvd corrected to 15% oxygen for gas firing would result in estimated annualized costs of $5,682,000 per year and an overall cost effectiveness of $18,900 per ton of NOx removed. This compares to the applicant's estimated cost effectiveness of $4900 per tons of NOx removed for an SCR system at 2.5 ppmvd corrected to 15% oxygen.

The applicant rejects SCONOx™ based on the significant energy, environmental, and economic impacts. SCONOx™ and SCR are capable of achieving nearly the same level of NOx reduction. Although SCONOx™ achieves this level without additional emissions of ammonia, SCR systems can be designed and operated to minimize ammonia slip. The use of distillate oil for this project further complicates the SCONOx™ system and can cause premature fouling. It is possible that a SCOSOx™ catalyst could be added to reduce SO_2 emissions. The applicant believes that the energy and environmental disadvantages of a SCONOx™ system outweigh the any potential additional reductions in NOx. The applicant requests the following NOx standards as BACT for combined cycle operation.

a. Oil Firing: 12 ppmvd @ 15% O_2, 24-hour average

b. Gas Firing: 2.5 ppmvd @ 15% O_2, 24-hour average

{Note: These limits represent approximately a 70% reduction from gas firing with DLN combustion (9 ppmvd @ 15% O_2) and oil firing with wet injection (42 ppmvd @ 15% O_2).}

Department's Draft BACT Determinations – Combined Cycle Operation

The Department also ranks SCONOx™ and SCR as the top add-on control technologies for combined cycle operation. SCONOx™ has been demonstrated on small units in California and has been purchased for a small source in Massachusetts. California regulators and have permitted the La Paloma Plant near Bakersfield for the installation of one 250 MW block with SCONOx™. The overall project includes several more 250 MW blocks with SCR for control. According to industry sources, the installation has proceeded with a standard SCR due to schedule constraints. Recently, PG&E Generating has been approved to install SCONOx™ on two "F" class units at Otay Mesa, approximately 15 miles S.E. of San Diego, California. Additionally, EPA 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 a SCONOx™ system. SCONOx™ has not been applied on any major sources in ozone attainment areas, apparently due to cost considerations. The Department is interested in seeing this ammonia-free emissions technology demonstrated on a large "F" class unit. The Department offers the following comments regarding the applicant's discussion of the additional adverse impacts.

- The pressure drop across the SCONOx™ system may be greater than that of SCR.

- The energy losses described are relatively small and would occur on a day-to-day basis. The applicant's estimates of additional emissions assumes that the replacement energy would be needed each and every day, 24 hours a day.
- The Department does not endorse the applicant's estimate of the cost effectiveness for either SCONOx™ or SCR. However, the estimates appear to at the high end of the range of estimates for other similar projects. It is unlikely that SCONOx™ would be cost effective at even half of the estimated cost.

The Department rejects SCONOx™ primarily as not being cost effective and accepts conventional SCR as the Best Available Control Technology. The Department establishes the following draft BACT standards for combined cycle operation.

a. Oil Firing: 10 ppmvd @ 15% O_2, 24-hour average

b. Gas Firing: 2.5 ppmvd @ 15% O_2, 24-hour average

These determinations are consistent with recent determinations for combined cycle gas turbine projects in attainment areas. See Attachment A. The above standards include any emissions resulting from duct burning. In at least four previous BACT determinations, the Department specified NOx BACT of 10 ppmvd @ 15% O_2 for Frame 7 combined cycle gas turbines with conventional SCR. Compliance with the standards will be demonstrated by continuous emissions monitoring system (CEMS). The Department also notes that other similar combined cycle projects in Maine and Washington received BACT limits of 2.0 ppmvd @ 15% O_2 for gas firing with SCR. However, the Department's proposed BACT limit considers measurement uncertainties associated with very low emission rates and the proposed ammonia slip limit of 5 ppmvd @ 15% O_2. EPA Region 4 has commented that 2.5 ppmvd @ 15% O_2 represents the lowest BACT level in the region and that the 24-hour averaging period is acceptable in light of the low standard. The above limit is much more stringent than the NSPS Subpart GG standard for gas turbines.

Applicant's NOx BACT Proposal – Simple Cycle Operation

The applicant notes that the project is intended to be a base loaded 4-on-1 combined cycle unit. The ability to operate in simple cycle mode is desired to meet peak demands during the construction of the combined cycle units (up to 3390 hours per year per gas turbine). Simple cycle mode is also requested as a backup mode once the combined cycle project is complete (up to an average of 1000 hours per year per gas turbine). Due to the high exhaust temperatures of simple cycle operation, SCONOx™ is not technically feasible. The applicant does not believe that SCR using high temperature catalysts ("hot" SCR) is technically feasible or demonstrated for large "F-class" gas turbines. Noted is a determination by the Maryland Department of Environment that hot SCR was not LAER due to technical feasibility issues and collateral environmental impacts. EPA Region III concurred with the Maryland determination. However, the applicant reviewed hot SCR as the top control for simple cycle operation and noted the following adverse impacts from this technology.

Energy Impacts: The pressure drop across the hot SCR system will cause backpressure on the gas turbine, which can reduce power output by up to 0.5%. At 3390 hours per year, the lost energy is equivalent to about 320 residential customers per year or, in terms of natural gas usage, would be 37 million cubic feet of natural gas per year.

Environmental Impacts: The applicant comments that lost power due to backpressure would likely be replaced by older less efficient units with higher emissions. Due to the very low predicted ambient impacts from DLN combustion alone, the applicant does not believe that hot SCR would only have marginal overall air quality benefits given the proposed period of long-term operation (1000 hours per year per gas turbine).

Economic Impacts: The applicant estimates that the installation of hot SCR to achieve a NOx standard of 3.5/15 ppmvd corrected to 15% oxygen for gas/oil firing would result in estimated annualized costs of $1,728,800 per year and an overall cost effectiveness of $25,200 per ton of NOx removed assuming 3390 hours per year of operation. Assuming 1000 hours per year of operation increases the estimated cost effectiveness to $57,700.

The applicant rejects hot SCR based on the adverse energy, environmental, and economic impacts. The applicant considers hot SCR to be technically infeasible for the project because it has not yet been demonstrated on an "F" class dual fuel gas turbine. The applicant requests the following NOx standards as BACT for simple cycle operation.

a. Oil Firing: 42 ppmvd @ 15% O_2, 24-hour average
b. Gas Firing: 9.0 ppmvd @ 15% O_2, 24-hour average
c. Gas Firing w/Power Augmentation or Peaking: 15.0 ppmvd @ 15% O_2, 24-hour average

Department's Draft NOx BACT Determinations – Simple Cycle Operation

The Department also ranks hot SCR as the top add-on control technology. The catalyst will cause a small drop in pressure, which can reduce power output. Examples of this technology is the Carson Plant in Sacramento, California (GE LM6000-PA, < 50 MW) and the proposed new unit for the Sacramento Municipal Utilities District (GE 7EA, 75MW), which were determinations of the Lowest Achievable Emission rate (LAER) for a nonattainment area. The Department offers the following comments regarding the applicant's discussion of the additional adverse impacts.

- It is noted that ambient impacts are reviewed separately from the determination of BACT controls.
- Although the Department does not endorse the applicant's estimate of the cost effectiveness for hot SCR, it does believe that this technology is not cost effective for the limited operation expected.

The Department rejects hot SCR primarily based on costs and accepts dry low-NOx combustion for gas firing and wet injection for oil firing as the Best Available Control Technology during simple cycle operation. The Department establishes the following draft BACT standards.

a. Oil Firing: 42 ppmvd @ 15% O_2, 3-hour average
b. Gas Firing: 9.0 ppmvd @ 15% O_2, 24-hour average
c. Gas Firing w/Power Augmentation: 12.0 ppmvd @ 15% O_2, 1-hour average
d. Gas Firing w/Peaking: 15.0 ppmvd @ 15% O_2, 1-hour average

This determination is consistent with recent determinations for simple cycle gas turbine projects in attainment areas. Power augmentation and peaking were separated because of different NOx emissions levels. 1-hour standards were defined because these modes of operation are typically short and no add-on controls are in place. Compliance with the standards will be demonstrated by continuous emissions monitoring system (CEMS). The above limit is much more stringent than the NSPS Subpart GG standard for gas turbines.

6. DRAFT BACT STANDARDS – CARBON MONOXIDE

Discussion of CO Emissions

Gas turbines emit carbon monoxide (CO) due to incomplete combustion of the fuels. For many combustion processes, CO emissions are inversely proportional to NOx emissions. However, the dry low-NOx combustor design for General Electric's Frame 7FA gas turbine has also successfully reduced CO emissions concurrently with NOx emissions.

Applicant's CO BACT Proposal

The applicant identified two control options that are technically feasible and commercially available for gas turbines: an efficient combustion design with good operating practices and a catalytic oxidation system. After attaining lean premix steady-state operation, the dry low-NOx combustion design of the General Electric Model PG7241(FA) gas turbine results in low emissions of CO while also maintaining low NOx emissions. The Speedtronic™ automated gas turbine control system monitors and controls the gas turbine combustion process and operating parameters including, but not limited to, air/fuel distribution and staging, turbine speed, load conditions, temperatures, heat input, and fully automated startup/shutdown. The dry low-NOx combustion design and Speedtronic™ control system are integral to the Model PG7241(FA) gas turbine. "Good operating practices" means operating the unit in accordance with the manufacture's recommendations for efficient combustion, properly maintaining the gas turbine, and appropriate tuning of the combustor and control system. No adverse energy, environmental, or economic impacts were identified with the use of an efficient combustion design and good operating practices.

A catalytic oxidation system consists of a noble metal catalyst section incorporated into the gas turbine exhaust. The catalyst promotes greater oxidation of CO (to carbon dioxide) at much lower temperatures (650°F to 1150°F) than would occur without a catalyst. Control efficiencies are primarily a function of the gas residence time, catalyst activity, and uncontrolled emission levels. Control efficiencies can approach more than 90% given a sufficient inlet concentration. A catalytic oxidation system could be installed either before the HRSG or within the HRSG. Installation within the HRSG would also reduce CO emissions from the duct burner. Capital costs and technical feasibility are not affected by placement of the HRSG.

The applicant recognized a catalytic oxidation system as the top control for CO emissions, but identified the following additional adverse impacts.

Energy Impacts: Installation of a catalytic oxidation system results in a pressure drop across the catalyst bed of approximately 1.5 to 2 inches of water column. This pressure drop causes backpressure on the gas turbine and reduces the power output from the unit resulting in an estimated energy penalty of approximately 3 million kWh/year. The applicant estimates the lost power generation to be approximately equivalent 31 million SCF of natural gas per year to replace the lost energy.

Environmental Impacts: The applicant contends that the maximum CO impacts are less than 0.1% of the applicable ambient air quality standard and no significant environmental benefit is realized by the installation of a catalytic oxidation system. The applicant states that the requirement of an oxidation catalyst would result 1970 tons per year more of carbon dioxide.

Economic Impacts: The applicant estimates that the installation of a catalytic oxidation system would result in total capital investment of approximately $1,644,300 for one gas turbine with a total annualized cost of approximately $691,000 per year per gas turbine. Assuming 85% control efficiency, the catalytic oxidation system would remove in an additional 165 tons of CO per year per gas turbine resulting in a cost effectiveness of approximately $4190 per ton of CO removed.

The applicant rejected the catalytic oxidation system as not cost effective for the project. In addition, the applicant did not believe the additional controls would provide any measurable reductions in air quality impacts. The applicant proposed the following CO emissions standards for project based on the efficient combustion, the firing of natural gas as the primary fuel, and good operating practices.

a. Oil Firing: 20.0 ppmvd (14.1 ppmvd @ 15% O_2)
b. Gas Firing: 9.0 ppmvd (7.4 ppmvd @ 15% O_2)
c. Gas Firing w/Power Augmentation: 15.0 ppmvd (12.0 ppmvd @ 15% O_2)
d. Gas Firing w/Duct Burning: 22.9 ppmvd (14.1 ppmvd @ 15% O_2)
e. Gas Firing w/Power Augmentation and Duct Burning: 29.5 ppmvd (19.2 ppmvd @ 15% O_2)

The applicant requests that compliance with the proposed standards should be based on the average of three test runs conducted in accordance with EPA Method 10.

Department's Draft CO BACT Determinations

The Department also recognizes the catalytic oxidation system as the top control alternative for CO emissions. The Department offers the following comments regarding the applicant's discussion of the additional adverse impacts.

- The Department agrees that installation of a catalytic oxidation system would result in a small energy penalty due to the pressure drop across the catalyst.

- The Department rejects the applicant's argument that the further reduction of CO emissions would have negligible ambient impacts. The PSD preconstruction review process is specifically established for areas that are meeting the ambient air quality standards in order to prevent the deterioration of the current air quality. Actual ambient impacts from the project are evaluated in the modeling analysis and are not considered in making a determination of the Best Available Control Technology. A catalytic oxidation system would also reduce emissions of volatile organic compounds.
- The Department does not endorse the applicant's estimate of the cost effectiveness of $4165/ton of CO removed for a catalytic oxidation system. Recent similar projects (for example, CPV Gulfcoast) have obtained vendor equipment cost quotes that are approximately 25% less. However, the estimate appears to be within the high end of the range of such estimates for other similar projects ($1500 to 4500 per ton).

Recent performance tests for the same model gas turbine indicate actual CO emission levels of less than 1 ppmvd @ 15% O_2 when firing natural gas and less than 2 ppmvd @ 15% O_2 when firing distillate oil (for example, City of Tallahassee's Purdom Generating Station, TECO's Polk Power Station and FPL's Martin Plant). As shown below, recent performance tests for the same model gas turbine at the Gulf Power's Lansing Smith Plant indicate very low CO emissions when injecting steam for power augmentation and duct burning.

Table 6-1. GE Frame 7FA Gas Turbine w/275 MMBtu/hour of Duct Burning

Gulf Power - Lansing Smith Combined Cycle Gas Turbines w/Duct Burning							
		Unit 4 (3/21/2002)			Unit 5 (3/27/2002)		
Parameter	Units	1	2	3	1	2	3
H.I.	MMBtu/hr	2057	2080	2083	2049	2081	2095
CO	ppmvd @ 15% O2	0.98	1.31	1.34	1.30	1.25	1.21
VOC	ppmvd @ 15% O2	0.16	0.15	0.15	0.54	0.23	0.15

Table 6-2. GE Frame 7FA Gas Turbine w/Power Augmentation (Steam Injection)

Gulf Power's Lansing Smith Combined Cycle Gas Turbines w/Power Augmentation							
		Unit 4 (4/5/2002)			Unit 5 (4/12/2002)		
Parameter	Units	1	2	3	1	2	3
H.I.	MMBtu/hr	2106	1982	2004	1950	1949	1953
CO	ppmvd @ 15% O2	4.62	4.67	6.26	8.97	8.12	8.76
VOC	ppmvd @ 15% O2	1.11	0.22	0.50	0.34	0.38	0.42

The CO limits for Units 4 and 5 are 16/23 ppmvd @ 15% O_2 for duct burning/power augmentation. The VOC limits for Units 4 and 5 are 4/6 ppmvd @ 15% O_2 for duct burning/power augmentation. The Department notes little difference in CO and VOC emissions between normal operation and duct burning. The already high combustion temperatures and available oxygen content of the gas turbine exhaust gas (11% to 14%) provide the efficient combustion characteristics necessary to maintain low CO emission levels. However, it is noted that steam injection for power augmentation is shown to have a measurable affect on CO emissions.

As shown by specific test data, CO emissions are much lower than recent permit limits and manufacturer's guarantees. Such low actual CO emissions would tend to drive the cost effectiveness of a catalytic oxidation system even higher. The Department determines that add-on controls to further reduce CO emissions are unwarranted given the low emissions characteristics of this particular gas turbine and the firing of natural gas as the primary fuel. Therefore, a catalytic oxidation system is rejected as not cost effective for this specific project.

Based on the available information regarding duct burning, no separate standard will be established. A slightly higher CO standard will be specified for power augmentation, which is limited to no more than 400 hours per year for each gas turbine. The Department establishes the following draft BACT standards.

a. Oil Firing: 15.0 ppmvd @ 15% O_2, 24-hour block average

b. Gas Firing (with or without duct burning): 8.0 ppmvd @ 15% O_2, 24-hour block average

c. Gas Firing With Power Augmentation: 12 ppmvd @ 15% O_2, 24-hour block average

The "24-hour block average" is defined as the daily average for the actual hours operated in that mode. For example, assume the unit operates 20 hours of normal operation and 4 hours with power augmentation. Then, two separate compliance determinations would be made for the day: one for normal gas firing based on an average of 20 hourly values and one for power augmentation based on an average of 4 hourly values. This determination is consistent with recent determinations for combined cycle gas turbine projects in attainment areas. See Attachment A. Compliance with the CO standard will be demonstrated by continuous emissions monitoring system (CEMS). Continuous monitoring has been standard practice for recent Department determinations for combined cycle gas turbine projects.

7. DRAFT BACT STANDARDS – VOLATILE ORGANIC COMPOUNDS

Discussion

VOC emissions result from incomplete combustion when firing natural gas and distillate oil. Large combustion turbines offer high temperatures with efficient combustion resulting in relatively low levels of volatile organic compounds. For this project, VOC emissions from one gas turbine are expected to be less than 25 tons per year. Similar to the control of carbon monoxide, catalytic oxidation systems are available for reducing VOC emissions from gas turbines. Catalytic oxidation systems can achieve emissions reductions approaching 90% depending on the uncontrolled inlet VOC emission rate. However, such a system was determined to be not cost effective for the control of CO emissions.

Applicant's Proposal

The applicant proposes the following emissions standards based on efficient combustion of natural gas and distillate oil and good operating practices for the gas turbines.

- Oil Firing: 3.5 ppmvw (2.5 ppmvd @ 15% O_2)
- Gas Firing: 1.5 ppmvw (1.3 ppmvd @ 15% O_2)
- Gas Firing with Duct Firing: 7 ppmvw (4.9 ppmvd @ 15% O_2)

The applicant proposes to demonstrate compliance with the standards by conducting performance tests in accordance with EPA Methods 18, 25, and 25A.

Department's Draft VOC BACT Determinations

As discussed previously, the Department agrees that a catalytic oxidation system is not cost effective for this project. Therefore, the efficient combustion design and good operating practices are determined to represent the Best Available Control Technology. Based on the test data previously presented, the Department believes VOC emissions will be much lower than estimated by the applicant. The following are established as the draft BACT standards.

- Oil Firing: 2.5 ppmvd @ 15% O_2
- Gas Firing: 1.3 ppmvd @ 15% O_2
- Gas Firing with Duct Burning: 4.0 ppmvd @ 15% O_2

This determination is consistent with recent determinations for combined cycle gas turbine projects in attainment areas. See Attachment A. Compliance shall be demonstrated by conducting performance tests in accordance with EPA Method 25A. EPA Method 18 may also be performed to deduct emissions of methane and ethane that are excluded from the definition of "VOC".

8. DRAFT BACT STANDARDS - PARTICULATE MATTER

Discussion – Gas Turbines

Emissions of particulate matter will result from incomplete combustion of natural gas and distillate oil as well as contaminants in these fuels. Particulate matter emissions increase with incomplete fuel combustion as well as with higher concentrations of ash, sulfur, and trace elements in a given fuel. However, natural gas is a clean fuel containing little ash, sulfur, or other contaminants. Similarly, distillate oil contains little of these contaminants and is restricted to only 500 hours per year per gas turbine for this project. Attachment A shows typical BACT determinations for particulate matter from large gas turbine projects. Some of the projects include front and back half catch for PM limits; therefore, comparison is not simple. Emissions of particulate matter when injecting ammonia for NOx control may be higher due to the formation of fine particulates such as ammonia sulfates and bisulfates.

Applicant's Proposal – Gas Turbines

At the estimated uncontrolled emission rates when firing natural gas, the applicant states that installation of add-on controls such as baghouses or electrostatic precipitators would be cost prohibitive. In addition to firing natural gas and very low sulfur distillate oil, the applicant proposes the following visible emissions limit as a work practice standard in lieu of a particulate matter emissions standard.

- Visible emissions shall not exceed 10% opacity based on a 6-minute average.

Department's Draft PM BACT Determinations – Gas Turbines

The total potential emissions from a single gas turbine are estimated to be about 60 tons per year. Actual test data indicates that particulate matter emissions may actually be one-tenth of this level. The Department agrees that further control of particulate matter emissions with add-on controls would be cost prohibitive for large gas turbines firing primarily natural gas with restricted amounts of very low sulfur distillate oil. The specification of clean fuels is a pollution prevention technique and is given favorable consideration for this project. Therefore, the following conditions are established as the draft BACT standards.

- The gas turbines shall fire natural gas as the primary fuel, which shall contain no more than 2.0 grains of sulfur per 100 SCF of natural gas. The duct burners are limited to firing only natural gas meeting this specification. The gas turbines may fire distillate oil as a restricted alternate fuel (≤ 500 hours per year), which shall contain no more than 0.05% sulfur by weight.
- Visible emissions shall not exceed 10% opacity based on a 6-minute average.

This determination is consistent with recent determinations for combined cycle gas turbine projects in attainment areas. See Attachment A. Compliance with the fuel specifications shall be determined by records of the fuel analyses. Compliance with the visible emissions standard will be demonstrated by conducting at least annual opacity observations in accordance with EPA Method 9. In addition, the CO CEMS standard will serve a continuous indication of efficient combustion practices to minimize emissions of particulate matter.

Cooling Tower PM Emissions: The applicant's preliminary design includes an 18-cell mechanical draft cooling tower with the following specifications: a circulating water flow rate of 310,000 gpm; design hot/cold water temperatures of 104° F/90° F; a design air flow rate of 1,386,055 per cell; a liquid-to-gas air flow ratio of 1.4; and drift eliminators with a drift rate of no more than 0.001 percent. Cooling towers may emit particulate matter based on the loading in the recirculating water. The Department determines the draft BACT to be a design drift rate of no more than 0.001% of the circulating water flow rate. At this level, maximum potential particulate matter emissions are expected to be 34 tons per year or about 10% of the maximum potential particulate matter emissions from the project. Actual particulate matter emissions are expected to be 34 tons per year.

9. DRAFT BACT STANDARDS – SULFURIC ACID MIST AND SULFUR DIOXIDE

Discussion

Emissions of sulfur dioxide (SO_2) are generated from fuel sulfur with small amounts of SO_2 being converted to sulfuric acid mist (SAM). Natural gas is a clean fuel containing little ash, sulfur, or other contaminants. The distillate oil specified for this project also contains very low sulfur levels.

Applicant's Proposal

The applicant states that flue gas desulfurization systems are not available, technically feasible, demonstrated nor cost effective for gas turbines. The applicant proposes the use of clean fuels as previously specified to limit emissions of SAM and SO_2 from the project.

Department's Draft SAM/SO_2 BACT Determinations

The potential emissions from a single gas turbine are estimated to be 70 tons of SO_2 per year and 7.5 tons of SAM per year. Given the high flow rates and estimated low emission levels, the Department agrees that installation of add-on flue gas desulfurization equipment is not reasonable. All of the recent gas turbine projects (Attachment A) control SO_2 and sulfuric acid mist by limiting the sulfur content of the fuel. The projects ultimately rely on a fairly uniform gas distribution network, which typically provides natural gas with a fuel sulfur content of less than 1 grain per 100 SCF of gas. Distillate oil will be brought to the plant by truck and the vendor must meet contractual specifications regarding the fuel sulfur content. The Department determines that the following fuel specifications represent the Best Available Control Technology for limiting emissions of SAM and SO_2 from the project.

- The gas turbines shall fire natural gas as the primary fuel, which shall contain no more than 2.0 grains of sulfur per 100 SCF. The duct burners are limited to firing only natural gas meeting this specification.
- The gas turbines may fire distillate oil containing no more than 0.05% sulfur by weight as a restricted alternate fuel.

This determination is consistent with recent determinations for combined cycle gas turbine projects in attainment areas. See Attachment A. The above fuel specifications effectively limit potential emissions of SAM and SO_2 emissions, is typically considered BACT for similar gas turbine projects, and is clearly more stringent than the NSPS Subpart GG standard of 0.8% sulfur by weight for gas turbines. Compliance with the fuel specifications shall be determined by records of the fuel analyses.

10. DRAFT STANDARDS FOR AMMONIA SLIP EMISSIONS

Ammonia is injected into the exhaust gas stream as part of the selective catalytic reduction (SCR) system that is used to control NOx emissions. Some of the ammonia will escape past the catalyst without reaction as "ammonia slip" or combine with sulfur to form fine particulate matter such as ammonium sulfates and bisulfates. Elevated levels of ammonia slip may indicate a degrading catalyst. Limiting ammonia slip will also minimize the formation of fine particulate matter formation previously mentioned. Therefore, the following draft ammonia slip standard is specified.

- The SCR system shall be designed and operated for a maximum ammonia slip level of 5 ppmvd @ 15% O_2.

This determination is consistent with recent Department determinations for combined cycle gas turbine projects in Florida. Compliance with the ammonia slip level shall be demonstrated at least annually in accordance with EPA's Conditional Test Method No. 27. Ammonia has been designated as a hazardous substance under federal SARA Title III regulations and must be carefully managed to prevent accidental spills or nitrogen loading of the waters and soils.

11. NSPS REQUIREMENTS

Gas Turbines

Stationary gas turbines are subject to the federal New Source Performance Standards in Subpart GG of 40 CFR 60. These requirements result in the following standards based on compressor inlet conditions of 59° F and 60% relative humidity:

- NOx (gas) ≤ 110 ppmvd @ 15% O_2 (corrected for heat rate of 9250 Btu/KW-h at peak load) and;
- NOx (oil) ≤ 103 ppmvd @ 15% O_2 (corrected for a heat rate of 9960 Btu/KW-h at peak load and 59° F); and
- SO_2 emissions are limited by the use of a fuel with a sulfur content of no more than 0.8% by weight.

The Department considers the draft BACT standards more stringent than the NSPS standards. However, the NSPS also has other specific requirements for notification, record keeping, performance testing, and monitoring of operations. An Appendix to the permit will summarize applicable federal requirements.

Duct Burners

The heat recovery steam generator has gas-fired duct burners with a maximum heat input rate of 495 MMBtu per hour. This subjects the duct burners to the federal New Source Performance Standards in Subpart Da of 40 CFR 60, which applies to combined cycle units with a heat input rate from fossil fuel of more than 250 MMBtu per hour. The following emissions standards apply:

- NOx ≤ 1.6 lb/MW-hr (gross)
- SO_2 ≤ 0.20 lb/MMBtu
- PM ≤ 0.03 lb/MMBtu

The proposed BACT standards for the combination of gas turbine and duct burner emissions are less than 0.07 lb/MW-hr for NOx, 0.008 lb/MMBtu for PM, and less than 0.02 lb/MMBtu for PM (oil firing with ammonia injection), which readily complies with the NSPS standards. An Appendix to the permit will summarize applicable federal requirements.

Gas-Fired Fuel Heaters

The gas-fired fuel heaters each have a maximum heat input rate of 22 MMBtu per hour. The fuel heaters are subject to the federal New Source Performance Standards in Subpart Dc of 40 CFR 60 based on the definition of "steam generators" in that rule. However, such units firing only natural gas are subject to only notification and record keeping requirements. As work practice standards that represent BACT for all pollutants, the draft permit includes: a fuel specification for natural gas (2 grains per 100 SCF of gas) and an opacity limit (10% opacity except for one 6-minute period per hour during which the opacity shall not exceed 20%.)

12. MACT 112(g) APPLICABILITY

EPA is required to promulgate Maximum Available Control Technology (MACT) standards for hazardous air pollutant (HAP) emissions from gas turbines. Because EPA has not yet proposed these standards, states are required to review new projects for the applicability of 112(g). If emissions are 10 tons per year or more of any single HAP or 25 tons per year or more of all combined HAPs, new projects could be subject a case-by-case MACT determination. The applicant estimated total HAP emissions from the proposed project to be less than 15 tons per year, which would not trigger the 112(g) requirement.

In the memorandum dated August 21, 2001, EPA states that the original HAP emissions information (EPA memorandum dated 12/30/99) was based primarily on existing diffusion flame combustor technology. This technology results in higher emissions of CO, NOx, and HAPs than lean pre-mix combustor designs, such as General Electric's dry low-NOx combustion technology. Based on additional emissions performance testing, EPA states that the average formaldehyde emissions factor is 6.49×10^{-05} lb/MMBtu for large gas turbines (10

MW to 170 MW) utilizing lean premix combustion. Because formaldehyde had the highest emission rate for HAPs, it is reasonable to assume that other HAPs would also be much lower for lean premix combustion.

One theory for the much lower HAP emission levels is that, although the premixing of fuel and air with staged entry limits flame temperature and residence time at peak flame temperatures, it also reduces "cold spots" throughout the combustion zone providing more uniform destruction. EPA also states that, "For purposes of monitoring HAP performance of lean premix combustor turbines, NOx emission levels characteristic of lean premix combustor technology could be used as an indicator of proper lean premix combustor performance, which in turn would assure proper operation and low HAP emissions." The Department believes that the project has potential HAP emissions of less than 10 tons per year for all individual HAPs and less than 25 tons per year for all combined HAPs. Based on all of the available information, a case-by-case 112(g) MACT determination is not required for this project. Each gas turbine will continuously monitor CO and NOx emissions, which will ensure proper lean premix combustor performance and thereby low HAP emissions.

13. PERIODS OF EXCESS EMISSIONS

Excess Emissions Prohibited

In accordance with Rule 62-210.700(4), F.A.C., "Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown, or malfunction shall be prohibited." All such preventable emissions shall be included in the compliance determinations for CO and NOx emissions.

Alternate Standards and Excess Emissions Allowed

In accordance with Rule 62-210.700, F.A.C., "Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration." In addition, the rule states that, "Considering operational variations in types of industrial equipment operations affected by this rule, the Department may adjust maximum and minimum factors to provide reasonable and practical regulatory controls consistent with the public interest." Therefore, the Department has the authority to regulate defined periods of operation that may result in emissions in excess of the proposed BACT standards based on the given characteristics of the specific project.

Operation of the General Electric Frame 7FA gas turbine in lean premix mode is achieved by at least 50% of base load conditions. Recent conversations indicate that full lean premix operation may occur between 40% and 50% of base load, but this has not yet been verified. During a startup to simple cycle mode, the gas turbine will not reach lean premix operation (50% load) until about 15 minutes into the start (perhaps 30 minutes for a hot nozzle combustor design). Therefore, emissions for this 15-minute period will be greater than the permitted emissions standards. Shutdowns offer similar performance. In addition, a startup when the heat recovery steam generator (HRSG) or steam turbine-electrical generator is cold must be performed gradually to prevent thermal damage to the components. The gradual warming of the HRSG and steam turbine components is accomplished by operating the gas turbines for extended periods at reduced loads (<10%), which results in higher emissions. In general, the sequences of startup/shutdown are managed by the automated control system.

Based on information from General Electric regarding startup and shutdown, the Department establishes the following conditions for excess emissions for each gas turbine/HRSG system.

- 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 resulting from startup, shutdown, or documented malfunctions occurrences shall in no case exceed two hours in any 24-hour period except for the following specific cases.
- For warm startup to combined cycle operation, up to three hours of excess emissions are allowed. "Warm

startup" is defined as a startup to combined cycle operation following a shutdown lasting at least 24 hours.

- For cold startup to combined cycle operation, up to four hours of excess emissions are allowed. "Cold startup" is defined as a startup to combined cycle operation following a shutdown lasting at least 48 hours.
- For shutdown from combined cycle operation, up to three hours of excess emissions are allowed.
- For days with simple cycle operation, excess emissions shall not exceed three hours in any 24-hour period due to all combined occurrences of startups, shutdowns, and malfunctions. For days with combined cycle operation, excess emissions shall not exceed four hours in any 24-hour period due to all combined occurrences of startups, shutdowns, and malfunctions.
- For startup to combined cycle operation, ammonia injection shall begin as soon as the system reaches the manufacturer's specifications.
- During startup and shutdown, the opacity of the exhaust gases shall not exceed 10%, except for up to ten 6-minute averaging periods in a calendar day during which the opacity shall not exceed 20%. Data for each 6-minute averaging period shall be exclusive from other 6-minute averaging periods.

While NOx emissions during warm and cold startups are greater than during full load steady-state operation, such startups are infrequent. Also, it is noted that such startups would be preceded by shutdowns of at least 24 or 48 hours. Therefore, the startup emissions would not cause annual emissions greater than the potential emissions under continuous operation. The draft permit will also require the installation of a damper to reduce heat loss during combined cycle shutdowns to minimize the number of combined cycle cold startups.

Initial Steam Blows: Prior to completing the conversion from simple cycle to combined cycle operation, the permittee is authorized to operate each gas turbine at loads below 50% for the purpose of cleaning the HRSG piping system and piping connecting the HRSG to the steam turbine. Prior to conducting any steam blows, the permittee shall submit a proposed schedule. On the first day of conducting steam blows, the permittee shall notify the Compliance Authority that the process has begun. The permittee shall complete this process within 90 days of conducting the initial steam blow. During the steam blows, the following conditions apply:

- The permittee shall take all precautions to minimize the extent and duration of excess emissions.
- Each gas turbine shall fire only natural gas and each CEMS shall be on line and functioning properly.
- CO and NOx emissions may exceed the BACT limits specified in this permit; however, NOx emissions shall not exceed the NSPS Subpart GG limit of 110 ppmvd corrected to 15% oxygen based on a 24-hour block average. If the NSPS standard is exceeded, the permittee shall notify the Compliance Authority within 24-hours of the incident.

Within 30 days of completing the initial steam blows, the permittee shall submit a report to the Bureau of Air Regulation and the Compliance Authority summarizing the daily emissions resulting from each steam blow. {Permitting Note: It is estimated that steam blows will occur intermittently over a 30-day period for each gas turbine/HRSG system followed by a similar 60-day period of intermittent steam blows for the common piping system serving the four interconnected combined cycle units. It is not expected that steam blows would occur every day during these periods.} [Design; Rules 62-212.400(BACT) and 62-210.700(5), F.A.C.]

Combined Cycle Operation With Dump Condenser: If the steam-electrical turbine generator was off line for some reason, it is possible that the gas turbine/HRSG systems would operate without producing any steam generated power. Instead, steam would be delivered to a dump condenser. Although this method of operation is inefficient, it may be preferable due to the time necessary to shutdown, cool, and prepare the units for simple cycle operation. Apparently, a baffle plate must be unbolted, removed and repositioned for simple cycle operation, which takes at least a day. Operation with a dump condenser must still meet the standards established for combined cycle operation with ammonia injection.

14. DEPARTMENT'S ESTIMATED ANNUAL EMISSIONS

The following table shows the estimated annual emissions from the completed combined cycle unit based on the draft permit conditions.

Pollutant	Project Emissions, TPY
CO	589
Pb	0.03
NOx	683
PM	288
SO_2	276
SAM	30
VOC	75

15. AIR QUALITY IMPACT ANALYSIS

Introduction

The proposed project will increase emissions of six pollutants at levels in excess of PSD significant amounts: PM/PM_{10}, CO, NO_X, SO_2, VOC and SAM. PM_{10}, SO_2 and NO_X are criteria pollutants and have national and state ambient air quality standards (AAQS), PSD increments, significant impact levels and de minimis monitoring levels defined for them. CO is a criteria pollutant and has only AAQS, significant impact levels and de minimis monitoring levels defined for it. There are no applicable PSD increments, AAQS, significant impact or de minimis monitoring levels for SAM and VOC. However, VOC is a precursor to a criteria pollutant, ozone; and any net increase of 100 tons per year of VOC requires an ambient impact analysis including the gathering of preconstruction ambient air quality data.

Major Stationary Sources in Martin County

The current largest stationary sources of air pollution in Martin County are listed below:

TABLE 15-1. MAJOR SOURCES OF SO_2 IN MARTIN COUNTY (2000)

Owner/Company	Site Name	Tons per year
Florida Power and Light	Martin Power Plant (Existing boilers)	15,573
Indiantown	Indiantown	1,870
Florida Power and Light	*Martin Power Plant (Proposed turbines)*	*280**

* Potential emissions

TABLE 15-2. MAJOR SOURCES OF NO_X IN MARTIN COUNTY (2000)

Owner/Company	Site Name	Tons per year
Florida Power and Light	Martin Power Plant	6,425
Indiantown	Indiantown	2,136
Florida Power and Light	*Martin Power Plant (Proposed turbines)*	*683**

* Potential emissions

TABLE 15-3. MAJOR SOURCES OF VOC IN MARTIN COUNTY (2000)

Owner/Company	Site Name	Tons per year
Louis Dreyfus	Louis Dreyfus	245
Florida Power and Light	Martin Power Plant (Existing boilers)	170
Florida Power and Light	*Martin Power Plant (Proposed turbines)*	*110*/75*

* Potential emissions based on application. Revised downward based on Department's draft BACT Determination.

TABLE 15-4. MAJOR SOURCES OF PM IN MARTIN COUNTY (2000)

Owner/Company	Site Name	Tons per year
Florida Power and Light	Martin Power Plant (Existing boilers)	1,452
Florida Power and Light	*Martin Power Plant (Proposed turbines)*	*322**
Indiantown	Indiantown	119

* Potential emissions

TABLE 15-5. MAJOR SOURCES OF CO IN MARTIN COUNTY (2000)

Owner/Company	Site Name	Tons per year
Florida Power and Light	Martin Power Plant (Existing boilers)	11,345
Florida Power and Light	*Martin Power Plant (Proposed turbines)*	*826**
Indiantown	Indiantown	130

* Potential emissions

Air Quality and Monitoring in the Martin County

The Martin County Region has five monitors at four sites measuring PM_{10}, ozone, CO, SO_2 and NO_2. The 2001 monitoring network is shown in Figure 15-1 at the right.

Measured ambient air quality is given in Table 15-6 on the following page. The highest measured values are all less than the respective National Ambient Air Quality Standards. The average measurements are all less than the respective standards.

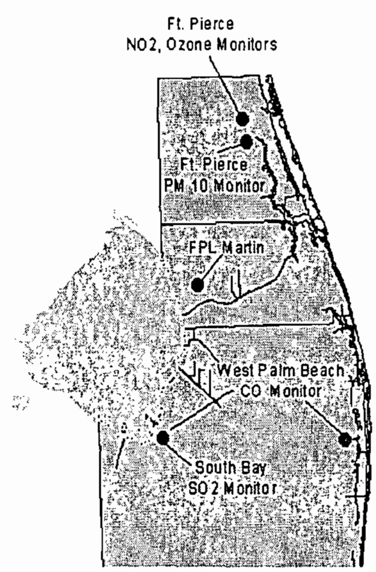


Figure 15-1. Martin County Regional Monitoring Network

TABLE 15-6. 2000 AMBIENT AIR QUALITY NEAR PROJECT SITE

Pollutant	Site Location			Averaging	Ambient Concentration				
	City	Site no.	UTM	Period	1st High	2nd High	Mean	Standard	Units
PM_{10}	Ft. Pierce	111-0012	17-3029.7N-559.4E	24-hour	37	35		150[a]	ug/m^3
				Annual			18	50[b]	ug/m^3
SO_2	South Bay	099-2101	17-2949.5N-528.5E	3-hour	15	9		500[a]	ppb
				24-hour	4	3		100[a]	ppb
				Annual			2	20[b]	ppb
NO_2	Ft. Pierce	111-1002	17-3036.2N-558.5E	Annual			10	53[b]	ppb
CO	West Palm Bch	099-1006	17-2952.4N-589.5E	1-hour	4	4		35[a]	ppm
				8-hour	3	3		9[a]	ppm
Ozone	Fort Pierce	111-1002	17-3036.2-558.5E	1-hour	0.082	0.079		0.12[c]	ppm

a - Not to be exceeded more than once per year.
b - Arithmetic mean.
c - Not to be exceeded on more than an average of one day per year over a three-year period.

Air Quality Impact Analysis

Significant Impact Analysis: For PM/PM_{10}, CO, NO_X and SO_2, which have significant impact levels defined for them, a significant impact analysis is performed. In order to conduct a significant impact analysis, the applicant uses the proposed project's emissions at worst load conditions as inputs to the models. The models used in this analysis and any required subsequent modeling analyses are described in 6.5.4. The highest predicted short-term concentrations and highest predicted annual averages predicted by this modeling are compared to the appropriate significant impact levels for the Class I and II Areas.

If this modeling at worst-load conditions shows significant impacts, additional modeling, which includes the emissions from surrounding facilities, or multi-source modeling is required to determine the project's impacts on any applicable AAQS or PSD increments. If no significant impacts are shown, the applicant is exempted from doing any further modeling.

The applicant's initial PM/PM_{10}, CO, NO_X, and SO_2 air quality impact analyses for this project indicated that maximum predicted impacts from all pollutants (except for 24-hour SO_2) are less than the applicable "significant impact levels." These values are tabulated in the table on the following page and compared with existing ambient air quality measurements from the local ambient monitoring network.

It is obvious that maximum predicted impacts from the project are much less than the respective AAQS and the baseline concentrations in the area (except for 24-hour SO_2). They are also less than the respective significant impact levels (except for 24-hour SO_2) that would otherwise require more detailed modeling efforts. The maximum predicted 24-hour SO_2 impacts are approximately equal to the baseline concentrations collected at the SO_2 monitor, which is located in a rural area. However, these predicted concentrations are much less than the AAQS. In the case of 24-hour SO_2, additional modeling was required, which showed maximum impacts from all sources in the area were much lower than the AAQS. The results of this modeling are given in Table 15-7.

TABLE 15-7. MAXIMUM PROJECT AIR QUALITY IMPACTS FROM THE FPL PROJECT FOR COMPARISON TO THE PSD CLASS II SIGNIFICANT IMPACT LEVELS

Pollutant	Averaging Time	Max Predicted Impact (ug/m^3)	Significant Impact Level (ug/m^3)	Baseline Concentrations (ug/m^3)	Ambient Air Standards (ug/m^3)	Significant Impact?
SO_2	Annual	0.6	1	~5	60	NO
	24-Hour	9	5	~10	260	YES
	3-Hour	18	25	~40	1300	NO
PM_{10}	Annual	0.3	1	~20	50	NO
	24-Hour	4.4	5	~40	150	NO
CO	8-Hour	8	500	~3300	10,000	NO
	1-Hour	20	2000	~4500	40,000	NO
NO_2	Annual	0.6	1	~10	100	NO

The nearest PSD Class I area is the Everglades National Park (ENP) located about 145 km to the south. The applicant's initial PM/PM_{10}, NO_X and SO_2 air quality impact analyses for this project indicated that maximum predicted impacts from all pollutants are less than the applicable significant impact levels (except for 24-hour SO_2) for the Class I area. These values are tabulated below. Note that the values are miniscule if compared with the ambient air quality standards given in the previous table. Since these impacts are less than the respective significant impact levels, no further detailed modeling efforts are required in this Class I area (except for 24-hour SO_2). In the case of 24-hour SO_2, additional modeling was required, which showed impacts from all sources in the area were lower than the PSD Class I increment, which in turn, is much lower than the AAQS. The results of the 24-hour SO_2 multi-source PSD Class I increment are presented in Table 15-8.

TABLE 15-8. MAXIMUM PROJECT AIR QUALITY IMPACTS FROM THE FPL PROJECT COMPARED WITH PSD CLASS I SIGNIFICANT IMPACT LEVELS (EVERGLADES)

Pollutant	Averaging Time	Max. Predicted Impact at Class I Area (ug/m^3)	Class I Significant Impact Level (ug/m^3)	Significant Impact?
PM_{10}	Annual	0.002	0.2	NO
	24-hour	0.07	0.3	NO
NO_2	Annual	0.002	0.1	NO
SO_2	Annual	0.001	0.1	NO
	24-hour	0.4	0.2	YES
	3-hour	0.7	1	NO

Preconstruction Ambient Monitoring Requirements

A preconstruction monitoring analysis is done for those pollutants with listed de minimis impact levels. These are levels, which, if exceeded, would require pre-construction ambient monitoring. For this analysis, as was done for the significant impact analysis, the applicant uses the proposed project's emissions at worst load conditions as inputs to the models. As shown in Table 15-9, the maximum predicted impacts for all pollutants with listed de minimis impact levels were less than these levels. Therefore, no pre-construction monitoring is required for those pollutants.

TABLE 15-9. MAXIMUM PROJECT AIR QUALITY IMPACTS FOR COMPARISON TO THE DE MINIMUS AMBIENT IMPACT LEVELS

Pollutant	Averaging Time	Max Predicted Impact (ug/m^3)	De Minimis Level (ug/m^3)	Baseline Concentrations (ug/m^3)	Impact Greater Than De Minimis?
PM_{10}	24-hour	4	10	~40	NO
NO_2	Annual	1	14	~10	NO
SO_2	24-hour	9	13	~10	NO
CO	8-hour	16	575	~3300	NO

There are no ambient standards or *de minimus* air quality levels associated with VOC, which is a precursor for the pollutant ozone. The impacts of VOC emissions on ozone levels are not usually seen locally, but contribute to regional formation of ozone. Projects with VOC emissions greater than 100 tons per year are required to perform an ambient impact analysis for ozone including the gathering of preconstruction ambient air quality data. Although the applicant estimated annual potential VOC emissions from the project to be greater than 100 tons per year, the draft permit limits VOC emissions below 100 tons per year. Therefore, preconstruction monitoring for ozone is not required. The three regional ozone monitors in the area (West Palm Beach and Ft. Pierce) suffice for any background ozone pre-construction monitoring requirements.

Based on the preceding discussions, the only additional detailed air quality analyses (inclusive of all sources in the area) required by the PSD regulations for this project are the following:

- A multi-source AAQS and PSD increment analysis for 24-hour SO_2 in the Class II area in the vicinity of the project and the ENP Class I area;
- An analysis of impacts on ground level ozone; and
- An analysis of impacts on soils, vegetation, visibility, and of growth-related air quality modeling impacts.

Models and Meteorological Data Used in the Air Quality Analysis

PSD Class II Area: The EPA-approved Industrial Source Complex Short-Term (ISCST3) dispersion model was used to evaluate the pollutant emissions from the proposed project in the surrounding Class II Area. This model determines ground-level concentrations of inert gases or small particles emitted into the atmosphere by point, area, and volume sources. It incorporates elements for plume rise, transport by the mean wind, Gaussian dispersion, and pollutant removal mechanisms such as deposition. The ISCST3 model allows for the separation of sources, building wake downwash, and various other input/output parameters. A series of specific model features, recommended by the EPA, are referred to as the regulatory options. The applicant used the EPA recommended regulatory options. Direction-specific downwash parameters were used for all sources for which downwash was considered. The stacks associated with this project all satisfied the good engineering practice (GEP) stack height criteria.

Meteorological data used in the ISCST3 model consisted of a concurrent 5-year period of hourly surface weather observations and twice-daily upper air soundings from Palm Beach International Airport. The 5-year period of meteorological data was from 1987 through 1991. This airport station was selected for use in the study because it is the closest primary weather station to the study area and is most representative of the project site. The surface observations included wind direction, wind speed, temperature, cloud cover, and cloud ceiling.

In reviewing this permit application, the Department has determined that the application complies with the applicable provisions of the stack height regulations as revised by EPA on July 8, 1985 (50 FR 27892). Portions of the regulations have been remanded by a panel of the U.S. Court of Appeals for the D.C. Circuit in NRDC v. Thomas, 838 F. 2d 1224 (D.C. Cir. 1988). Consequently, this permit may be subject to modification should

EPA revise the regulation in response to the court decision. This may result in revised emission limitations or may affect other actions taken by the source owners or operators. A more detailed discussion of the required analyses follows.

PSD Class I Area: The California Puff (CALPUFF) dispersion model was used to evaluate the pollutant emissions from the proposed project in the Class I CNWA. Meteorological data used in this model was from 1990. Meteorological surface data used were from Gainesville, Tampa, Daytona Beach, Vero Beach, Fort Myers, Key West, Miami and Orlando. Meteorological upper air data used were from Ruskin, Key West and West Palm Beach. Hourly precipitation data were obtained from 23 stations around the central and southern part of the state.

CALPUFF is a non-steady state, Lagrangian, long-range transport model that incorporates Gaussian puff dispersion algorithms. This model determines ground-level concentrations of inert gases or small particles emitted into the atmosphere by point, line, area, and volume sources. The CALPUFF model has the capability to treat time-varying sources, is suitable for modeling domains from tens of meters to hundreds of kilometers, and has mechanisms to handle rough or complex terrain situations. Finally, the CALPUFF model is applicable for inert pollutants as well as pollutants that are subject to linear removal and chemical conversion mechanism.

Multi-source AAQS SO_2 Analysis

For pollutants subject to a multi-source AAQS review, the total impact on ambient air quality is obtained by adding a "background" concentration to the maximum modeled concentration. This background concentration takes into account all sources of a particular pollutant that are not explicitly modeled. The results of the AAQS analysis are summarized in the table below. As shown, emissions from the proposed facility are not expected to cause or contribute to a violation of an AAQS.

TABLE 15-10. AMBIENT AIR QUALITY IMPACTS

Pollutant	Averaging Time	Major Source Impact (ug/m^3)	Background Concentration (ug/m^3)	Total Impact (ug/m^3)	Total Impact Greater Than AAQS?	Florida AAQS (ug/m^3)
SO_2	24-hour	75	10	85	NO	260

Multi-source PSD Class II Increment Analysis for SO_2

The multi-source PSD increment represents the amount that all new sources in an area may increase ambient ground level concentrations of a pollutant from a baseline concentration, which was established in 1977 for SO_2 (the baseline year was 1975 for existing major sources of SO_2). The maximum predicted 24-hour SO_2 PSD Class II area impacts from this project and all other increment-consuming sources in the vicinity of FPL Martin are shown in the following table. As shown, the maximum predicted impacts are much less than the allowable Class II SO_2 increments.

TABLE 15-11. PSD CLASS II INCREMENT ANALYSIS

Pollutant	Averaging Time	Maximum Predicted Impact (μg/m^3)	Impact Greater Than Allowable Increment?	Allowable Increment (μg/m^3)
SO_2	24-hour	41	NO	91

Multi-source PSD Class Increment Analysis for SO_2

The maximum predicted 24-hour SO_2 PSD Class I area impacts from this project and all other increment-consuming sources in the vicinity of the ENP are shown in the following table. As shown, the maximum predicted impacts are less than the allowable Class I 24-hour SO_2 increment in the ENP.

TABLE 15-12. PSD CLASS I INCREMENT ANALYSIS – ENP

Pollutant	Averaging Time	Maximum Predicted Impact ($\mu g/m^3$)	Impact Greater Than Allowable Increment?	Allowable Increment ($\mu g/m^3$)
SO_2	24-hr	3.5	NO	5

Ozone Impact Assessment

The Department's draft BACT will limit the VOC emissions increase to 75 tons per year. These emissions will be less than the 100 tons per year significant impact level, which would require an ambient air quality analysis. Therefore modeling of impacts on ozone due to VOC emissions is not required.

Additional Impacts Analysis

Impact on Soils, Vegetation, And Wildlife: Very low emissions are expected from the natural gas and distillate oil fired gas turbines in comparison with conventional power plants generating equal power. Emissions of acid rain and ozone precursors will be very low. The maximum ground-level concentrations predicted to occur for PM_{10}, CO, NO_X, and SO_2 as a result of the proposed project, including background concentrations and all other nearby sources, will be considerably less than the respective AAQS. In addition, the project impacts for PM_{10}, CO and NO_X are less than the significant impact levels, which, in turn, are less than the applicable allowable increments for each pollutant. The AAQS are designed to protect both the public health and welfare. Since the project impacts are either less than significant or considerably less than the AAQS, it is reasonable to assume the impacts on soils, vegetation, or wildlife will be minimal or insignificant.

Impact On Visibility and Regional Haze: Natural gas and low sulfur distillate fuel oil are clean fuels that contain little ash or other contaminants. The low NO_X and SO_2 emissions will also minimize plume opacity. The contribution to smog in the area will be minimal. The applicant submitted a regional haze analysis for the ENP. Based on NPS criteria, no adverse impacts are predicted.

Growth-Related Air Quality Impacts: There will be short-term increases in the labor force to construct the project. These temporary increases will not result in significant commercial and residential growth near the project. Operation of the additional units will require few new permanent employees, which will cause no significant impact on the local area.

16. PRELIMINARY DETERMINATION

The Department makes a preliminary determination that the proposed project will comply with all applicable state and federal air pollution regulations as conditioned by the Draft Permit. This determination is based on a technical review of the complete PSD application, reasonable assurances provided by the applicant, the draft determinations of Best Available Control Technology (BACT), review of the air quality impact analysis, and the conditions specified in the draft permit. Cleve Holladay is the project meteorologist responsible for reviewing and validating the air quality impact analysis. Jeff Koerner is the project engineer responsible for reviewing the application, recommending the BACT determinations, and drafting the permit. Additional details of this analysis may be obtained by contacting the project engineer at 850/488-0114 or the Department's Bureau of Air Regulation at Mail Station #5505, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400.

Table A-1. Recent NOx Standards Proposed for "F-Class" Simple Cycle Gas Turbine Projects in the Southeast

Project Location	Capacity (MW)	NOx Limit ppmvd @ 15% O2	Technology	Comments
El Paso Manatee, FL	350	9 NG	DLN	2x175 MW GE 7FA CTs (Gas only
El Paso Deerfield, FL	525	9 - NG	DLN	3x175 MW GE 7FA CTs Draft 8/2001. Gas Only
Enron Deerfield, FL	510	9 - NG 36 - No. 2 FO	DLN WI	3x170 MW GE 7FA CTs Draft 06/01. 500 hrs on oil
Enron Pompano, FL	510	9 - NG 36 - No. 2 FO	DLN WI	3x170 MW GE 7FA CTs Revised Draft 06/01. 500 hrs on oil
Midway St. Lucie, FL	510	9 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE 7FA CTs Issued 2/01. 1000 hrs on oil
DeSoto County, FL	510	9 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE 7FA CTs Issued 7/00. 1000 hrs on oil
Shady Hills Pasco, FL	510	9 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE 7FA CTs Issued 1/00. 1000 hrs on oil
Vandolah Hardee, FL	680	9 - NG 42 - No. 2 FO	DLN WI	4x170 MW GE 7FA CTs Issued 11/99. 1000 hrs on oil
Oleander Brevard, FL	850	9 - NG 42 - No. 2 FO	DLN WI	5x170 MW GE 7FA CTs Issued 11/99. 1000 hrs on oil
JEA Baldwin, FL	510	10.5 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE 7FA CTs Issued 10/99. 750 hrs on oil
TEC Polk Power, FL	330	10.5 – NG 42 – No. 2 F.O.	DLN WI	2x165 MW GE 7FA CTs Issued 10/99. 750 hrs on oil
Dynegy, FL	510	15 – NG	DLN	3x170 MW WH 501F CTs Issued. Gas only
Dynegy Heard, GA	510	15 – NG	DLN	3x170 MW WH 501F CTs Issued. Gas only
Thomaston, GA	680	15 - NG 42 - No. 2 FO	DLN WI	4x170 MW GE 7FA CTs Issued. 1687 hrs on oil
Dynegy Reidsville, NC	900	15 – NG (by 2002) 42 – No. 2 FO	DLN WI	5x180 MW WH 501F CTs Initially 25 ppm NO_X limit on gas Issued. 1000 hrs on oil.
Southern Energy, WI	525	15/12 – NG 42 - No. 2 FO	DLN WI	3x175 MW GE 7FA CTs 15/12 ppm are on 1/24 hr basis Issued 1/99. 800 hrs on oil
Lakeland, FL	250 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.

Notes:

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

Table A-2. Recent CO, PM, and VOC Standards for "F-Class" Simple Cycle Gas Turbine Projects in the Southeast

Project Location	CO - ppm (or as indicated)	VOC - ppm (or as indicated)	PM - lb/hr (or as indicated)	Technology and Comments
El Paso Manatee, FL	8 (7.4@15% O_2) - N	1.4 (1.3@15% O_2)	18 lb/hr (Front & Back	Clean Fuels Good Combustion
El Paso Deerfield, FL	8 (7.4@15% O_2) - NG	1.4 (1.3@15% O2)	18 lb/hr (Front & Back)	Clean Fuels Good Combustion
Enron Deerfield, FL	9 - NG 30 - FO	1.4 – NG 1.4– FO	18 lb/hr - NG 34 lb/hr - FO	Clean Fuels Good Combustion
Pompano Beach, FL	9 - NG 30 - FO	1.4 – NG 1.4– FO	10 lb/hr - NG 17 lb/hr - FO	Clean Fuels Good Combustion
Midway St. Lucie, FL	9 - NG 30 - FO	1.4 – NG 1.4– FO	10 lb/hr - NG 17 lb/hr - FO	Clean Fuels Good Combustion
DeSoto County, FL	12 - NG 20 - FO	1.4 – NG 7 – FO	10 lb/hr - NG 17 lb/hr - FO	Clean Fuels Good Combustion
Shady Hills Pasco, FL	12 - NG 20 - FO	1.4 – NG 7 – FO	10 lb/hr - NG 17 lb/hr - FO	Clean Fuels Good Combustion
Vandolah Hardee, FL	12 - NG 20 - FO	1.4 – NG 7 – FO	10 lb/hr - NG 17 lb/hr - FO	Clean Fuels Good Combustion
Oleander Brevard, FL	12 - NG 20 - FO	3 – NG 6 – FO	10% Opacity	Clean Fuels Good Combustion
JEA Baldwin, FL	12 - NG 20 - FO	1.4 – NG/FO Not PSD	9/17 lb/hr – NG/FO 10% Opacity	Clean Fuels Good Combustion
TEC Polk Power, FL	15 - NG 33 - FO	7 – NG 7 – FO	10% Opacity	Clean Fuels Good Combustion
Dynegy, FL	25 - NG	? – NG	? - NG	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
Southern Energy, 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
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
Lakeland, FL	25 - NG or 10 by Ox Cat 75 - FO @ 15% O_2	4 – NG 10 – FO	10% Opacity	Clean Fuels Good Combustion

Notes:

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

Table A-3. Recent NOx Standards for "F-Class" Combined Cycle Gas Turbine Projects in the Southeast

Project Location	Capacity MW	NOx Limit ppmvd @ 15% O_2 and Fuel	Technology	Comments
El Paso Manatee, FL	250	2.5 – NG	SCR	175 MW GE 7FA
El Paso Deerfield, FL	250	2.5 – NG	SCR	175 MW GE 7FA Draft 8/2001
CPV Pierce, FL	245	2.5 – NG 10 – FO	SCR	170 MW GE 7FA CT 7/2001
Metcalf Energy, CA	600	2.5 – NG	SCR	2x170 MW WH501F & Duct Burners
Enron/Ft. Pierce, FL	~250	3.5 – NG 10 - FO	SCR	170 MW MHI501F CT Repowering
CPV Atlantic, FL	245	3.5 – NG 10 – FO	SCR	170 MW GE 7FA CT
CPV Gulfcoast, FL	245	3.5 – NG 10 – FO	SCR	170 MW GE 7FA CT
TECO Bayside, FL	1750	3.5 – NG 12 - FO	SCR	7x170 MW GE 7FA CTs, Repowering
FPC Hines II, FL	530	3.5 - NG 12 - FO	SCR	2x170 MW WH501F
Calpine Osprey, FL	527	3.5 – NG	SCR	2x170 MW WH501F Draft 5/00
Calpine Blue Heron, FL	1080	3.5 – NG	SCR	4x170 MW WH501F Draft 2/00
Mobile Energy, AL	~250	~3.5 - NG ~11 – FO	SCR	178 MW GE 7FA CT 1/99
Alabama Power Barry	800	3.5 - NG	SCR	3x170 MW GE 7FA CTs 11/98
Alabama Power Theo	210	3.5 – NG	SCR	4x170 MW GE 7FA CTs 11/98
KUA Cane Island 3, FL	250	3.5 – NG 15 - FO	SCR	170 MW GE 7FA. 11/99
Lake Worth LLC, FL	250	9 or 3.5 – NG 9.4 or 3.5 – NG (CT&DB) 42 or 16.4 - FO	DLN or SCR DLN or SCR WI or SCR	170 MW GE 7FA. 11/99 Increase allowed for DB under DLN.
Miss Power Daniel	1000	3.5 – NG	SCR	4x170 MW GE 7FA CTs 11/98

Notes:

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

Table A-4. Recent CO, PM, and VOC Standards for "F-Class" Combined Cycle Gas Turbine Projects in the Southeast

Project Location	CO - ppmvd (or lb/MMBtu)	VOC - ppmv (or lb/MMBtu)	PM - lb/MMBtu (or gr/dscf or lb/hr)	Technology and Comments
El Paso Manatee, FL	9 (7.4 @15% O_2) 15 (12 @15% O_2) (PA)	1.4 - NG	20 lb/hr – (Front & Back) 5 ppmvd Ammonia Slip	Clean Fuels Good Combustion
El Paso Deerfield, FL	9 (7.4 @15% O2) 15 (12 @15% O2) (PA)	1.4 - NG	20 lb/hr – (Front & Back) 5 ppmvd Ammonia Slip	Clean Fuels Good Combustion
CPV Pierce, FL	9 - NG (50 - 100% load) 15 - NG (PA) 20 – FO	1.4 – NG 3.5 FO	11 lb/hr – NG (front) 36 lb/hr – FO (front) 5 ppmvd Ammonia Slip	Clean Fuels Good Combustion
Metcalf Energy, CA	6 - NG (100% load)	0.00126 lb/MMBtu	12 lb/hr – NG (w DB) 5 ppmvd Ammonia Slip	Clean Fuels Good Combustion
Enron Ft. Pierce, FL	3.5 - NG 10 - Low Load 8 - FO	2.2 - NG 16 – Low Load 10 - FO	10% Opacity	Oxidation Catalyst Clean Fuels Good Combustion
CPV Atlantic, FL	9 - NG (50 - 100% load) 15 - NG (PA) 20 – FO	1.4 – NG 3.5 FO	11 lb/hr – NG (front) 36 lb/hr – FO (front) 5 ppmvd Ammonia Slip	Clean Fuels Good Combustion
CPV Gulfcoast, FL	9 - NG (50 - 100% load) 15 - NG (PA) 20 – FO	1.4 – NG 3.5 FO	11 lb/hr – NG (front) 36 lb/hr – FO (front) 5 ppmvd Ammonia Slip	Clean Fuels Good Combustion
TECO Bayside, FL	9 – NG (24-hr CEMS) 20 – FO (24-hr CEMS)	1.3 – NG 3 - FO	12 lb/hr – NG 30 lb/hr - FO	Clean Fuels Good Combustion
FPC Hines II, FL	16 - NG (24-hr CEMS) 30 – FO (24-hr CEMS)	2 – NG 10 – FO	10% Opacity – NG 5/9 ammonia – NG/FO	Clean Fuels Good Combustion
Calpine Osprey, FL	10 – NG 17 – NG (DB&PA)	2.3 – NG 4.6 – NG (DB&PA)	24 lb/hr – NG (DB&PA) 10 percent Opacity 9 ppmvd Ammonia Slip	Clean Fuels Good Combustion
Calpine Blue Heron, FL	10 – NG (24-hr CEMS) 17 – NG (DB&PA)	1.2 – NG 6.6 – NG (DB&PA)	31.9 lb/hr – NG (DB&PA) 10 percent Opacity 5 ppmvd Ammonia Slip	Clean Fuels Good Combustion
Mobile Energy, AL	~18 – NG ~26 – FO	~5 – NG ~6 - FO	10% Opacity	Clean Fuels Good Combustion
Alabama Power Barry, AL	~15 – NG(CT) ~25 – NG(DB & CT)	~8 - NG(CT) ~12 – NG(CT & DB)	0.010 lb/MMBtu – (CT) 0.011 lb/MMBtu -(CT/DB) 10% Opacity	Clean Fuels Good Combustion
KUA Cane Island, FL	10 - NG (CT) 20 - NG (CT&DB) 30 - FO	1.4 - NG (CT) 4 - NG (CT&DB) 10 - FO	10% Opacity	Clean Fuels Good Combustion
Lake Worth LLC, FL	9 - NG (CT) 15 – NG (CT & DB) 20 - F.O. (3-hr)	1.4 - NG (CT) 1.8 - NG (CT & DB) 3.5 – F.O.	10% Opacity	Clean Fuels Good Combustion
Miss Power Daniel,	~15 - NG(CT) ~25 – NG(DB & CT	~8 - NG(CT) ~12 – NG(CT & DB)	0.010 lb/MMBtu – (CT) 0.011 lb/MMBtu -(CT/DB) 10% Opacity	Clean Fuels Good Combustion

Notes:

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

DRAFT PERMIT

PERMITTEE:

Florida Power and Light Company
P.O. Box 176
Indiantown, FL 34956

Authorized Representative:
John M. Lindsay, Plant General Manager

FPL Martin Power Plant
Project No. 0850001-010-AC
Air Permit No. PSD-FL-327
SIC No. 4911
Expires: December 30, 2005

PROJECT AND LOCATION

This permit authorizes the construction of Unit 8, a nominal 1150-megawatt "4-on-1" combined cycle unit at the existing Martin Power Plant. The project will utilize two existing 170 MW gas turbine-electrical generator sets and will add two new 170 MW gas turbine-electrical generator sets, four new heat recovery steam generators, a single nominal 470 MW steam turbine-electrical generator, gas-fired fuel heaters, and a mechanical draft cooling tower. The existing Martin Power Plant is located approximately 7 miles north of Indiantown on State Road 710 in Martin County, Florida.

UTM Zone 17; 543.1 km East; 2992.9 km North (Latitude: 27° 03' 1", Longitude: 80° 33' 46")

STATEMENT OF BASIS

This PSD air pollution construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.) and Title 40, Part 52, Section 21 of the Code of Federal Regulations. Pursuant to Chapter 62-17, F.A.C. and Chapter 403 Part II, F.S., the project is also subject to Electrical Power Plant Siting and was therefore processed in accordance with Florida's delegated program for the Prevention of Significant Deterioration (PSD) of Air Quality. The permittee is authorized to install the proposed equipment 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.

CONTENTS

(DRAFT)

Howard L. Rhodes, Director
Division of Air Resources Management

(Date)

FACILITY DESCRIPTION

The existing Martin Power Plant currently consists of six electrical generating units. Fossil fuel-fired steam electric generators Units 1 and 2 (863 MW each) began operation in 1980 and 1981, respectively. Combined cycle gas turbine Units 3A/3B and 4A/4B (430 MW each) began operation in 1994. Existing simple cycle gas turbine Units 8A and 8B (170 MW each) began operation in 2001. Units 8A and 8 B will be incorporated into the new "4 on 1" combined cycle Unit 8, which will consist of two new gas turbine Units 8C and 8D (170 MW each), four heat recovery steam generators, a single steam turbine-electrical generator (470 MW), and a mechanical draft cooling tower. Unit 8 will have a total generating capacity of 1150 MW. After completion of this project, the plant will have a nominal generating capacity of 3610 MW.

NEW AND MODIFIED EMISSIONS UNITS

This permit authorizes construction and installation of the following new emissions units.

ID	Emission Unit Description
011	Unit 8A gas turbine (170 MW) with heat recovery steam generator
012	Unit 8B gas turbine (170 MW) with heat recovery steam generator
013	Gas-fired fuel heaters
017	Unit 8C gas turbine (170 MW) with heat recovery steam generator
018	Unit 8D gas turbine (170 MW) with heat recovery steam generator
019	Mechanical draft cooling tower for Unit 8

Note: Martin Unit 8 consists of four gas turbine-electrical generator sets (Units 8A-8D), four gas-fired heat recovery steam generators (HRSGs), and a single steam-turbine electrical generator.

REGULATORY CLASSIFICATION

Title III: The existing facility is major for hazardous air pollutants (HAPs). This project is not major for HAPs.

Title IV: The facility operates emissions units subject to the acid rain provisions of the Clean Air Act.

Title V: Because potential emissions of at least one regulated pollutant exceed 100 tons per year, the existing facility is a Title V major source of air pollution in accordance with Chapter 62-213, F.A.C. Regulated pollutants include pollutants such as carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), and volatile organic compounds (VOC).

PSD: The project is located in an area designated as "attainment" or "unclassifiable" for each pollutant subject to a National Ambient Air Quality Standard. The facility is considered a "fossil fuel fired steam electric plant of more than 250 million BTU per hour of heat input", which is one of the 28 PSD source categories with the lower PSD applicability threshold of 100 tons per year. Potential emissions of at least one regulated pollutant exceed 100 tons per year. Therefore, the facility is classified as a PSD-major source of air pollution with respect to Rule 62-212.400, F.A.C, the Prevention of Significant Deterioration (PSD) of Air Quality.

NSPS: The following New Source Performance Standards (NSPS) apply to this project: 40 CFR 60, Subpart Da (gas-fired duct burners); 40 CFR 60, Subpart Dc (gas-fired fuel heaters); and 40 CFR 60, Subpart GG (gas turbines).

NESHAP: No emissions units are identified as subject to any National Emissions Standards for Hazardous Air Pollutants (NESHAP).

Siting: The project is subject to Electrical Power Plant Siting in accordance with Chapter 62-17, F.A.C. and Chapter 403, Part II, F.S.

PERMITTING AUTHORITY

All documents related to applications for permits to construct, operate or modify an emissions unit shall be submitted to the Bureau of Air Regulation of the Florida Department of Environmental Protection (DEP) at 2600 Blair Stone Road (MS #5505), Tallahassee, Florida 32399-2400. Copies of all such documents shall also be submitted to the Compliance Authority.

COMPLIANCE AUTHORITY

All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Air Resources Section of the Southeast District Office, Florida Department of Environmental Protection, Post Office Box 15425, West Palm Beach, Florida 33416-5425.

APPENDICES

The following Appendices are attached as part of this permit.

- Appendix A. Citation Format and Definitions
- Appendix BD. Final BACT Determinations and Emissions Standards
- Appendix Da. NSPS Subpart Da Requirements for Gas-Fired Duct Burners
- Appendix Dc. NSPS Subpart Dc Requirements for Gas-Fired Fuel Heaters
- Appendix GC. Construction Permit General Conditions
- Appendix GG. NSPS Subpart GG Requirements for Gas Turbines
- Appendix SC. Standard Conditions

RELEVANT DOCUMENTS

The documents listed below are not a part of this permit; however, they are specifically related to this permitting action and are on file with the Department.

- Permit application received on 02/01/02 and all related completeness correspondence.
- Draft permit package issued on (Draft).
- Comments received from the public, the applicant, the EPA Region 4 Office, and the National Park Service.

1. General Conditions: The permittee shall operate under the attached General Conditions listed in Appendix GC of this permit. General Conditions are binding and enforceable pursuant to Chapter 403 of the Florida Statutes. [Rule 62-4.160, F.A.C.]

2. Applicable Regulations, Forms and Application Procedures: Unless otherwise indicated in this permit, the construction and operation of the subject emissions unit shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of: Chapter 403 of the Florida Statutes (F.S.); Chapters 62-4, 62-204, 62-210, 62-212, 62-213, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.); and the Title 40, Parts 51, 52, 60, 72, 73, and 75 of the Code of Federal Regulations (CFR), adopted by reference in Rule 62-204.800, F.A.C. The terms used in this permit have specific meanings as defined in the applicable chapters of the Florida Administrative Code. 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. Issuance of this permit does not relieve the permittee from compliance with any applicable federal, state, or local permitting or regulations. [Rules 62-204.800, 62-210.300 and 62-210.900, F.A.C.]

3. Construction and Expiration: The permit expiration date includes sufficient time to complete construction, perform required testing, submit test reports, and submit an application for a Title V operation permit to the Department. Approval to construct shall become invalid for any of the following reasons: construction is not commenced within 18 months after issuance of this permit; construction is discontinued for a period of 18 months or more; or 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. In conjunction with an extension of the 18-month period to commence or continue construction, phasing of the project, or an extension of the permit expiration date, the Department may require the permittee to demonstrate the adequacy of any previous determination of Best Available Control Technology (BACT) for emissions units regulated by the project. For good cause, the permittee may request that this PSD air construction permit be extended. Such a request shall be submitted to the Department's Bureau of Air Regulation at least sixty (60) days prior to the expiration of this permit. [Rules 62-4.070(4), 62-4.080, 62-210.300(1), and 62-212.400(6)(b), F.A.C.; 40 CFR 52.21(r)(2); 40 CFR 51.166(j)(4)]

4. New or Additional Conditions: 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.]

5. Modifications: No emissions unit or facility subject to this permit shall be constructed or modified without obtaining an air construction permit from the Department. Such permit shall be obtained prior to beginning construction or modification. [Chapters 62-210 and 62-212, F.A.C.]

6. Application for Title IV Permit: At least 24 months before the date on which the new unit begins serving an electrical generator greater than 25 MW, the permittee shall submit an application for a Title IV Acid Rain Permit to the Department's Bureau of Air Regulation in Tallahassee and a copy to the Region 4 Office of the U.S. Environmental Protection Agency in Atlanta, Georgia. [40 CFR 72]

7. Title V Permit: This permit authorizes construction of the permitted emissions units and initial operation to determine compliance with Department rules. A Title V operation permit is required for regular operation of the permitted emissions unit. The permittee shall apply for a Title V operation permit at least 90 days prior to expiration of this permit, but no later than 180 days after commencing operation. To apply for a Title V operation permit, the applicant shall submit the appropriate application form, compliance test results, and such additional information as the Department may by law require. The application shall be submitted to the Department's Bureau of Air Regulation with a copy to the Compliance Authority. [Rules 62-4.030, 62-4.050, 62-4.220, and Chapter 62-213, F.A.C.]

A. UNIT 8 – "4 ON 1" COMBINED CYCLE GAS TURBINE

This section of the permit addresses the following emissions units.

Emissions Units 011, 012, 017, 018

Description: Emissions units 011, 012, 017, and 018 each consist of a General Electric Model PG7241(FA) gas turbine-electrical generator set, an automated gas turbine control system, an inlet air filtration system, an evaporative inlet air-cooling system, a gas-fired heat recovery steam generator (HRSG), a bypass stack, a HRSG stack, and associated support equipment. In addition, the project also includes a single steam turbine-electrical generator that serves all four gas turbine/HRSG systems.

Fuels: Each gas turbine fires natural gas as the primary fuel and distillate oil as a restricted alternate fuel.

Generating Capacity: Each of the four gas turbine-electrical generator sets has a nominal generating capacity of 170 MW for gas firing (180 MW for oil firing). Exhaust from each gas turbine passes through a separate heat recovery steam generator (HRSG). Steam from each HRSG is delivered to the single steam turbine-electrical generator, which has a nominal capacity of 470 MW. The total nominal generating capacity of the "4 on 1" combined cycle unit is 1150 MW.

Controls: The efficient combustion of natural gas and restricted firing of low sulfur distillate oil minimizes the emissions of CO, PM/PM_{10}, SAM, SO_2 and VOC. Dry low-NOx (DLN) combustion technology for gas firing and water injection for oil firing reduce NOx emissions during simple cycle operation. A selective catalytic reduction (SCR) system in combination with the other NOx controls further reduces NOx emissions during combined cycle operation.

Stack Parameters: Each gas turbine has a bypass stack (80 feet tall and 22.0 feet in diameter) and each heat recovery steam generator has a HRSG stack (120 feet tall and 19.0 feet in diameter). The following summarizes the exhaust characteristics:

			Simple Cycle Operation		Combined Cycle Operation	
Fuel	Heat Input Rate	Compressor Inlet Temp.	Exhaust Temp.	Flow Rate ACFM	Exhaust Temp., °F	Flow Rate ACFM
Gas	1600 MMBtu/hour	59° F	1116° F	2,389,500	202° F	1,004,200
Oil	1811 MMBtu/hour	59° F	1098° F	2,735,300	295° F	1,193,900

Continuous Monitors: Each stack is equipped with continuous emissions monitoring systems (CEMS) to measure and record CO and NOx emissions as well as flue gas oxygen or carbon dioxide content.

APPLICABLE STANDARDS AND REGULATIONS

1. BACT Determinations: Determinations of the Best Available Control Technology (BACT) were made for carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM_{10}), sulfuric acid mist (SAM), and sulfur dioxide (SO_2), and volatile organic compounds (VOC). See Appendix BD of this permit for a summary of the final BACT determinations. [Rule 62-212.400(BACT), F.A.C.]

2. NSPS Requirements: The Department determines that compliance with the BACT emissions performance and monitoring requirements also assures compliance with the New Source Performance Standards for Subpart Da (duct burners) and Subpart GG (gas turbines) in 40 CFR 60. For completeness, the applicable Subpart GG and Subpart Da requirements are summarized in Appendices Dc and GG of this permit. [Rule 62-204.800(7), F.A.C.]

EQUIPMENT

3. Gas Turbine Units 8C and 8D: The permittee is authorized to install, tune, operate, and maintain two new General Electric Model PG7241FA gas turbine-electrical generator sets each with a nominal capacity of 170 MW (EU 017 and 018). Each gas turbine shall include the Speedtronic™ automated gas turbine control system and have dual-fuel capability. Ancillary equipment includes an inlet air filtration system, an evaporative inlet air-cooling system, and a bypass stack for simple cycle operation that is 80 feet tall and 22.0 feet in diameter. The gas turbines will utilize the "hot nozzle" DLN combustors, which require natural gas to be preheated to approximately 290° F before combustion to increase overall unit efficiency. Gas-fired fuel heaters (EU 013) will preheat the natural gas during simple cycle operation and during startup to combined cycle operation. For full combined cycle operation, feedwater heat exchangers will preheat the natural gas. *{Permitting Note: Two existing simple cycle General Electric Model PG7241FA gas turbine-electrical generator sets, Units 8A and 8B (EU 011 and 012), will be incorporated into the "4-on-1" combined cycle Unit 8.}* [Application; Design]

4. Gas Turbine NOx Controls

   a. *DLN Combustion*: The permittee shall operate and maintain the General Electric DLN 2.6 combustion system (or better) to control NOx emissions from each gas turbine when firing natural gas. Prior to the initial emissions performance tests required for each gas turbine, the DLN combustors and automated gas turbine control system shall be tuned to reduce NOx emissions below permitted levels. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations.

   b. *Water Injection*: The permittee shall install, operate, and maintain a water injection system to reduce NOx emissions from each gas turbine when firing distillate oil. Prior to the initial emissions performance tests required for each gas turbine, the water injection system shall be tuned to reduce NOx emissions below permitted levels. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations. The automated control system shall be programmed to establish a water-to-fuel ratio designed to meet the NOx emission standard on a 1-hour basis.

   c. *(SCR) System*: The permittee shall install, tune, operate, and maintain a selective catalytic reduction (SCR) system to control NOx emissions from each gas turbine during combined cycle operation when firing either natural gas or distillate oil. The SCR system consists of an ammonia injection grid, catalyst, aqueous ammonia storage, monitoring and control system, electrical, piping and other ancillary equipment. The SCR system shall be designed and operated to reduce NOx emissions and ammonia slip below the permitted levels. *{Permitting Note: The ammonia tank will store aqueous ammonia having a concentration of less than 20 percent ammonia. In accordance with 40 CFR 60.130, it is not subject to the Chemical Accident Prevention Provisions of 40 CFR 68.}*

   [Design; Rule 62-212.400(BACT), F.A.C.]

5. HRSGs: The permittee is authorized to install, operate, and maintain four new heat recovery steam generators (HRSGs). Each HRSG shall be designed to recover heat energy from one of the four gas turbines (8A-8D) and deliver steam to the steam turbine electrical generator through a common manifold. Each HRSG shall include an exhaust stack that is 120 feet tall and 19.0 feet in diameter. To minimize the number of cold startups to combined cycle operation, each HRSG system shall include a damper in the ductwork before the stack to reduce heat loss during shutdowns. Each HRSG may be equipped with supplemental gas-fired duct burners having a maximum heat input rate of 495 MMBtu per hour (LHV). *{Permitting Note: The four HRSGs deliver steam to a single steam turbine-electrical generator with a nominal capacity of 470 MW.}* [Application; Design]

PERFORMANCE RESTRICTIONS

6. <u>Permitted Capacity - Gas Turbines</u>: The heat input rate to each gas turbine shall not exceed 1600 MMBtu per hour when firing natural gas and 1811 MMBtu per hour when firing distillate oil (based on a compressor inlet air temperature of 59° F, the lower heating value (LHV) of each fuel, and 100% load). Heat input rates will vary depending upon gas turbine characteristics, ambient conditions, alternate methods of operation, and evaporative cooling. The permittee shall provide manufacturer's performance curves (or equations) that correct for site conditions to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department. [Rule 62-210.200(PTE), F.A.C.]
7. <u>Permitted Capacity - HRSG Duct Burners</u>: The total heat input rate to the duct burners for each HRSG shall not exceed 495 MMBtu per hour based on the lower heating value (LHV) of natural gas. Only natural gas shall be fired in the duct burners. [Rule 62-210.200(PTE), F.A.C.]
8. <u>Methods of Operation</u>: Subject to the restrictions and requirements of this permit, the gas turbines may operate under the following methods of operation.
   a. *Hours of Operation*: Subject to the operational restrictions of this permit, the gas turbines may operate throughout the year (8760 hours per year). Restrictions on individual methods of operation are specified below.
   b. *Authorized Fuels*: Each gas turbine shall fire natural gas as the primary fuel, which shall contain no more than 2.0 grains of sulfur per 100 standard cubic feet of natural gas. As a restricted alternate fuel, each gas turbine may fire No. 2 distillate oil (or a superior grade) containing no more than 0.05% sulfur by weight. Each gas turbine shall fire no more than 500 hours of distillate oil during any consecutive 12 months.
   c. *Simple Cycle Operation*: Each gas turbine may operate individually in simple cycle mode to produce only direct, shaft-driven electrical power subject to the following operational restrictions.
      (1) Each gas turbine shall operate in simple cycle mode for no more than 3390 hours during any consecutive 12 months.
      (2) After demonstrating initial compliance in combined cycle mode, the combined group of four gas turbines shall operate in simple cycle mode for no more than an average of 1000 hours during any consecutive 12 months.
   d. *Combined Cycle Operation*: Each gas turbine/HRSG system may operate to produce direct, shaft-driven electrical power and deliver steam to the steam turbine-electrical generator to produce steam-generated electrical power as a four-on-one combined cycle unit subject to the restrictions of this permit. In accordance with the manufacturer's specifications, the SCR system shall be on line and functioning properly during combined cycle operation.
   e. *Inlet Fogging*: In accordance with the manufacturer's recommendations and appropriate ambient conditions, the evaporative cooling system may be operated to reduce the compressor inlet air temperature and provide additional direct, shaft-driven electrical power. This method of operation is commonly referred to as "fogging" and may be used in either simple cycle or combined cycle modes.
   f. *Peaking*: When firing natural gas, each gas turbine may operate in a high-temperature peaking mode to generate additional direct, shaft-driven electrical power to respond to peak demands. During any consecutive 12 months, each gas turbine shall operate while in the peaking mode for no more than 60 hours of simple cycle operation and no more than 400 hours of combined cycle operation.

g. *Power Augmentation*: When firing natural gas in either simple cycle or combined cycle modes, steam may be injected into each gas turbine to generate additional direct, shaft-driven electrical power to respond to peak demands. To qualify as "power augmentation", the combustion turbine must operate at a load of 95% or greater than that of the manufacturer's maximum base load rate adjusted for the compressor inlet air conditions. Prior to activating and after deactivating the power augmentation mode, the operator shall log the date, time, and new mode of operation. Each gas turbine shall operate in the power augmentation mode for no more than 400 hours during any consecutive 12 months. The gas turbines shall not operate simultaneously in peaking and power augmentation modes. In addition, total combined operation of power augmentation and peaking modes shall not exceed 400 hours during any consecutive 12 months.

h. *Combined Cycle Operation with Duct Firing*: When firing natural gas and operating in combined cycle mode, each gas turbine/HRSG system may fire natural gas in the duct burners to provide additional steam-generated electrical power. Each HRSG shall fire the duct burners no more than 2880 hours during any consecutive 12 months.

[Application; Rules 62-210.200(PTE) and 62-212.400(BACT), F.A.C.]

EMISSIONS STANDARDS

9. Emissions Standards: Emissions from each gas turbine shall not exceed the following standards.

Pollutant	Fuel	Method of Operation	Initial		CEMS
			ppmvd @ 15% O_2	lb/hour	ppmvd @ 15% O_2
CO [a]	Oil	Simple or Combined Cycle	14.4, 3-hr	64.7	15.0, 24-hr
	Gas	Simple or Combined Cycle	7.4, 3-hr	27.5	8.0, 24-hr
		Combined Cycle w/DB	7.4, 3-hr	37.5	8.0, 24-hr
		Simple or Combined Cycle w/PA	12.0, 3-hr	45.0	12.0, 24-hr
		Combined Cycle w/DB+PA	12.0, 3-hr	55.6	12.0, 24-hr
NOx [b]	Oil	Simple Cycle	42.0, 3-hr	319.2	42.0, 3-hr
		Combined Cycle – SCR	10.0, 3-hr	76.0	10.0, 24-hr
	Gas	Simple Cycle	9.0, 3-hr	58.7	9.0, 24-hr
		Simple Cycle w/PA	NA	(76.2)	12.0, 1-hr
		Simple Cycle w/Peaking	NA	(101.3)	15.0, 1-hr
		Combined Cycle – SCR	2.5, 3-hr	16.3	2.5, 24-hr
		Combined Cycle w/DB – SCR	2.5, 3-hr	22.1	2.5, 24-hr
PM/PM_{10} [c]	Oil/Gas	Simple or Combined Cycle	Fuel Specifications		
		Simple or Combined Cycle	Visible emissions shall not exceed 10% opacity for each 6-minute average as determined by EPA Method 9 observations.		
SAM/SO_2 [d]	Oil/Gas	Simple or Combined Cycle	Fuel Specifications		
VOC [e]	Oil	Simple or Combined Cycle	2.5, 3-hr	6.0	NA
	Gas	Simple or Combined Cycle	1.3, 3-hr	2.8	NA
		Combined Cycle, w/DB or PA	4.0, 3-hr	9.2	NA
Ammonia [f]	Oil/Gas	Combined Cycle – SCR	5.0, 3-hr	NA	NA

Note: "DB" means duct burning. "PA" means power augmentation.

a. Compliance with the CO standards shall be demonstrated based on data collected by the required CEMS. Compliance may also be determined by EPA Method 10. Compliance with the 24-hour CO standards shall be determined separately for each method of operation based on the hours of operation for each method. *{Permitting Note: A 24-hour compliance average may be based on as little as 1-hour of CEMS data or as much as 24-hours of CEMS data.}*

b. Compliance with the NOx standards shall be demonstrated based on data collected by the required CEMS. Compliance may also be determined by EPA Method 7E or 20. NOx mass emission rates are defined as oxides of nitrogen expressed as NO_2. Compliance with the NOx standard for simple cycle operation with peaking or power augmentation shall be demonstrated on an hour-to-hour basis with CEMS data. CEMS data collected during simple cycle peaking or power augmentation shall be excluded from the data used to demonstrate compliance with the 24-hour standard for normal operation. *{Permitting Note: The "lb/hour" rates for simple cycle peaking or power augmentation are for informational purposes only.}*

c. The fuel specifications established in Condition No. 8 of this section combined with the efficient combustion design and operation of each gas turbine represents the Best Available Control Technology (BACT) determination for PM/PM_{10} emissions. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion. *{Permitting Note: PM_{10} emissions for gas firing are estimated at 9 lb/hour for simple cycle operation, 11 lb/hour for combined cycle operation, and 17 lb/hour for combined cycle operation with duct burning. PM_{10} emissions for oil firing are estimated at 17 lb/hour for simple cycle operation and 37 lb/hour for combined cycle operation.}*

d. The fuel sulfur specifications in Condition No. 8 of this section effectively limit the potential emissions of SAM and SO_2 from the gas turbines and represent the Best Available Control Technology (BACT) determination for these pollutants. Compliance with the fuel sulfur specifications shall be determined by the requirements in Condition No. 28 of this section. *{Permitting Note: SO_2 emissions for gas firing are estimated at 9.8 lb/hour for simple and combined cycle operation and 12.8 lb/hour for combined cycle operation with duct burning. SO_2 emissions for oil firing are estimated at 99 lb/hour for simple and combined cycle operation. SAM emissions are estimated to be less than 10% of the SO_2 emissions.}*

e. Compliance with the VOC standards shall be demonstrated by conducting tests in accordance with EPA Method 25A. Optionally, EPA Method 18 may be also be performed to deduct emissions of methane and ethane. The emission standards are based on VOC measured as methane.

f. Compliance with the ammonia slip standard shall be demonstrated by conducting tests in accordance with EPA Method CTC-027.

[Rule 62-212.400(BACT), F.A.C.]

10. <u>Combined Cycle Operation With Dump Condenser</u>: If the steam-electrical turbine generator is off line, the permittee is authorized to operate the gas turbine/HRSG systems by transferring steam to a dump condenser. Operation with a dump condenser must still meet the standards established for combined cycle operation with ammonia injection. *{Permitting Note: Although this method of operation is inefficient, it may be preferable due to the time necessary to shutdown, cool, and prepare the units for simple cycle operation.}* [Application]

11. <u>Duct Burners</u>: The duct burners are also subject to the provisions of Subpart Da of the New Source Performance Standards in 40 CFR 60, which are summarized in Appendix Da. [Subpart Da, 40 CFR 60]

PROJECT PHASE-IN

12. Existing Simple Cycle Units: For existing Units 8A and 8B (EU 011 and 012), this PSD permit shall replace and supersede previously issued PSD permit (No. PSD-FL-286) upon commencement of the initial steam blows. [Rule 62-4.070(3), F.A.C.]

EXCESS EMISSIONS

13. Operating Procedures: The Best Available Control Technology (BACT) determinations established by this permit rely on "good operating practices" to reduce emissions. Therefore, all operators and supervisors shall be properly trained to operate and maintain the gas turbines, HRSGs, and pollution control systems in accordance with the guidelines and procedures established by each manufacturer. The training shall include good operating practices as well as methods of minimizing excess emissions. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

14. Excess Emissions Prohibited: 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. All such preventable emissions shall be included in any compliance determinations based on CEMS data. [Rule 62-210.700(4), F.A.C.]

15. Alternate Visible Emissions Standard: Visible emissions due to startups, shutdowns, and malfunctions shall not exceed 10% opacity except for up to ten, 6-minute averaging periods during a calendar day, which shall not exceed 20% opacity. [Rule 62-212.400(BACT), F.A.C.]

16. Excess Emissions Allowed: As specified in this condition, excess emissions resulting from startup, shutdown, and documented malfunctions are allowed provided that operators employ the best operational practices to minimize the amount and duration of emissions during such incidents. For each gas turbine/HRSG system, excess emissions resulting from startup, shutdown, or documented malfunctions occurrences shall in no case exceed two hours in any 24-hour period except for the following specific cases.

    a. For warm startup to combined cycle operation, up to three hours of excess emissions are allowed. "Warm startup" is defined as a startup to combined cycle operation following a shutdown lasting at least 24 hours.

    b. For cold startup to combined cycle operation, up to four hours of excess emissions are allowed. "Cold startup" is defined as a startup to combined cycle operation following a shutdown lasting at least 48 hours.

    c. For shutdown from combined cycle operation, up to three hours of excess emissions are allowed.

    For days with simple cycle operation, excess emissions shall not exceed three hours in any 24-hour period due to all combined occurrences of startups, shutdowns, and malfunctions. For days with combined cycle operation, excess emissions shall not exceed four hours in any 24-hour period due to all combined occurrences of startups, shutdowns, and malfunctions. For startup to combined cycle operation, ammonia injection shall begin as soon as operation of the gas turbine/HRSG system achieves the operating parameters specified by the manufacturer. As authorized by Rule 62-210.700(5), F.A.C., the above conditions allow excess emissions only for specifically defined periods of startup, shutdown, and documented malfunction of the gas turbines. [Design; Rules 62-212.400(BACT) and 62-210.700, F.A.C.]

17. Initial Steam Blows: Prior to completing the conversion from simple cycle to combined cycle operation, the permittee is authorized to operate each gas turbine at loads below 50% for the purpose of cleaning the HRSG piping system and piping connecting the HRSG to the steam turbine. Prior to conducting any steam blows, the permittee shall submit a proposed schedule. On the first day of conducting steam blows, the permittee shall notify the Compliance Authority that the process has begun. The permittee shall complete

this process within 90 days of conducting the initial steam blow. During the steam blows, the following conditions apply:

a. The permittee shall take all precautions to minimize the extent and duration of excess emissions.

b. Each gas turbine shall fire only natural gas and each CEMS shall be on line and functioning properly.

c. CO and NOx emissions may exceed the BACT limits specified in this permit; however, NOx emissions shall not exceed the NSPS Subpart GG limit of 110 ppmvd corrected to 15% oxygen based on a 24-hour block average. If the NSPS standard is exceeded, the permittee shall notify the Compliance Authority within 24-hours of the incident.

Within 30 days of completing the initial steam blows, the permittee shall submit a report to the Bureau of Air Regulation and the Compliance Authority summarizing the daily emissions resulting from each steam blow. *{Permitting Note: It is estimated that steam blows will occur intermittently over a 30-day period for each gas turbine/HRSG system followed by a similar 60-day period of intermittent steam blows for the common piping system serving the four interconnected combined cycle units. It is not expected that steam blows would occur every day during these periods.}* [Application]

18. DLN Tuning: CEMS data collected during initial or other major DLN tuning sessions shall be excluded from the CEMS compliance demonstration provided the tuning session is performed in accordance with the manufacturer's specifications. A "major tuning session" would occur after completion of initial construction, a combustor change-out, a major repair or maintenance to a combustor, or other similar circumstances. Prior to performing any major tuning session, the permittee shall provide the Compliance Authority with an advance notice that details the activity and proposed tuning schedule. The notice may be by telephone, facsimile transmittal, or electronic mail. [Design; Rule 62-4.070(3), F.A.C.]

EMISSIONS PERFORMANCE TESTING

19. Test Methods: Any required tests shall be performed in accordance with the following reference methods.

Method	Description of Method and Comments
CTM-027	Procedure for Collection and Analysis of Ammonia in Stationary Source {Notes: This is an EPA conditional test method. The minimum detection limit shall be 1 ppm.}
5	Determination of Particulate Matter Emissions from Stationary Sources
7E	Determination of Nitrogen Oxide Emissions from Stationary Sources
9	Visual Determination of the Opacity of Emissions from Stationary Sources
10	Determination of Carbon Monoxide Emissions from Stationary Sources {Notes: The method shall be based on a continuous sampling train.}
18	Measurement of Gaseous Organic Compound Emissions by Gas Chromatography {Note: EPA Method 18 may be used (optional) concurrently with EPA Method 25A to deduct emissions of methane and ethane from the measured VOC emissions.}
20	Determination of Nitrogen Oxides, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines
25A	Determination of Volatile Organic Concentrations

Method CTM-027 is published on EPA's Technology Transfer Network Web Site at "http://www.epa.gov/ttn/emc/ctm.html". The other methods are described in Appendix A of 40 CFR 60, adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used unless prior written approval is received from the Department. [Rules 62-204.800, F.A.C.; 40 CFR 60, Appendix A]

20. Initial Compliance Determinations: Each gas turbine shall be stack tested to demonstrate initial compliance with the emission standards for CO, NOx, VOC, visible emissions, and ammonia slip. The tests shall be conducted within 60 days after achieving at least 90% of the maximum permitted capacity for each unit configuration (i.e., simple cycle and combined cycle operation), but not later than 180 days after the initial startup of each unit configuration. Each unit shall be tested when firing natural gas and distillate oil. CEMS data collected during the required Relative Accuracy Test Assessments (RATA) may be used to demonstrate compliance with the initial 3-hour CO and NOx standards. With appropriate flow measurements and calculations, CEMS data may also be used to demonstrate compliance with the CO and NOx mass emissions standards. CO and NOx emissions recorded by the CEMS shall also be reported for each run during tests for visible emissions, VOC and ammonia slip. The Department may require the permittee to conduct initial tests after the replacement or repair of any air pollution control equipment, such as the SCR catalyst, DLN combustors, etc. [Rule 62-297.310(7)(a)1., F.A.C.]

21. Continuous Compliance: The permittee shall demonstrate continuous compliance with the CO and NOx emissions standards based on data collected by the certified CEMS. Within 45 days of conducting any Relative Accuracy Test Assessments (RATA) on a CEMS, the permittee shall submit a report to the Compliance Authority summarizing results of the RATA. Compliance with the CO emission standards also serves as an indicator of efficient fuel combustion, which reduces emissions of particulate matter and volatile organic compounds. [Rule 62-212.400 (BACT), F.A.C.]

22. Annual Compliance Tests: During each federal fiscal year (October 1st to September 30th), each gas turbine shall be tested to demonstrate compliance with the emission standards for visible emissions and ammonia slip. NOx emissions recorded by the CEMS shall be reported for each ammonia slip test run. CO emissions recorded by the CEMS shall be reported for the visible emissions observation period. *{Permitting Note: After initial compliance with the VOC standards is demonstrated, annual compliance tests for VOC emissions are not required. Compliance with the continuously monitored CO standards shall indicate efficient combustion and low VOC emissions.}* [Rules 62-212.400 (BACT) and 62-297.310(7)(a)4., F.A.C.]

CONTINUOUS MONITORING REQUIREMENTS

23. CEM Systems: The permittee shall install, calibrate, maintain, and operate continuous emission monitoring systems (CEMS) to measure and record the emissions of CO and NOx from the combined cycle gas turbine in a manner sufficient to demonstrate continuous compliance with the CEMS emission standards of this section. Each monitoring system shall be installed, calibrated, and properly functioning prior to the initial performance tests and commencement of commercial operation. Within one working day of discovering emissions in excess of a CO or NOx standard, the permittee shall contact the Compliance Authority.

    a. *CO Monitors.* The CO monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, and the Data Assessment Report of Section 7 shall be made each calendar quarter, and reported semiannually to the Compliance Authority. The RATA tests required for the CO monitor shall be performed using EPA Method 10 in Appendix A of 40 CFR 60 and shall be based on a continuous sampling train. The CO monitor shall have multi-span capability with appropriate spans established for the methods of operation (simple cycle gas firing, combined cycle gas firing, simple cycle oil firing, combined cycle oil firing, etc.). {Permitting Note: The alternate standards for steam blows will require even higher span values.}

    b. *NOx Monitors.* Each NOx monitor shall be certified pursuant to 40 CFR Part 75 and shall be operated and maintained in accordance with the applicable requirements of 40 CFR Part 75, Subparts B and C. Record keeping and reporting shall be conducted pursuant to 40 CFR Part 75, Subparts F and G. The RATA tests required for the NO_X monitor shall be performed using EPA Method 20 or 7E in Appendix

A of 40 CFR 60. The NOx monitor shall have multi-span capability with appropriate spans established for the methods of operation (simple cycle gas firing, combined cycle gas firing, simple cycle oil firing, combined cycle oil firing, etc.). {Permitting Note: The alternate standards for steam blows will require even higher span values.}

c. *O_2 or CO_2 Monitors.* The oxygen (O_2) content or carbon dioxide (CO_2) content of the flue gas shall also be monitored at the location where CO and/or NOx are monitored to correct the measured emissions rates to 15% oxygen. If a CO_2 monitor is installed, the oxygen content of the flue gas shall be calculated by the CEMS using F-factors that are appropriate for the fuel fired. Each monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 3. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, and the Data Assessment Report of Section 7 shall be made each calendar quarter, and reported semiannually to the Compliance Authority. The RATA tests required for the O_2 or CO_2 monitors shall be performed using EPA Method 3B, of Appendix A of 40 CFR 60.

d. *1-Hour Block Averages.* Hourly average values shall begin at the top of each hour. Each hourly average value shall be computed using at least one data point in each fifteen-minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, an hourly value shall be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour). If less than two such data points are available, the hourly average value is not valid. The permittee shall use all valid measurements or data points collected during an hour to calculate the hourly average values. The CEMS shall be designed and operated to sample, analyze, and record data evenly spaced over an hour. If the CEMS measures concentration on a wet basis, the CEM system shall include provisions to determine the moisture content of the exhaust gas and an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Alternatively, the owner or operator may develop through manual stack test measurements a curve of moisture contents in the exhaust gas versus load for each allowable fuel, and use these typical values in an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Final results of the CEMS shall be expressed as ppmvd corrected to 15% oxygen. The CEMS shall be used to demonstrate compliance with the CEMS emission standards for CO and NOx as specified in this permit. Upon request by the Department, the CEMS emission rates shall be corrected to ISO conditions to demonstrate compliance with the applicable standards of 40 CFR 60.332.

e. *3-hour Block Averages*: For oil firing during simple cycle operation, the 3-hour block average shall be calculated from three consecutive hourly average emission rate values. For purposes of determining compliance with the CEMS emission standards of this permit, missing (or excluded) data shall not be substituted. Instead, the 3-hour block average shall be determined using the remaining hourly data in the 3-hour block. [Rule 62-212.400(BACT), F.A.C.]

f. *24-hour Block Averages*: A 24-hour block shall begin at midnight of each operating day and shall be calculated from 24 consecutive hourly average emission rate values. If a unit operates less than 24 hours during the block, the 24-hour block average shall be the average of available valid hourly average emission rate values for the 24-hour block. For purposes of determining compliance with the 24-hour CEMS standards, missing (or excluded) data shall not be substituted. Instead, the 24-hour block average shall be determined using the remaining hourly data in the 24-hour block. {Permitting Note: There may be more than one 24-hour compliance demonstration for CO and NOx emissions depending on the use of alternate methods of operation. [Rule 62-212.400(BACT), F.A.C.]

g. *Data Exclusion.* Each CEMS shall monitor and record emissions during all operations including all episodes of startup, shutdown, and malfunction. CEMS emissions data recorded during such episodes may be excluded from the corresponding CEMS compliance demonstration subject to the provisions of

Condition No. 16 of this section. All periods of data excluded shall be consecutive for each such episode. The permittee shall minimize the duration of data excluded for such episodes to the extent practicable. Data recorded during such episodes shall not be excluded if the episode was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented. Best operational practices shall be used to minimize hourly emissions that occur during such episodes. Emissions of any quantity or duration that occur entirely or in part from poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented, shall be prohibited.

h. *Availability*. Monitor availability for the CEMS shall be 95% or greater in any calendar quarter. The quarterly permit excess emissions report shall be used to demonstrate monitor availability. In the event 95% availability is not achieved, the permittee shall provide the Department with a report identifying the problems in achieving 95% availability and a plan of corrective actions that will be taken to achieve 95% availability. The permittee shall implement the reported corrective actions within the next calendar quarter. Failure to take corrective actions or continued failure to achieve the minimum monitor availability shall be violations of this permit.

{Permitting Note: Compliance with these requirements ensure compliance with the other applicable CEM system requirements such as: NSPS Subpart GG; Rule 62-297.520, F.A.C.; 40 CFR 60.7(a)(5) and 40 CFR 60.13; 40 CFR Part 51, Appendix P; 40 CFR 60, Appendix B - Performance Specifications; and 40 CFR 60, Appendix F - Quality Assurance Procedures.} [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

24. Water Injection Monitoring Requirements: In accordance with the manufacturer's specifications, the permittee shall install, calibrate, operate and maintain a monitoring system to continuously measure and record the water-to-fuel ratio when firing distillate oil. The permittee shall document the water-to-fuel ratio required to meet permitted emissions levels over the range of load conditions allowed by this permit. During NOx monitor downtimes or malfunctions, the permittee shall operate at the water-to-fuel ratio that is consistent with the documented flow rate for the gas turbine load condition. {Permitting Note: The water-to-fuel ratio at maximum load to achieve the NOx standards during simple cycle oil firing is approximately 1.10 or a water injection rate of approximately 101,000 pounds per hour.} [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

25. Ammonia Monitoring Requirements: In accordance with the manufacturer's specifications, the permittee shall install, calibrate, operate and maintain an ammonia flow meter to measure and record the ammonia injection rate to the SCR system. The permittee shall document the general range of ammonia flow rates required to meet permitted emissions levels over the range of load conditions allowed by this permit by comparing NOx emissions recorded by the CEM system with ammonia flow rates recorded using the ammonia flow meter. During NOx monitor downtimes or malfunctions, the permittee shall operate at the ammonia flow rate that is consistent with the documented flow rate for the combustion turbine load condition. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

RECORDS AND REPORTS

26. Monitoring of Capacity: To demonstrate compliance with the permitted capacities, the permittee shall monitor and record the operating rate of each combined cycle gas turbine on a daily average basis, considering the number of hours of operation during each day (including the times of startup, shutdown and malfunction). Such monitoring shall be made using a monitoring component of the CEM system required above, or by monitoring daily rates of consumption and heat content of each allowable fuel in accordance with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

27. Monthly Operations Summary: By the fifth calendar day of each month, the permittee shall record the following for each fuel in a written or electronic log for each gas turbine for the previous month of

operation: fuel consumption, hours of operation, hours of power augmentation, hours of peaking, hours of duct firing, and the updated 12-month rolling totals for each. Information recorded and stored as an electronic file shall be available for inspection and printing within at least three days of a request by the Department. The fuel consumption shall be monitored in accordance with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

28. Fuel Sulfur Records: The permittee shall demonstrate compliance with the fuel sulfur limits specified in this permit by maintaining the following records of the sulfur contents.

    a. Compliance with the fuel sulfur limit for natural gas shall be demonstrated by keeping reports obtained from the vendor indicating the average sulfur content of the natural gas being supplied from the pipeline for each month of operation. Methods for determining the sulfur content of the natural gas shall be ASTM methods D4084-82, D3246-81 or more recent versions.

    b. Compliance with the distillate oil sulfur limit shall be demonstrated by taking a sample, analyzing the sample for fuel sulfur, and reporting the results to each Compliance Authority before initial startup. Sampling the fuel oil sulfur content shall be conducted in accordance with ASTM D4057-88, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, and one of the following test methods for sulfur in petroleum products: ASTM D129-91, ASTM D1552-90, ASTM D2622-94, or ASTM D4294-90. More recent versions of these methods may be used. For each subsequent fuel delivery, the permittee shall maintain a permanent file of the certified fuel sulfur analysis from the fuel vendor. At the request of a Compliance Authority, the permittee shall perform additional sampling and analysis for the fuel sulfur content.

    The above methods shall be used to determine the fuel sulfur content in conjunction with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-4.160(15), F.A.C.]

29. Excess Emissions Notification: If a CEMS reports emissions in excess of an emissions standard or the permittee observes visible emissions in excess of a standard, the permittee shall notify the Compliance Authority within one working day of occurrence. The notification shall include a preliminary report of: the nature, extent, and duration of the emissions; the probable cause of the emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident. [Rule 62-210.700, F.A.C.]

30. Semiannual NSPS Excess Emissions Report: In accordance with 40 CFR 60.7(d), the permittee shall submit a report to the Compliance Authority summarizing any emissions in excess of the NSPS standards within 30 days following the end of each calendar quarter. For purposes of reporting emissions in excess of NSPS Subpart GG, excess emissions from the gas turbine are defined as: any CEMS hourly average value exceeding the NSPS NOx emission standard identified in Appendix GG; and any daily period during which the sulfur content of the fuel being fired in the gas turbine exceeds the NSPS standard identified in Appendix GG. For purposes of reporting emissions in excess of NSPS Subpart Da, excess emissions from duct firing are defined as: NOx or PM emissions in excess of the NSPS standards except during periods of startup, shutdown, or malfunction; and SO_2 emissions in excess of the NSPS standards except during startup or shutdown. [40 CFR 60.7]

31. Quarterly Permit Excess Emission Report: Within 30 days following the end of each quarter, the permittee shall submit a report to the Compliance Authority summarizing periods of excess CO and NOx emissions. Such information shall also be summarized for simple/combined cycle startups, simple/combined cycle shutdowns, malfunctions, and major tuning sessions. In addition, the report shall summarize the CEMS systems monitor availability for the previous quarter. [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C.; and 40 CFR 60.7]

B. GAS-FIRED FUEL HEATERS

This section of the permit addresses the following emissions units.

ID	Emission Unit Description
013	Four gas-fired fuel heaters, 22 MMBtu/hour each

APPLICABLE REQUIREMENTS

1. NSPS Requirements: The gas-fired fuel heaters are subject to the New Source Performance Standards for Small Industrial-Commercial-Institutional Steam Generating Units specified in Subpart Dc of 40 CFR 60. The units are subject to the record keeping and reporting requirements of this regulation, which are summarized in Appendix Dc of this permit. [Rule 62-204.800(7), F.A.C.; 40 CFR 60, Subpart Dc]

EQUIPMENT

2. Gas-Fired Fuel Heaters: The permittee is authorized to install two new 22 MMBtu per hour (LHV) fuel heaters. *{Permitting Note: The two new units will be added to two existing units under EU 013. The gas-fired fuel heaters heat the natural gas prior to firing in the "hot nozzle" dry low NOx combustors to increase cycle efficiency. The fuel heaters operate continuously during simple cycle operation and for startup to combined cycle operation. Once combined cycle operation is established, the fuel heaters are shut down and a small heat exchanger in the HRSG exhaust is used to preheat the natural gas prior to combustion in the gas turbines.}* [Application; Design]

PERFORMANCE REQUIREMENTS

3. Permitted Capacity: Based on the lower heating value (LHV) of natural gas, each gas-fired fuel heater shall not exceed 22 MMBtu per hour. [Application; Rule 62-210.200(PTE), F.A.C.]

4. Authorized Fuel: Each fuel heater shall fire only natural gas, which shall contain no more than 2.0 grains of sulfur per 100 standard cubic feet of natural gas. [Rules 62-212.400(BACT) and 62-210.200(PTE), F.A.C.]

EMISSIONS STANDARDS

5. Visible Emissions: Visible emissions from each gas-fired fuel heater shall not exceed 10% opacity (6-minute block average) except for one 6-minute block average, which shall not exceed 20% opacity. [Rule 62-212.400(BACT), F.A.C.]

TESTING, RECORDS, AND REPORTING

6. Fuel Consumption: Equipment shall be installed and maintained to monitor the consumption of natural gas for each fuel heater. The monitoring system shall be capable of totaling the daily natural gas consumption. Natural gas consumption shall be reported in the Annual Operating Report. [40 CFR 60, Subpart Dc; Rule 62-210.370(2), F.A.C.

7. Fuel Sulfur: Compliance with the fuel sulfur limit for natural gas shall be demonstrated by keeping reports obtained from the vendor indicating the average sulfur content of the natural gas being supplied from the pipeline for each month of operation. Methods for determining the sulfur content of the natural gas shall be ASTM methods D4084-82, D3246-81 or more recent versions. [Rule 62-4.070(3), F.A.C.]

8. Visible Emissions Tests: To determine compliance with the visible emissions standard, the permittee shall conduct testing in accordance with EPA Method 9. Initial compliance tests shall be conducted within 60 days of initial startup. Annual tests shall be conducted during each federal fiscal year. The permittee shall notify the Compliance Authority of scheduled tests at least 15 days in advance. Test results shall be submitted to the Compliance Authority within 45 days of conducting the tests. [40 CFR 60, Appendix A; Rules 62-204.800(7), 62-297.310(7)(a)9, 62-297.310(8)(c), F.A.C.]

C. COOLING TOWER

This section of the permit addresses the following new emissions unit.

ID	Emission Unit Description
020	18-cell mechanical draft cooling tower

EQUIPMENT

1. Cooling Tower: The permittee is authorized to install one new 18-cell mechanical draft cooling tower with the following design characteristics: a circulating water flow rate of 310,000 gpm; design hot/cold water temperatures of 104° F/90° F; a design air flow rate of 1,386,055 per cell; a liquid-to-gas air flow ratio of 1.4; and drift eliminators with a drift rate of no more than 0.001 percent. The permittee shall submit the final design details within 60 days of selecting the vendor. [Application; Design]

EMISSIONS AND PERFORMANCE REQUIREMENTS

2. Drift Rate: The cooling tower shall be designed, operated, and maintained to reduce the drift rate to no more than 0.001 percent of the circulating water flow rate. *{Permitting Note: This work practice standard is established as BACT for PM/PM_{10} emissions from the cooling tower. Based on this design criteria, potential emissions are expected to be less than 34 tons of PM per year and less than 10 tons of PM_{10} per year. Actual emissions are expected be less than half these rates.}*. [Rule 62-212.400(BACT), F.A.C.]

SECTION IV. APPENDICES

CONTENTS

CITATION FORMAT AND DEFINITIONS

The following examples illustrate the format used in the permit to identify applicable permitting actions and regulations.

REFERENCES TO PREVIOUS PERMITTING ACTIONS

Old Permit Numbers

Example: Permit No. AC50-123456 or Air Permit No. AO50-123456

Where: "AC" identifies the permit as an Air Construction Permit
"AO" identifies the permit as an Air Operation Permit
"123456" identifies the specific permit project number

New Permit Numbers

Example: Permit Nos. 099-2222-001-AC, 099-2222-001-AF, 099-2222-001-AO, or 099-2222-001-AV

Where: "099" represents the specific county ID number in which the project is located
"2222" represents the specific facility ID number
"001"identifies the specific permit project
"AC" identifies the permit as an air construction permit
"AF" identifies the permit as a minor federally enforceable state operation permit
"AO" identifies the permit as a minor source air operation permit
"AV" identifies the permit as a Title V Major Source Air Operation Permit

PSD Permit Numbers

Example: Permit No. PSD-FL-317

Where: "PSD" means issued pursuant to the Prevention of Significant Deterioration of Air Quality
"FL" means that the permit was issued by the State of Florida
"317" identifies the specific permit project

RULE CITATION FORMATS

Florida Administrative Code (F.A.C.)

Example: [Rule 62-213.205, F.A.C.]

Means: Title 62, Chapter 213, Rule 205 of the Florida Administrative Code

Code of Federal Regulations (CFR)

Example: [40 CRF 60.7]

Means: Title 40, Part 60, Section 7

DEFINITIONS [RULE 62-210.200, F.A.C.]

(119) Excess Emissions - Emissions of pollutants in excess of those allowed by any applicable air pollution rule of the Department, or by a permit issued pursuant to any such rule or Chapter 62-4, F.A.C. The term applies only to conditions which occur during startup, shutdown, soot blowing, load changing or malfunction.

(179) Malfunction - Any unavoidable mechanical and/or electrical failure of air pollution control equipment or process equipment or of a process resulting in operation in an abnormal or unusual manner.

(258) Shutdown - The cessation of the operation of an emissions unit for any purpose.

(275) Startup - The commencement of operation of any emissions unit which has shut down or ceased operation for a period of time sufficient to cause temperature, pressure, chemical or pollution control device imbalances, which result in excess emissions.

FINAL BACT DETERMINATIONS AND EMISSIONS STANDARDS

OVERVIEW

The project added an 1150 MW "4-on-1" combined cycle gas turbine system to the existing FPL Martin Power Plant. PSD-significant emissions increases required determinations of the Best Available Control Technology (BACT) for carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM_{10}), sulfuric acid mist (SAM), and sulfur dioxide (SO_2), and volatile organic compounds (VOC).

BACT CONTROL TECHNOLOGIES

The Department reviewed available control technologies for each pollutant resulting in a PSD-significant increase. The Department's technical review and rationale for the BACT determinations are presented in the "Technical Evaluation and Preliminary Determination" issued the draft permit package. The following summarizes the control technologies upon which the Department's final BACT determinations are based.

<u>BACT for CO and VOC Emissions</u>

Good Combustion and Operating Practices: BACT for CO and VOC emissions is the efficient combustion of fuels at high temperatures associated with good combustion design and operating practices. General Electric's dual-fuel combustors have demonstrated very low CO and VOC emissions while simultaneously reducing NOx emissions for gas and oil firing.

<u>BACT for NOx Emissions</u>

DLN Combustion: When firing natural gas under simple cycle mode, BACT for NOx emissions is the operation of General Electric's dry low-NOx (DLN) combustion system. The efficient fuel combustion and thorough mixing of the gas stream reduces hot and cold spots surrounding the combustion zone. The full lean premix combustion results in NOx emissions less than 9 ppmvd when firing natural gas. The Speedtronic™ control system continuously monitors performance parameters and adjusts for efficient operation. The control system also provides for quick automated startups, lean pre-mix combustion performance, and controlled shutdowns.

Wet Injection: When firing distillate oil under simple cycle mode, BACT for NOx emissions is the operation of General Electric's dual-fuel combustor with wet injection designed to reduce the flame temperature and lower NOx emissions.

SCR: When firing natural gas or distillate oil in combined cycle mode, BACT for NOx emissions is the operation of the selective catalytic reduction (SCR) system in conjunction with DLN combustion and wet injection. Ammonia injected into the exhaust gas stream combines with NOx in a reduction action across a catalyst bed to form nitrogen and water. The catalyst bed is located after the HRSG, which reduces exhaust temperatures to the appropriate operating range of the catalyst material. A properly designed SCR system will achieve at least 72% reduction with an ammonia slip of no more than 5 ppmvd.

<u>BACT for PM, SAM, and SO_2 Emissions</u>

Clean Fuels: BACT for PM, SAM, and SO_2 emissions is the use of natural gas as the primary fuel (≤ 2.0 grains of sulfur per 100 standard cubic feet of natural gas) and restricted use of very low sulfur distillate oil (≤ 0.05% sulfur by weight). These fuels are readily combustible and contain little ash, sulfur, or other contaminants.

BACT STANDARDS

The following summarizes the final Best Available Control Technology determinations for this project in accordance with Rule 62-212.400(BACT), F.A.C.

<u>Gas-Fired Fuel Heaters</u>: BACT for emissions of CO, NOx, PM/PM10, SAM, SO2, and VOC from the gas-fired fuel heaters is the efficient combustion of natural gas and a visible emissions standard of 10% opacity except for one 6-minute period not to exceed 20% opacity as determined by EPA Method 9.

<u>Cooling Tower</u>: BACT for emissions of PM/PM10 from the cooling tower is a design drift rate of no more than 0.001 percent of the circulating water flow rate.

Gas Turbines/HRSG Systems

Pollutant	Fuel	Method of Operation	Initial		CEMS
			ppmvd @ 15% O2	lb/hour	ppmvd @ 15% O2
CO [a]	Oil	Simple or Combined Cycle	14.4, 3-hr	64.7	15.0, 24-hr
	Gas	Simple or Combined Cycle	7.4, 3-hr	27.5	8.0, 24-hr
		Combined Cycle w/DB	7.4, 3-hr	37.5	8.0, 24-hr
		Simple or Combined Cycle w/PA	12.0, 3-hr	45.0	12.0, 24-hr
		Combined Cycle w/DB+PA	12.0, 3-hr	55.6	12.0, 24-hr
NOx [b]	Oil	Simple Cycle	42.0, 3-hr	319.2	42.0, 3-hr
		Combined Cycle – SCR	10.0, 3-hr	76.0	10.0, 24-hr
	Gas	Simple Cycle	9.0, 3-hr	58.7	9.0, 24-hr
		Simple Cycle w/PA	NA	(76.2)	12.0, 1-hr
		Simple Cycle w/Peaking	NA	(101.3)	15.0, 1-hr
		Combined Cycle – SCR	2.5, 3-hr	16.3	2.5, 24-hr
		Combined Cycle w/DB – SCR	2.5, 3-hr	22.1	2.5, 24-hr
PM/PM10 [c]	Oil/Gas	Simple or Combined Cycle	Fuel Specifications		
		Simple or Combined Cycle	Visible emissions shall not exceed 10% opacity for each 6-minute average as determined by EPA Method 9 observations.		
SAM/SO2 [d]	Oil/Gas	Simple or Combined Cycle	Fuel Specifications		
VOC [e]	Oil	Simple or Combined Cycle	2.5, 3-hr	6.0	NA
	Gas	Simple or Combined Cycle	1.3, 3-hr	2.8	NA
		Combined Cycle, w/DB or PA	4.0, 3-hr	9.2	NA
Ammonia [f]	Oil/Gas	Combined Cycle – SCR	5.0, 3-hr	NA	NA

FINAL BACT DETERMINATIONS

As summarized above, the Department determines that the standards specified in this permit represent the Best Available Control Technology (BACT) for emissions of CO, NOx, PM, SAM, SO_2, and VOC. The Department's technical review and rationale for the BACT determinations are presented in Technical Evaluation and Preliminary Determination issued concurrently with the draft permit.

Determination By:
(DRAFT)

J. F. Koerner, P.E., Project Engineer
New Source Review Section

Recommended By:
(DRAFT)

C. H. Fancy, Chief
Bureau of Air Regulation

Approved By:
(DRAFT)

Howard L. Rhodes, Director
Division of Air Resources Management

NSPS SUBPART Da REQUIREMENTS FOR DUCT BURNERS

The duct burners in the heat recovery steam generators (HRSGs) are subject to the applicable requirements of Subpart A (General Provisions) and Subpart Da (Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978) established as New Source Performance Standards in 40 CFR 60 and adopted by reference in Rule 62-204.800(7)(b), F.A.C. The specific federal requirements are not listed, but can be obtained from the Department upon request.

NSPS GENERAL PROVISIONS

The emissions units are subject to the applicable General Provisions of the New Source Performance Standards including 40 CFR 60.7 (Notification and Record Keeping), 40 CFR 60.8 (Performance Tests), 40 CFR 60.11 (Compliance with Standards and Maintenance Requirements), 40 CFR 60.12 (Circumvention), 40 CFR 60.13 (Monitoring Requirements), and 40 CFR 60.19 (General Notification and Reporting Requirements).

NSPS SUBPART Da REQUIREMENTS

The duct burners in the heat recovery steam generators (HRSGs) shall comply with the following federal requirements of 40 CFR 60, Subpart Da.

§ 60.40a Applicability and designation of affected facility.
§ 60.41a Definitions.
§ 60.42a Standard for particulate matter.
§ 60.43a Standard for sulfur dioxide.
§ 60.44a Standard for nitrogen oxides.
§ 60.46a Compliance provisions.
§ 60.47a Emission monitoring.
§ 60.48a Compliance determination procedures and methods.
§ 60.49a Reporting requirements.

Permitting Notes:

- *The duct burners have a heat input greater than 250 MMBtu per hour and are subject to NSPS Subpart Da.*
- *Particulate matter emissions are limited to 0.03 lb/million Btu heat input derived from the combustion of gaseous fuel. The exclusive firing of natural gas is expected to result in particulate matter emissions of less than 0.008 lb/MMBtu.*
- *Sulfur dioxide emissions are limited to 0.20 lb/million Btu heat input based on 100 percent of the potential combustion concentration (zero percent reduction). The exclusive firing of natural gas is expected to result in sulfur dioxide emissions of less than 0.005 lb/MMBtu.*
- *Nitrogen oxide emissions are limited to 1.6 pounds per megawatt-hour (gross energy output) as provided under § 60.46a(k)(1). Compliance with the emissions limit is determined by the three-run average (nominal 1-hour runs) for the initial and subsequent performance tests. The combined gas turbine and duct burner emissions readily comply with this standard.*

NSPS SUBPART Dc REQUIREMENTS FOR GAS-FIRED FUEL HEATERS

The following emissions units are subject to the applicable requirements of Subpart A (General Provisions) and Subpart Dc (Small Industrial-Commercial-Institutional Steam Generating Units) established as New Source Performance Standards in 40 CFR 60 and adopted by reference in Rule 62-204.800(7)(b), F.A.C. The specific federal requirements are not listed, but can be obtained from the Department upon request.

ID	Emission Unit Description
013	Four gas-fired fuel heaters

NSPS GENERAL PROVISIONS

The emissions units are subject to the applicable General Provisions of the New Source Performance Standards including 40 CFR 60.7 (Notification and Record Keeping), 40 CFR 60.8 (Performance Tests), 40 CFR 60.11 (Compliance with Standards and Maintenance Requirements), 40 CFR 60.12 (Circumvention), 40 CFR 60.13 (Monitoring Requirements), and 40 CFR 60.19 (General Notification and Reporting Requirements).

NSPS SUBPART Dc REQUIREMENTS

The gas-fired fuel heaters shall comply with the following federal requirements of 40 CFR 60, Subpart Dc.

§ 60.40c Applicability and delegation of authority.
§ 60.41c Definitions.
§ 60.42c Standard for sulfur dioxide.
§ 60.43c Standard for particulate matter.
§ 60.44c Compliance and performance test methods and procedures for sulfur dioxide.
§ 60.45c Compliance and performance test methods and procedures for particulate matter.
§ 60.46c Emission monitoring for sulfur dioxide
§ 60.47c Emission monitoring for particulate matter.
§ 60.48c Reporting and record keeping requirements.

Permitting Notes:

- *NSPS Subpart Dc defines steam generating unit to mean, "... a device that combusts any fuel and produces steam or heats water or any other heat transfer medium." Because the fuel heaters have a heat input of 22 MMBtu per hour each and heat natural gas prior to combustion in the gas turbines, the units are subject to NSPS Subpart Dc.*
- *Because the fuel heaters fire only natural gas, these units are subject only to notification, record keeping, and reporting requirements. The Department believes that the specific conditions of the permit are sufficient to demonstrate compliance with NSPS Subpart Dc.*

GENERAL CONDITIONS

The permittee shall comply with the following general conditions from Rule 62-4.160, F.A.C.

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.

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, exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.

3. As provided in Subsections 403.087(6) and 403.722(5), Florida Statutes, the issuance of this permit does not convey and 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.

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.

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.

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.

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.

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.

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.

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.

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.

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

13. This permit also constitutes:

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

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.

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.

NSPS SUBPART GG REQUIREMENTS FOR GAS TURBINES

The following emissions units are subject to the applicable requirements of Subpart A (General Provisions) and Subpart GG (Stationary Gas Turbines) established as New Source Performance Standards in 40 CFR 60 and adopted by reference in Rule 62-204.800(7)(b), F.A.C. The specific federal requirements are not listed, but can be obtained from the Department upon request.

ID	Emission Unit Description
011	Unit 8A Gas Turbine (170 MW) with Heat Recovery Steam Generator
012	Unit 8B Gas Turbine (170 MW) with Heat Recovery Steam Generator
017	Unit 8C Gas Turbine (170 MW) with Heat Recovery Steam Generator
018	Unit 8D Gas Turbine (170 MW) with Heat Recovery Steam Generator

NSPS GENERAL PROVISIONS

The emissions units are subject to the applicable General Provisions of the New Source Performance Standards including 40 CFR 60.7 (Notification and Record Keeping), 40 CFR 60.8 (Performance Tests), 40 CFR 60.11 (Compliance with Standards and Maintenance Requirements), 40 CFR 60.12 (Circumvention), 40 CFR 60.13 (Monitoring Requirements), and 40 CFR 60.19 (General Notification and Reporting Requirements).

NSPS SUBPART GG REQUIREMENTS

The gas turbines shall comply with the following federal requirements.

§ 60.330 Applicability and designation of affected facility.
§ 60.331 Definitions.
§ 60.332 Standard for Nitrogen Oxides.
§ 60.333 Standard for Sulfur Dioxide.
§ 60.334 Monitoring of Operations.
§ 60.335 Test Methods and Procedures.

Permitting Notes:

- *Based on the manufacturer's data and compressor inlet conditions of 59° F and 60% relative humidity, the heat rate for gas firing is 9250 Btu/KW-h at peak load and for oil firing is 9960 Btu/KW-h at peak load. This results in "Y" values of 9.8 for gas firing and 10.5 for oil firing. The equivalent NSPS NOx emission standards are 110/103 ppmvd at 15% oxygen for gas/oil firing. The emissions standards of the PSD permit are more stringent than this requirement. When firing natural gas, the "F" value (NOx allowance for fuel bound nitrogen shall be assumed to be 0. See EPA's March 12, 1993 determination regarding the use of NOx CEMS.*
- *The gas turbine is limited to firing any fuel that contains sulfur in excess of 0.8 percent by weight.*
- *The requirement to monitor the nitrogen content of natural gas fired is waived. A NOx CEMS shall be used to demonstrate compliance with the NOx limits of this permit. This is consistent with the custom fuel monitoring policy and guidance from EPA Region 4.*
- *The permit contains a custom monitoring schedule for determining the sulfur content of fuels that is sufficient to demonstrate compliance with the NSPS limit. It is consistent with the custom fuel monitoring policy and guidance from EPA Region 4.*
- *Emissions in excess of the NSPS standard for nitrogen oxides shall be determined on 1-hour basis. The continuous compliance demonstration by NOx CEM system data shall substitute for the NSPS requirements regarding the water-to-fuel ration. NOx CEM system data shall be used to determine "excess emissions" for purposes of 40 CFR 60.7 subject to the conditions of the permit. As required by EPA's March 12, 1993 determination, the NOx monitor shall meet the applicable requirements of 40 CFR 60.13, Appendix B and Appendix F for certifying, maintaining, operating and assuring the quality of the system; shall be capable of calculating NOx emissions concentrations corrected to 15% oxygen; shall have no less than 95% monitor availability in any given calendar quarter; and shall provide a minimum*

of four data points for each hour and calculate an hourly average. The requirements for the CEM systems specified by the specific conditions of this permit satisfy these requirements.}

- *Emissions in excess of the NSPS standard for sulfur dioxide shall be determined on a daily basis. However, the frequency specified in the custom fuel monitoring schedule is sufficient to demonstrate compliance with the with the NSPS limit. It is consistent with the custom fuel monitoring policy and guidance from EPA Region 4.*
- *The permittee is required to submit a semiannual report of emission in excess of the NSPS standards as required by 40 CFR 60.7, Subpart A, General Provisions.*
- *The Department may request that NOx emission data also be presented in terms of the NSPS standard (NOx at 15 percent O_2 and ISO standard ambient conditions, volume percent). The permittee is not required to have the NOx monitor continuously correct NOx emissions concentrations to ISO conditions. However, the permittee shall keep records of the data needed to make the correction, and shall make the correction when required by the Department or Administrator. This is consistent with guidance from EPA Region 4.*
- *The permittee is allowed to conduct initial performance tests at a single load because the permit requires demonstration of continuous compliance with the NOx BACT standards. This is consistent with guidance from EPA Region 4.*
- *The permittee is allowed to make the initial compliance demonstration for NOx emissions using certified CEM system data, provided that compliance is based on a minimum of three test runs representing a total of at least three hours of data, and that the CEMS be calibrated in accordance with the procedure in section 6.2.3 of Method 20 following each run. Alternatively, initial compliance may be demonstrated using data collected during the initial relative accuracy test audit (RATA) performed on the NOx monitor. The span value specified in the permit shall be used instead of that specified in the NSPS requirements. Flow rate data shall be obtained to calculate mass emission rates. These initial compliance demonstration requirements are consistent with guidance from EPA Region 4. The span value is changed pursuant to Department authority and is consistent with guidance from EPA Region 4.*
- *The permit species sulfur testing methods and allows the permittee to follow the requirements of 40 CFR 75 Appendix D to determine the sulfur content. These requirements allow different methods than provided by the NSPS requirements, but are equally stringent and will ensure compliance with this rule.*
- *The fuel analysis requirements of the permit meet or exceed the NSPS requirements and ensure compliance.*

STANDARD CONDITIONS

Unless otherwise specified in the permit, the following conditions apply to all emissions units and activities at this facility.

EMISSIONS AND CONTROLS

1. 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 permittee shall notify each Compliance Authority as soon as possible, but at least within one working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; 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 or the regulations. [Rule 62-4.130, F.A.C.]

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

3. Excess Emissions Allowed: Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration. [Rule 62-210.700(1), F.A.C.]

4. Excess Emissions Prohibited: 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. [Rule 62-210.700(4), F.A.C.]

5. Excess Emissions - Notification: In case of excess emissions resulting from malfunctions, the permitee shall notify the Department or the appropriate Local Program in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department. [Rule 62-210.700(6), F.A.C.]

6. VOC or OS Emissions: No person shall store, pump, handle, process, load, unload or use in any process or installation, volatile organic compounds or organic solvents without applying known and existing vapor emission control devices or systems deemed necessary and ordered by the Department. [Rule 62-296.320(1), F.A.C.]

7. Objectionable Odor Prohibited: No person shall cause, suffer, allow or permit the discharge of air pollutants, which cause or contribute to an objectionable odor. An "objectionable odor" means any odor present in the outdoor atmosphere which by itself or in combination with other odors, is or may be harmful or injurious to human health or welfare, which unreasonably interferes with the comfortable use and enjoyment of life or property, or which creates a nuisance. [Rules 62-296.320(2) and62-210.200(203), F.A.C.]

8. General Visible Emissions: No person shall cause, let, permit, suffer or allow to be discharged into the atmosphere the emissions of air pollutants from any activity equal to or greater than 20 percent opacity. [Rule 62-296.320(4)(b)1, F.A.C.]

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.]

TESTING REQUIREMENTS

10. Required Number of Test Runs: For mass emission limitations, a compliance test shall consist of three complete and separate determinations of the total air pollutant emission rate through the test section of the stack or duct and three complete and separate determinations of any applicable process variables corresponding to the three distinct time periods during which the stack emission rate was measured; provided, however, that three complete and separate determinations shall not be required if the process variables are not subject to variation during a compliance test, or if three determinations are not necessary in order to calculate the unit's emission rate. The three required test runs shall be completed within one consecutive five-day period. In the event that a sample is lost or one of the three runs must be discontinued because of circumstances beyond the control of the owner or operator, and a valid third run cannot be obtained within the five-day period allowed for the test, the Secretary or his or her designee may accept the results of two complete runs as proof of compliance, provided that the arithmetic mean of the two complete runs is at least 20% below the allowable emission limiting standard. [Rule 62-297.310(1), F.A.C.]

11. Operating Rate During Testing: Testing of emissions shall be conducted with the emissions unit operating at permitted capacity. Permitted capacity is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. If it is impractical to test at permitted capacity, an emissions unit may be tested at less than the maximum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test rate 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 purpose of additional compliance testing to regain the authority to operate at the permitted capacity. [Rule 62-297.310(2), F.A.C.]

12. Calculation of Emission Rate: For each emissions performance test, the indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the three separate test runs unless otherwise specified in a particular test method or applicable rule. [Rule 62-297.310(3), F.A.C.]

13. Test Procedures: Tests shall be conducted in accordance with all applicable requirements of Chapter 62-297, F.A.C.

    a. Required Sampling Time. Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes. The minimum observation period for a visible emissions compliance test shall be thirty (30) minutes. The observation period shall include the period during which the highest opacity can reasonably be expected to occur.

    b. Minimum Sample Volume. Unless otherwise specified in the applicable rule or test method, the minimum sample volume per run shall be 25 dry standard cubic feet.

    c. Calibration of Sampling Equipment. Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1, F.A.C.

    [Rule 62-297.310(4), F.A.C.]

14. Determination of Process Variables

    a. Required Equipment. The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.

    b. Accuracy of Equipment. Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight 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.]

15. Sampling Facilities: The permittee shall install permanent stack sampling ports and provide sampling facilities that meet the requirements of Rule 62-297.310(6), F.A.C.

16. Test Notification: The owner or operator shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator. [Rule 62-297.310(7)(a)9, F.A.C.]

17. Special Compliance Tests: When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it shall require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department. [Rule 62-297.310(7)(b), F.A.C.]

18. Test Reports: The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department on the results of each such test. The required test report shall be filed with the Department as soon as practical but no later than 45 days after the last sampling run of each test is completed. The test report shall provide

sufficient detail on the emissions unit tested and the test procedures used to allow the Department to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information:

1) The type, location, and designation of the emissions unit tested.
2) The facility at which the emissions unit is located.
3) The owner or operator of the emissions unit.
4) The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.
5) The means, raw data and computations used to determine the amount of fuels used and materials processed, if necessary to determine compliance with an applicable emission limiting standard.
6) The type of air pollution control devices installed on the emissions unit, their general condition, their normal operating parameters (pressure drops, total operating current and GPM scrubber water), and their operating parameters during each test run.
7) A sketch of the duct within 8 stack diameters upstream and 2 stack diameters downstream of the sampling ports, including the distance to any upstream and downstream bends or other flow disturbances.
8) The date, starting time and duration of each sampling run.
9) The test procedures used, including any alternative procedures authorized pursuant to Rule 62-297.620, F.A.C. Where optional procedures are authorized in this chapter, indicate which option was used.
10) The number of points sampled and configuration and location of the sampling plane.
11) For each sampling point for each run, the dry gas meter reading, velocity head, pressure drop across the stack, temperatures, average meter temperatures and sample time per point.
12) The type, manufacturer and configuration of the sampling equipment used.
13) Data related to the required calibration of the test equipment.
14) Data on the identification, processing and weights of all filters used.
15) Data on the types and amounts of any chemical solutions used.
16) Data on the amount of pollutant collected from each sampling probe, the filters, and the impingers, are reported separately for the compliance test.
17) The names of individuals who furnished the process variable data, conducted the test, analyzed the samples and prepared the report.
18) All measured and calculated data required to be determined by each applicable test procedure for each run.
19) The detailed calculations for one run that relate the collected data to the calculated emission rate.
20) The applicable emission standard, and the resulting maximum allowable emission rate for the emissions unit, plus the test result in the same form and unit of measure.
21) A certification that, to the knowledge of the owner or his authorized agent, all data submitted are true and correct. When a compliance test is conducted for the Department or its agent, the person who conducts the test shall provide the certification with respect to the test procedures used. The owner or his authorized agent shall certify that all data required and provided to the person conducting the test are true and correct to his knowledge.

RECORDS AND REPORTS

19. Records Retention: All measurements, records, and other data required by this permit shall be documented in a permanent, legible format and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. Records shall be made available to the Department upon request. [Rules 62-4.160(14) and 62-213.440(1)(b)2, F.A.C.]

20. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating rates and emissions from this facility. Annual operating reports shall be submitted to the Compliance Authority by March 1st of each year. [Rule 62-210.370(2), F.A.C.]

P.E. CERTIFICATION STATEMENT

PERMITTEE

Florida Power and Light Company
P.O. Box 176
Indiantown, FL 34956

FPL Martin Power Plant Project No. 0850001-010-AC Air Permit No. PSD-FL-327

PROJECT DESCRIPTION

The applicant proposes to construct a "4-on-1" 1150 MW combined cycle Unit 8 consisting of the following equipment and specifications: two existing 170 MW simple cycle gas turbine-electrical generator sets (8A and 8B), two new 170 MW gas turbine-electrical generator sets (8C and 8D), four gas-fired heat recovery steam generators (495 MMBtu/hour, LHV), a common steam-electrical generator (470 MW), two new gas-fired fuel heaters (22 MMBtu/hour, each), a cooling tower, and other associated support equipment. Each gas turbine will fire natural gas as the primary fuel and very low sulfur distillate oil as a restricted alternate fuel (≤ 500 hours/year). Each gas turbine may operate in simple cycle mode for 3390 hours per year while the combined cycle components are being constructed. Once combined cycle operation is established, simple cycle operation is limited to an average of 1000 hours per year. Additional equipment includes four 120-foot stacks combined cycle stacks, four 80-foot simple cycle stacks, and an aqueous ammonia storage tank.

CO, PM/PM_{10}, and VOC will be minimized by the efficient, high-temperature combustion of natural gas and distillate oil. Emissions of SAM and SO_2 will be minimized by firing natural gas and restricting the amounts of very low sulfur distillate oil. NOx emissions will be reduced with dry low-NOx (DLN) combustion technology for gas firing and water injection for oil firing. In combination with these NOx controls, a selective catalytic reduction (SCR) system further reduces NOx emissions during combined cycle operation. These controls are determined to represent the Best Available Control Technology (BACT). The following limited alternate methods of operation are allowed: duct burning (DB, 2880 hours per year), power augmentation (PA, 400 hours/year), and peaking (60 hour/year for simple cycle and 400 hours/year for combined cycle). The draft permit includes the following standards for emissions of CO, NOx, VOC, and ammonia.

Pollutant	Fuel	Method of Operation	ppmvd @ 15% O_2	Compliance
CO	Oil	Simple or Combined Cycle	15.0, 24-hr	CEMS
	Gas	Simple or Combined Cycle	8.0, 24-hr	CEMS
		Simple or Combined Cycle w/PA	12.0, 24-hr	CEMS
NOx	Oil	Simple Cycle	42.0, 3-hr	CEMS
		Combined Cycle – SCR	10.0, 24-hr	CEMS
	Gas	Simple Cycle	9.0, 24-hr	CEMS
		Simple Cycle w/PA	12.0, 1-hr	CEMS
		Simple Cycle w/Peaking	15.0, 1-hr	CEMS
		Combined Cycle – SCR	2.5, 24-hr	CEMS
VOC	Oil	Simple or Combined Cycle	2.5, 3-hr	Test
	Gas	Simple or Combined Cycle	1.3, 3-hr	Test
		Combined Cycle	4.0, 3-hr	Test
Ammonia	Oil/Gas	Combined Cycle	5.0, 3-hr	Test

I HEREBY CERTIFY *that the air pollution control engineering features described in the above referenced application and subject to the proposed permit conditions provide reasonable assurance of compliance with applicable provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Chapters 62-4 and 62-204 through 62-297. However, I have not evaluated and I do not certify aspects of the proposal outside of my area of expertise (including but not limited to the electrical, mechanical, structural, hydrological, meteorological, and geological features).*

Jeffery J. Koerner
7-30-02

Jeffery F. Koerner, P.E.
Registration Number: 49441
(Date)

Memorandum Florida Department of Environmental Protection

TO:	Clair Fancy, Chief, BAR
THROUGH:	Al Linero, Administrator - New Source Review Section
FROM:	Jeff Koerner, New Source Review Section JK
DATE:	July 30, 2002
SUBJECT:	FPL Martin Power Plant Project No. 0850001-010-AC PSD Permit No. 327 Unit 8 - New 1150 MW "4-on-1" Combined Cycle Gas Turbine

Attached for your review are the following items:

- Intent to Issue Permit and Public Notice Package;
- Technical Evaluation and Preliminary Determination;
- Draft Permit; and
- PE Certification.

The Technical Evaluation and Preliminary Determination provides a detailed description of the project, rule applicability, BACT determinations and permit conditions. The P.E. certification briefly summarizes the proposed project. The project is subject to power plant siting. Day #90 is August 4, 2002. I recommend your approval of the attached Draft Permit for this project.

CHF/AAL/jfk

Attachments

Golder Associates Inc.
6241 NW 23rd Street, Suite 500
Gainesville, FL 32653-1500
Telephone (352) 336-5600
Fax (352) 336-6603

Golder Associates

May 3, 2002

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BUREAU OF AIR REGULATION

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Mr. Jeffery F. Koerner, P.E.
New Source Review Section
Bureau of Air regulation
Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399

RE: FPL MARTIN EXPANSION PROJECT
Request for Additional Information
Project No. 085001-010-AC (PSD-FL-327)

Dear Jeff:

On behalf of Mr. John Lindsay of Florida Power & Light Company, I am submitting the enclosed responses to the comments and questions contained in your March 1, 2002 letter to Mr. Lindsay concerning the Air Permit and Prevention of Significant Deterioration (PSD) Application for the FPL Martin Expansion Project. The responses to your comments and questions have also been included in the sufficiency responses submitted to Mr. Over as part of the Site Certification proceedings.

Also included with these response is the initial compliance test results for Martin Units 8A and 8B when firing distillate oil. These tests were submitted previously to demonstrate compliance with emission limits.

We trust this responds fully to all of your comments and questions. Please contact either Mr. Simmons, the FPL application contact [phone (561) 691-2216], or myself if we may be of further assistance.

Sincerely,

GOLDER ASSOCIATES INC.

Kennard F. Kosky

Kennard F. Kosky, P.E.
Principal

KENNARD F. KOSKY PROFESSIONAL ENGINEER NO. 14996 STATE OF FLORIDA

KFK/lsh

Enclosures: 1 copy

cc: John M. Lindsay, Plant General Manager Martin Plant
K. H Simmons, Manager of New Capacity Projects

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Martin Expansion Project
Additional Information – FDEP New Source Review Section
Project No. 085001-010-AC (PSD-FL-327)

Comment 1a: "Equipment Description: Please verify and comment on the information in the following description of equipment: Combined Cycle Unit No. 8 will be a "4 on 1" unit consisting of four 170 MW gas turbines, four gas-fired heat recovery steam generators (HRSGs), and one steam turbine-electrical generator."

Response: Yes the statement is correct. The project will include a "4 on 1" unit consisting of four General Electric (GE) nominal 170 MW gas turbines, four heat recovery steam generators (HRSGs) with duct firing, one steam turbine-electrical generator and associated ancillary equipment. Two of the combustion turbines are existing simple cycle units. The project also includes the option of a mechanical draft cooling tower.

Comment 1b: "Gas Turbines: Each gas turbine (Unit Nos. 8A, 8B, 8C, and 8D) includes General Electric Model PG7241(FA) combustion turbine-electrical generator set, an automated gas turbine control system, an inlet air filtration system, an evaporative inlet air cooling system, a simple cycle exhaust stack that is 80 feet tall and 22.0 feet in diameter, fuel distribution systems, and ancillary support equipment. Exhaust gases will exit the simple cycle stack at approximately 1116°F with a volumetric flow rate of approximately 2,389,500 acfm."

Response: Yes, the statement is correct. Each gas turbine (Unit Nos. 8A, 8B, 8C, and 8D) includes a General Electric Model PG7241 (FA) combustion turbine-electrical generator set, an automated gas turbine control system, an inlet air filtration system, an evaporative inlet air cooling system, a simple cycle exhaust stack (that has been modeled at 80 feet tall and 22.0 feet in diameter), fuel distribution systems, and ancillary support equipment. Exhaust gases will exit the simple cycle stack at approximately 1116°F with a volumetric flow rate of approximately 2,389,500 acfm, based on an ambient (turbine inlet) temperature of 59° F.

Comment 1c: "Heat Recovery Steam Generators (HRSGs): During combined cycle operation, the exhaust from each gas turbine will pass through a separate gas-fired heat recovery steam generator with an exhaust stack that is 120 feet tall and 19.0 feet in diameter. Exhaust gases will exit the HRSG stack at approximately 202°F with a volumetric flow rate of approximately 1,004,000 acfm."

Response: Yes, the statement is correct. During combined cycle operation, the exhaust from each gas turbine will pass through a separate gas-fired heat recovery steam generator with an exhaust stack that is 120 feet tall and 19.0 feet in diameter. Exhaust gases will exit the HRSG stack at approximately 202°F with a volumetric flow rate of approximately 1,004,000 acfm, based on an ambient (turbine inlet) temperature of 59°F.

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Comment 1d: "Fuels and Firing Rates: The primary fuel for each gas turbine is natural gas with very low sulfur distillate oil (0.05 percent sulfur by weight) serving as a backup fuel on a restricted basis. At a compressor inlet air temperature of 59°F, the maximum heat input rate of each gas turbine is 1600 MMBtu (LHV) per hour when firing natural gas and 1811 MMBtu (LHV) per hour when firing distillate oil. Each HRSG is designed with duct burners having a maximum heat input of 550 MMBtu (LHV) per hour when firing natural gas."

Response: The statement is correct except that the each HRSG is designed with duct burners having a maximum heat input of 550 MMBtu per hour based on the higher heating value (HHV) and 495 MMBtu per hour based on the lower heating value (LHV). In addition, distillate oil is considered an "alternate" fuel that may be used on a restricted basis.

Comment 1e: "Generating Capacity: At a compressor inlet air temperature of 59°F and the maximum heat input rate, each gas turbine generates a nominal 172 MW of shaft-driven electricity when firing natural gas and 180 MW of shaft-driven electricity when firing distillate oil. The single steam-turbine electrical generator is rated at a capacity of 470 MW. With all four gas turbines in operation and firing all HRSG duct burners, the combined cycle system generates a nominal 1150 MW of electricity."

Response: Yes, the statement is correct. At a compressor inlet air temperature of 59°F and the maximum heat input rate, each gas turbine generates a nominal 172 MW of shaft-driven electricity when firing natural gas and nominal 180 MW of shaft-driven electricity when firing distillate oil. The single steam-turbine electrical generator is rated at a nominal capacity of 470 MW. With all four gas turbines in operation and firing all HRSG duct burners, the combined cycle system generates a nominal 1150 MW of electricity.

Comment 1f: "Controls: Each gas turbine incorporates General Electric's dry low-NO_x combustion system (2.6) to minimize the formation of NO_x emissions when firing natural gas. A water injection system will be installed to minimize NO_x emissions when firing distillate oil. A conventional selective catalytic reduction (SCR) system will be installed in the HRSG to further reduce NO_x emissions during combined cycle operation. The efficient combustion of very low sulfur fuels at high temperatures minimizes the emissions of CO, PM/PM_{10}, SO_2 and VOC."

Response: Yes, the statement is correct. Each gas turbine incorporates General Electric's dry low-NO_x combustion system (2.6) to minimize the formation of NO_x emissions when firing natural gas. A water injection system will be installed to minimize NO_x emissions when firing distillate oil. A conventional selective catalytic reduction (SCR) system will be installed in the HRSG to further reduce NO_x emissions during combined cycle operation. The efficient combustion of very low sulfur fuels at high temperatures minimizes the emissions of CO, PM/PM_{10}, SO_2 and VOC.

Comment 1g: "Continuous Monitors: Each gas turbine will be equipped with continuous emissions monitoring systems (CEMS) to measure and record NO_x emissions as well as flue gas carbon dioxide content."

Response: Yes, the statement is correct except either carbon dioxide or oxygen, as the diluent gas for nitrogen oxides will be selected. Each gas turbine will be equipped with continuous emissions monitoring systems (CEMS) to measure and record NO_x emissions.

Comment 2: "Fuel Heaters: Please describe when fuel heating is necessary. Why will the gas-fired fuel heaters operate more during the first year of operation? Why aren't the fuel heaters necessary during combined cycle operation? Is there a separate heat transfer system used during combined cycle operation?"

Response: The GE 7FA combustion turbine is available with two types of DLN combustors that fire natural gas. The first type is called a "cold" nozzle and the second type is a "hot" nozzle. FPL uses the hot nozzle design because it uses hot fuel (290-365°F), which is heated using waste energy from the combustion turbine exhaust via a feed water heat exchanger. This improves the overall plant efficiency. The hot nozzles require a temperature of the natural gas to be 290°F when at a minimum continuous load of (30 MW). The energy to heat the fuel from a feed water heater is not available in simple cycle mode since there is no steam cycle and is not available during initial start up. The energy to heat the natural gas during these conditions must be supplied from another source, which is a direct fired gas heater. The direct fired gas heaters are used in simple cycle mode and may be used during the first 30 to 60 minutes of startup in combined cycle mode. In full combined cycle mode the fuel heaters are not required since waste heat from a feed water heater is used. For the first year of operation in simple cycle mode and during the plant start up phases, there will be times when the fuel gas heaters will be required to operate.

Comment 3: "Cooling Tower: Please identify the determining factors in whether or not the proposed cooling tower will be installed."

Response: The primary determining factor in whether or not the proposed cooling tower will be installed are construction considerations. With regards to construction, FPL is further investigating various construction techniques in order to minimize the costs associated with the installation of intake and outfall structures, including circulating water pipe sized to accommodate a once through cooling system. One alternative being the construction of a cooling tower which would be capable of using the existing Units 3 and 4 Intake and Outfall structures and associated circulating water piping.

Comment 4: "Fuel Oil Tanks: The application indicates that the combined capacity of both fuel tanks will be approximately 2 million gallons. Based on the maximum firing rate of 14,000 gallons per hour per gas turbine, the tanks would only provide about 36 hours of simultaneous operation of all four units. Approximately how many truckloads of oil will it take to fill the two tanks? Approximately how long will it take to empty one truckload of oil? How long will it take to refill the tanks? Are there adequate roadways to provide access for this number of trucks? Describe how oil would be delivered and transferred to the tanks when the units were in operation and were expected to fire oil for an extended period of time, such as several days."

Response: Chapter 3, page 3-5 of the application describes the light oil storage facilities of the project, "light oil will be stored in the existing 2-million-gallon tank and in a 2-million-gallon tank authorized in the 1991 certification for Units 3 and 4 but not constructed." The total combined capacity of both fuel tanks will be approximately 4 million gallons. The existing 2-million gallon tank is currently being used for Units 8A and 8B. Based on the maximum firing rate of 13,900 gallons per hour per CT, the tanks would provide about 72 hours of simultaneous operation in the event all four units were fired at full load. Each 2-million-gallon tank will require about 270 truckloads at a nominal capacity of 7,500 gallons per standard tanker truck. At 13,900 gallons per hour it will take each CT about 32 minutes to burn the amount of distillate oil in a standard tanker. The facility has the ability to off-load two standard oil tankers at a time and a rate of 50,400 gallons per hour. Since oil will not be the primary fuel, the filling of each tank will be scheduled over a period of time. A traffic analysis was performed for both construction and operation and was presented in Chapters 4 and 5 of the Site Certification Application. The most traffic occurs during construction when several hundred construction workers will come to and exit the site. The traffic analysis determined under worst case construction traffic that the roads would operate at an acceptable level of service (Section 4.6.1 of SCA).

Comment 5a: "Operational Restrictions Requested: Please comment on the Department's interpretation of the following restrictions requested in the application.

Each gas turbine shall fire no more than 500 hours of oil per consecutive 12 months (or equivalent oil consumption at full load).

- Because of higher emissions of nearly all pollutants when firing oil, the Department has restricted oil firing as part of its BACT determination for several recent projects. For similar projects, the Department has restricted oil firing to no more than 250 hours per year per gas turbine at full load. Please comment.
- The Department will consider this restricted operation in terms of hours of operation or fuel consumption (gallons). Please identify the preferred restriction in these terms."

Response: FPL has requested a fuel equivalent of 500 hours of light oil operation per consecutive 12 months per CT. The amount of light oil firing requested in the application is a project specific requirement. The existing Unit 8A and 8B CTs are currently permitted a fuel equivalent of 500 hours/CT/year [i.e., 7,358,350 gallons; see PSD-FL-286, Section III, Condition 8(6)]. FPL's operational requirements dictate that the new Unit 8 CT oil firing limitations match that of the existing CTs.

While it is acknowledged that the Department recently permitted projects with 250 hours of light oil firing, FDEP has also proposed permits for recent projects with 500 hours of light oil operation per consecutive 12 months per CT, e.g., South Pond Energy Park, LLC (draft permit dated in November, 2001). South Pond Energy Park, LLC is a 600 MW electrical generating plant in Hardee County, FL, consisting three GE 7FA units. In addition, unlike independent power projects that the Department has recently permitted, FPL has a statutory obligation to supply electric power at all times. Having the ability to use light distillate oil for an equivalent of 500 hours per CT provides the reliability to meet this obligation.

The preferred restriction for limiting light oil firing operation is in terms of fuel consumption (gallons): "The maximum annual usage for the four CTs is 29,433,400 gallons." Calculation: 7,358,350 gallons/CT x 4 CTs = 29,433,400 gallons.

Comment 5b: "Duct firing shall not exceed an equivalent of 2880 hours per year per HRSG at full capacity.

Please identify the requested restriction in terms of maximum hours of operation or gas consumption (million cubic feet of gas)."

Response: The preferred restriction for limiting duct firing is in terms of gas consumption. Based on 2880 hr/yr/HRSG and 550 MMBtu/hr/HRSG, the maximum fuel consumption is calculated to be 274 million lb/year or 6 billion scf/year for all four HRSGs.

Comment 5c: "Each gas turbine shall be limited to no more than 400 hours per consecutive 12 months of steam injection for power augmentation."

Response: Yes, the statement is correct. The application requests that each gas turbine be limited to no more than 400 hours per consecutive 12 months of steam injection for power augmentation. This restriction is the same as the current permit limitation of the existing Units 8A and 8B CTs.

Comment 5d: "Each gas turbine shall be limited to no more than 60 hours per consecutive 12 months of high temperature peaking operation."

Response: Yes, the statement is correct for simple cycle operation. The application request that each gas turbine be limited to no more than 60 hours per consecutive 12 months of high temperature peaking operation. This restriction is the same as the current permit limitation of the existing Unit 8 CTs. For combined cycle operation, the peak mode, which was characterized as the "Higher Power Mode" and included steam augmentation, a 400 hours per consecutive 12 month is requested.

Comment 5e: "Excluding startup and shutdown, each gas turbine shall not operate below 50 percent of base load."

Response: FPL requests that operation not be limited by load, but rather compliance with emission limits. During the construction of combined cycle, operating the CTs at less than 50 percent load will be required for extended periods to accomplish steam blows. A permit condition to accomplish this was included in the application (refer to Section 2.0). In addition, some maintenance conditions and operational circumstances may require operation at less than 50 percent load.

Comment 5f: "Until capable of operating in combined cycle mode, each gas turbine shall operate no more than 3390 hours per consecutive 12 months."

Response: Yes, until capable of operating in combined cycle mode, each gas turbine shall operate no more than a fuel equivalent of 3,390 hours per consecutive 12 months or 5,902,588,000 SCF of gas per turbine. The existing Units 8A and 8B CTs are limited on this basis [see PSD-FL-286, Section III, Condition 8(a)]. If oil is used, the natural gas limit would be reduced by 127.4 SCF of gas for every gallon of distillate oil used.

Comment 5g: "Once combined cycle operation is established, simple cycle operation of the four gas turbines shall not exceed an average of 1000 hours per consecutive 12 months. Operation of any simple cycle operation shall not exceed 3390 hours per consecutive 12 months."

Response: Yes, once combined cycle operation is commenced, simple cycle operation of the four gas turbines shall not exceed an average of fuel equivalent of 1,000 hours per consecutive 12 months (1,741,176,400 SCF of gas per turbine). Operation of any simple cycle operation shall not exceed a fuel equivalent of 3,390 hours per consecutive 12 months. The requested condition would be on the same basis as the current limitation for Units 8A and 8B (see response to comment 6p).

Comment 5h: "Please explain the requested "aggregate" limit for simple cycle operation and oil firing after the combined cycle unit begins operation."

Response: During simple cycle operation the requested "aggregate" limit means that the maximum total combined hours of oil firing operation of the four CTs will not exceed a fuel equivalent of 2,000 hours. Each CT may operate in oil firing mode for a fuel equivalent of 500 hours per consecutive 12-month period or any combination of CT operating hours that is equivalent to 29,433,400 gallons; for example, if one CT uses 14,716,700 gallons (i.e. ½ of the aggregate limit), then the other three can only use 14,716,700 gallons or 4,905,566 gallons per CT.

Comment 5i: "Note that all requested annual limits will be specified in terms of 'consecutive 12 months'."

Response: The statement is acknowledged.

Comment 6a: "Emissions

Please provide General Electric's emissions data sheets for gas firing and oil firing including standard operation, power augmentation, and high temperature peaking at a compressor inlet air temperature of 59°F and 100-percent load."

Response: See Attachment A for GE data sheets for Units 8A and 8B. Units 8C and 8D will be similar.

Comment 6b: "Please provide the manufacturer's emissions data sheet for the duct burners. Provide supporting documents and/or calculations of the expected emission levels for the combined gas turbine exhaust and the duct burner emissions (CO, NO_x, and VOC)."

Response: The manufacturer of the duct burners has not been selected. The duct burner emissions presented in the application have been guaranteed on other similar projects. Attachment B presents typical information from duct burner manufacturers.

Comment 6c: "The proposed NO_x BACT emission rate of 12.0 ppmvd at 15-percent O_2 when firing oil in combined cycle mode is higher than recent Department permits, which have established a BACT limit of 10.0 ppmvd at 15-percent O_2 for an identical gas turbine controlled by SCR. Please comment."

Response: The NOx emission limit proposed for the turbines proposed for combined cycle operation when firing fuel oil and operating in combined cycle mode is 12 ppmvd at 15-percent O_2. This proposed NO_x emission limit balances the cost of the SCR system when designed for

2.5 ppmvd when firing natural gas. A lower limit for distillate will shift the design of the SCR system based on the oil limit. This increases the cost unnecessarily since oil is the alternate fuel.

Comment 6d: "The proposed NO_x BACT emission rate of 42.0 ppmvd at 15-percent O_2 when firing oil in simple cycle mode is higher than recent Department permits, which have established BACT limits as low as 36.0 ppmvd at 15-percent O_2 for an identical gas turbine controlled by wet injection. Please comment."

Response: The GE NO_x emission guarantee for the turbines proposed for the project when firing fuel oil and operating in simple cycle mode is 42 ppmvd at 15-percent O_2. The Department permitted Units 8A and 8B at this GE guaranteed limit when firing oil. The emission test report for Units 8A and 8B are being submitted to the commenter separately.

Comment 6e: "Please clarify the averaging period for the requested NO_x limit (3-hour or 24-hour; see page 2-4 and Table 4-1)."

Response: The footnote in Table 4-1 on page 2-4 of the application was incorrect. The requested averaging period for the NO_x limit is a 24-hour period as stated in Table 4-1 and included in the Emission Unit section of the application form.

Comment 6f: "General Electric has guaranteed CO emission rates of 7.4 and 14.4 ppmvd at 15-percent O_2 for gas and oil firing for the Frame 7FA gas turbine. Please explain the proposed CO BACT emission rates of 9 and 20 ppmvd at 15-percent O_2."

Response: The proposed CO BACT emission rates for CO are 9 and 20 ppmvd, not corrected to 15-percent O_2. The above mentioned 7.4 and 14.4 ppmvd at 15-percent O_2 emission rates are equivalent to the proposed 9 and 20 ppmvd. GE provides CO emission guarantees based on ppmvd and not corrected to 15-percent O_2, therefore the proposed emissions provided in the application are in units of ppmvd. The current CO limits for Units 8A and 8B are expressed in ppmvd.

Comment 6g: "The requested CO BACT emission rates of 24.5 ppmvd at 15-percent O_2 (gas firing with duct burning), 29.5 ppmvd at 15-percent O_2 (gas firing with duct burning and power augmentation or peaking), and 20.0 ppmvd at 15-percent O_2 (oil firing) do not represent current BACT levels of control for CO emissions. At these levels, the Department believes that an oxidation catalyst may be cost effective. Please comment."

Response: The requested CO BACT emission rates are in units of ppmvd not corrected to 15-percent O_2. The corresponding values of the requested CO emission rates in units of ppmvd at 15-percent O_2 are as follows:

- 14.7 ppmvd at 15-percent O_2 (gas firing with duct burning)
- 19.2 ppmvd at 15-percent O_2 (gas firing with duct burning and power augmentation or peaking)
- 14.1 ppmvd at 15-percent O_2 (oil firing)

Please refer to Tables A-2 and A-10 of the PSD Application (Appendix 10.1.5 of the SCA). Since GE provides CO emission guarantees based on ppmvd and not corrected to 15-percent O_2, the proposed emissions provided in the application are in units of ppmvd when duct firing. CO emission limits for other similarly large combined cycle projects (i.e., >500 MW) ranged from 16 ppmvd at 15-percent O_2 for the Hines Energy Complex to 17 ppmvd at 15-percent O_2 for the Osprey Energy Center. Both limits were 24-hour block averages.

The addition of an oxidation catalyst is not considered appropriate nor cost effective, given the "insignificant" ambient air impacts, collateral environmental effects and cost effectiveness. The cost effectiveness was estimated to be $4,165 per ton of CO removed. This also assumed maximum worst-case emissions, which is extremely conservative given the actual performance of the GE Frame 7FA as acknowledged by the department in recent permits. Moreover, there is no secondary environmental benefits of an oxidation catalyst since the amount of backpressure and lost energy ultimately results in the generation of more CO_2 than is being controlled in the oxidation catalyst (refer to Tables B-10 and B-11 in Appendix B of the Air Permit/PSD Application; Appendix 10.1.5 of the SCA).

Comment 6h: "Please provide supporting documentation that duct burning would increase CO emissions from 7.4 ppmvd at 15-percent O_2 to 24.5 ppmvd at 15-percent O_2 when firing natural gas. Verify that high temperature peaking would not increase CO emissions. Provide supporting documentation that duct burning with power augmentation would increase CO emissions from 24.5 ppmvd at 15-percent O_2 to 29.5 ppmvd at 15-percent O_2 when firing natural gas."

Response: This information was presented in Appendix A of the PSD Application (Appendix 10.1.5 of the SCA).

CO (lb/hr) = CO (ppm) x [1 - Moisture (percent)/100] x 2116.8 lb/ft^2 x Volume flow (acfm) x 28 (mole. wgt CO) x 60 min/hr / [1545 x (CT temp. (°F) + 460°F) x 1,000,000 (adj. for ppm)]

A. At an ambient temperature of 95° F, given the CT CO emission rate of 25.5 lb/hr based on the GE guarantee, and the duct burner (DB) CO emission rate of

0.08 lb/MMBtu and a heat input of 550 MMBtu/hr, the CT/DB emission rate is equivalent to 69.5 lb/hr. For this operating case, the moisture, temperature are as follows: 12.17 percent, 1143°F.

See Attachment C for the calculation of the volume flow rate for the CT and DB equal to 2,277,437 acfm.

The resulting CO ppmvd emission concentration equals 24.5 ppmvd or 14.7 ppmvd at 15-percent O_2.

B. At an ambient temperature of 80° F and operation in power augmentation, given the CT CO emission rate of 45 lb/hr based on the GE guarantee, and the duct burner (DB) CO emission rate of 0.08 lb/MMBtu and a heat input of 550 MMBtu/hr, the CT/DB emission rate is equivalent to 89 lb/hr. For this operating case, the moisture, temperature are as follows: 19.2 percent, 1125°F.

See Attachment C for the calculation of the volume flow rate for the CT and DB equal to 2,403,989 acfm.

The resulting CO ppmvd emission concentration equals 29.5 ppmvd or 19.2 ppmvd at 15-percent O_2.

Comment 6i: "The application requests EPA Method 10 testing to demonstrate compliance with the CO standards. Based on recent PSD permits for identical units, the Department intends to require a CO CEMS. Please comment. "

Response: The inclusion of continuous emission monitoring (CEM) for CO is not warranted based on performance of the turbines as well as the need relative to environmental considerations. The BACT analysis suggests that such CEM systems are not required given the "insignificant" ambient impact.

Comment 6j: "Please provide supporting documentation that duct burning would increase VOC emissions from 3.5 ppmvw to 7.0 ppmvw (when firing oil in the gas turbine)."

Response: Duct burners will not be fired during CT operation with light fuel oil. Based on GE guarantee data, the VOC emissions during light fuel oil firing will be 3.5 ppmvw. Duct burners will be fired only during natural gas operation of the CTs. The maximum VOC emission concentration during CT and duct burner firing will be 7.0 ppmvw. See Table A-2 of Appendix A in the Air Permit/PSD Application; Appendix 10.1.5 of the SCA.

Comment 6k: "The proposed visible emissions standard of 20-percent opacity when firing oil is inconsistent with recent Department permits for identical units, which limit opacity to 10 percent for all fuels. Please comment."

Response: An opacity limit of 10 percent is acceptable for the Project when firing natural gas or light distillate oil.

Comment 7a: "Excess Emissions: Please describe the 'steam blow' process and explain why 90 days of steam blows are necessary at the beginning of operation for this project."

Response: During construction, the steam piping systems internally accumulate weld spatter, slag, filings, and other debris. If this material is not removed prior to steam turbine operation, the steam turbine will be damaged by the metal particles, which would strike the blades and steam path vaning at very high velocities. Blowing through the piping system with steam removes this material, along with rust, grease, and other fabrication and construction residues prior to commencement of combined cycle operation.

The steam blow procedure involves firing the combustion turbine (CT) in order to generate steam in the heat recovery steam generator (HRSG), and then passing the steam through the piping towards the steam turbine. A temporary tee is installed in the steam line to divert the steam and foreign matter, to the atmosphere. Initial "steam blowing" is performed until the exhaust has no color, and then a polished target is inserted near the venting location, prior to subsequent blows. Blowing of steam through the line continues until the target shows limited "hits", according to an established criteria. When this criteria has been met, the line is considered clean. This method is used to clean the main high-pressure steam supply piping as well as the hot and cold reheat steam piping, steam bypass piping, and low pressure steam piping systems. These blows are carried out separately for each system, and in some cases, done in combination with other systems. Following the steam blow procedure of the four CT/HRSG sets, the steam blow procedure is done on the combined steam lines of the CT/HRSG to the main turbine.

The steam blow procedure is carried out at about 600 psi, which is less than the 2000 psi under normal operating conditions. This requires that the CT load be at less than 50 percent operating levels to supply the required steam. Further, it is desirable to thermally cycle the piping during the process, which requires CT shutdowns and restarts.

The 90-day period referenced for steam blow is the calendar duration from initiation of the process until completion for all four CT/HRSGs and mainstream lines to the steam turbine. The process will be intermittent throughout the 90-day period. There are numerous activities involved exclusive of the steam blow procedure. For example, temporary steam blow piping and valves must be removed and reinstalled for the various steam blowing operations. Occasionally, equipment repair or replacement is necessary; and there may be delays due to weather or other event. The duration of steam blowing is indeterminate but can be performed within the 90 day period requested.

Comment 7b: "Please describe the startup and shutdown procedures including the approximate lengths of time for each portion of the procedure (cold, warm, hot, simple cycle, and combined cycle)."

Response: In simple cycle operation, the CTs meet emission limits within about 30 minutes. In combined cycle, the startup of the combustion turbine involves controlling the exhaust temperature and flow, so as not to exceed limitations imposed by the HRSG manufacturer regarding rate of change of metal temperature change and metal temperature differentials. These limitations are reflected in maximum allowed increasing and decreasing HRSG ramp rates, and specified steam drum temperatures/pressures and durations.

The limitations result in the need for a relatively long startup time for the CT when the HRSG is cold. If the plant has been operating, and is then shutdown for more than 48 hours, the HRSG is considered to be cold. Then a 4-hour HRSG startup duration is required before the CT can be operated in at loads above 50 percent load when firing natural gas.

If the plant shut down is less than 48 hours, then the HRSG is considered to be warm, and a 2-hour HRSG startup duration is required before the CT can be operated at above 50-percent load when firing natural gas.

Similar startup limitations, imposed by the steam turbine manufacturer are designed into the turbine control system, and will apply when starting the steam turbine for combined cycle operation.

These limitations result in a total duration of 12 hours where loads of 50 percent will occur for the CTs. The CTs are started in sequence and the conditions of cold and warm startup would apply.

The startup will vary by the equipment vendors but presented below is a typical description of the process. During all startup conditions, the speed and load of the combustion turbines (CTs) are regulated to provide conditions that would not damage the HRSGs or steam turbine. The typical conditions described below.

1. Cold Start –Occurs when the combined cycle unit has been shutdown for more than 48 hours. The total time for this startup condition is 12 hours. The first CT is started and held at certain levels of heat input while the exhaust gases from the CT heat up the HRSG and produce steam for the steam turbine. The steam turbine starts load at about 2-hours into the start and load is applied to the CT at about 3 hours into the start. The second CT is started about 3 to 4 hours into the start with load applied at about 4 to 5 hours into the start. The third and fourth CTs are started in a similar sequence. At 12 hours into the start, all CTs are at a load that will comply with proposed emission limits.

2. Warm Start – Occurs when the combined cycle unit has been shutdown for 48 hours or less. The total time for this startup condition is about 2 hours. Similar to the cold start, the first CT is started and held at levels of heat input while the exhaust gases from the CT heat up the HRSG and produce steam for the steam turbine. The steam turbine starts load at about 1 hour into the start and load is applied to the CT at about shortly thereafter. The second CT is started about 1 hour into the start with load applied at about 1½ hours into the start. At two hours into the start, the first CT has reach full load with steam applied to the steam turbine. The other turbines are started in similar sequence.

Section 2.5.2 of the Air Permit/PSD Application (Appendix 10.1.5 of the SCA) proposed a condition for cold startup of Unit 8 that was identical to that previously approved by the department for the FPL Fort Myers Repowering Project.

Comment 7c: "What pollutants will be in 'excess' of an emissions standard, what are the expected levels, and what will be the expected duration? Please provide supporting documentation."

Response: The emissions in excess of the emission limits will be for the pollutants of NOx, CO and VOC. Emissions of PM and SO_2 are governed by primarily fuel quality. During steam blows, the CTs are operated at about at a load of about 12 MW, which is about 7-percent load. Based on GE estimates, the NOx emissions will be from 70 to 80 ppmvd corrected to 15-percent O_2. These emission rates will exceed the performance at 50-percent load and above. In addition, the SCR will not yet be installed and the operating temperature will not be sufficient. For CO and VOC the estimated emissions will be 100 ppmvd and 7 ppmvw, respectively.

During cold and warm starts the NOx emissions will vary between about 60 and 100 ppmvd corrected to 15-percent O_2. For CO emission will be highly variable any range between 20 and 1,000 ppmvd. Similarly, VOCs will vary between less than 2 ppmvd and 100 ppmvd.

<u>Comment 8a</u>: "SCR Costs

It appears that Tables B-3a and B-4a regarding hot SCR costs have been inadvertently omitted from the application. Please submit."

<u>Response</u>: These tables were inadvertently omitted and are provided as Attachment D.

<u>Comment 8b</u>: "Based on a report prepared for the Department of Energy (Onsite Sycom, 11/99), the hot SCR costs appear to be much higher than expected. This report indicates that annualized costs for "hot SCR" for a large frame unit would be approximately 20 percent higher than conventional SCR. The application indicates that the annualized cost for hot SCR would be 50 percent more than conventional SCR. Please provide the vendor quotes for both conventional SCR and hot SCR. Also, please provide the parameters submitted to the vendor for preparation of the bid."

<u>Response</u>: These are submitted as Attachment E. For combined-cycle operation, several vendor quotes were analyzed to determine the costs for SCR systems yielding NO_x control of 2.5 ppmvd at 15-percent O_2, see Appendix E. Based on these vendor data, the following methods were utilized to estimate SCR catalyst cost, and SCR system cost for a control system yielding 2.5 ppmvd at 15-percent O_2:

- The SCR catalyst cost for a 2.5 ppmvd at 15-percent O_2 system equals the cost of a 3.5 ppmvd at 15-percent O_2 system plus the difference in catalyst costs from systems of 4.5- and 3.5 ppmvd at 15-percent O_2.
- The SCR system cost for a 2.5 ppmvd at 15-percent O_2 system equals the system cost of a 3.5 ppmvd at 15-percent O_2 system plus the difference in catalyst cost of 3.5- and 2.5 ppmvd at 15-percent O_2 systems.

<u>Comment 8c</u>: "The Department disputes that hot SCR is "technically infeasible" as described in the application. Recent discussions with regulatory agencies in California indicate that such systems have been designed, installed, and are functioning properly. Please comment."

Response: In California, the majority of simple cycle projects with "hot" SCR are smaller gas turbines exclusively fired with natural gas. The proposed Project will utilize the GE Frame 7FA turbine with higher exhaust temperatures and will use light distillate oil as an alternate fuel. Based on the lack of demonstration of hot SCR on dual fuel gas turbines and anticipated technical difficulties associated with oil firing, hot SCR is not considered technically feasible for GE Frame 7FA turbines. Moreover, FDEP has concluded on many simple cycle projects that "hot" SCR is not appropriate as BACT. This includes Martin Units 8A and 8B (simple cycle). The Martin Unit 8 Project is a combined cycle project and FPL is seeking simple cycle operation only for a limited number of hours. This includes the first year of operation and limited operation when combined cycle operation has commenced. For combined cycle, SCR systems operating at 650 to 750°F are technically feasible, available and demonstrated for the Martin Unit 8 Project.

Comment 8d: "Page 4-12 lists four facilities with hot SCR installed on simple cycle units in the early 1990s, which had problems with catalyst deactivation. Did these facilities utilize the same high-temperature zeolite catalyst that is currently being offered by the Engelhard Corporation? Have improvements in high-temperature catalysts been made since these projects were installed? Does the exhaust gas of the GE Frame 7FA approach 1200°F frequently? Under what conditions? What is the maximum operating temperature for Engelhard's new zeolite catalyst?"

Response: Engelhard has installed the zeolite catalyst on GE 7EA units and has no experience with installation on GE 7 FA CTs. Currently the maximum temperature range for hot SCR is 650°F - 1050°F with the zeolite catalyst applied to a ceramic substrate. The exhaust temperature of the GE 7FA CT in simple cycle mode is frequently at or above the maximum zeolite catalyst temperature of 1100°F, see application Appendix 10.1, Tables 2-3 and 2-4. Engelhard is also the only supplier of "hot" SCR limiting the alternative.

Comment 8e: "For the purchased equipment costs identified in the Table B-3, was the catalyst included in this cost? The annualized cost table includes an 'annualized catalyst cost'. What methods were used to ensure that the catalyst component was not "double-counted?"

Response: The cost for the SCR catalyst is not "double-counted" in the economic analysis. The initial catalyst cost is included in the purchase equipment costs identified in Table B-3. This cost is then annualized. The replacement costs for the SCR catalyst are contained in the determination of annualized operating costs. The economic analysis employs the standard procedures found in the Office of Air Quality Planning and Standards (OAQPS) Control Cost Manual (EPA, 1996). This is a standard economic convention universally used in economic analyses.

Since the cost of the SCR catalyst is a large portion of the overall equipment cost, the annualized cost of equipment can also be estimated using an alternative approach to the economic analysis. In this approach the annualized capital cost of the catalyst and the annual replacement cost is omitted and replaced with a "recurring" capital cost. The recurring capital cost is based on the guaranteed life of the catalyst (3 years) and the 7 percent rate used in determining annualized cost. The capital recovery factor in this case is 0.3811. The following calculation using this method illustrated this alternative approach. The calculation is based on the costs presented in Table B-4 of the Air Permit/PSD Application for SCR at 3.5 ppmvd corrected to 15-percent O_2 (Appendix 10.1.5).

Annualized Cost in Table B-4	$1,136,656
Deletion of catalyst from annualized cost	-$68,625 ($625,000 x 0.1098)
Deletion of annual catalyst cost	-$214,583 ($625,000/3 x 1.03)
Annualized cost less catalyst	$853,448
Recurring Capital Cost	$238,187 ($625,000 x 0.3811)
Alternate Annualized Cost Calculation	$1,091,636 ($853,448 + 238,187)

Using this method the annualized cost is about 4 percent lower than the method used in the BACT analysis. This small difference does not substantially change the economic evaluation.

Comment 8f: "Please describe the calculation of the heat rate penalty in Table B-4. Does this cost include "lost revenue"? EPA guidance does not allow for the inclusion of "lost revenue" in determining control equipment costs for purposes of BACT. Please comment."

Response: Lost revenue is not included in determining the calculation of the heat rate penalty. The heat rate penalty in Table B-4 is based on 0.3 percent power output of the SCR and a 0.3 percent increase in the cost of producing that power. When there is a heat rate penalty, there is a concomitant loss of power produced as well as an increased cost to produce power. This increases the overall cost to produce power. The heat rate penalty is calculated as follows based on two components. The first accounts for cost associated with incremental cost of producing power (all incremental costs other than fuel) while the second accounts for increased fuel costs.

Heat Rate = (0.003)(172.3 MW Turbine Capacity)(8760 hr/year)(1000 kW/MW)($0.04/kWh)+ (0.003)(1,776 MMBtu)($3 MMBtu/scf)(8760 hr/year).

Comment 9a: "Catalytic Oxidation System Costs

Please provide the vendor quotes for the catalytic oxidation system, including the parameters submitted to the vendor for preparation of the bid."

Response: These are submitted as Attachment E.

Comment 9b: "For the purchased equipment costs identified in the Table B-8, was the catalyst included in this cost? The annualized cost table includes an 'annualized catalyst cost'. What methods were used to ensure that the catalyst component was not 'double-counted'?"

Response: The cost for the oxidation catalyst is not "double-counted" in the economic analysis. The initial catalyst cost is included in the purchase equipment costs identified in Table B-3. The replacement costs for the oxidation catalyst are contained in the determination of annualized operating costs. The economic analysis employs the standard procedures found in the Office of Air Quality Planning and Standards (OAQPS) Control Cost Manual (EPA, 1996). This is a standard economic convention universally used in economic analysis (See also Response to 6jj).

Comment 9c: "Please describe the calculation of the heat rate penalty in Table B-9. Does this cost include 'lost revenue'? EPA guidance does not allow for the inclusion of "lost revenue" in determining control equipment costs for purposes of BACT. Please comment."

Response: The heat rate penalty in Table B-9 is based on 0.2% power output of the CO Catalyst and a 0.2% increase in the cost of producing that power. When there is a heat rate penalty, there is a concomitant loss of power produced as well as an increased cost to produce power. This increases the cost to produce power. The heat rate penalty is calculated as follows (Refer to Comment 6kk):

Heat Rate = (0.002)(172.3 MW Turbine Capacity)(8760 hr/year)(1000 kW/MW)($0.04/kWh)+ (0.002)(1,776 MMBtu)($3/MMBtu gas cost)(8760 hr/year).

Comment 10: "Additional Air Quality Impacts Analysis: Please submit the following information as required by Rule 62-212.400(5)(h), F.A.C."

"Information relating to the air quality impacts of, and the nature and extent of, all general commercial, residential, industrial and other growth which has occurred since August 7,1977, in the area the facility or modification would affect."

Response: There has been minimal industrial, commercial, and residential growth within a 5-mile radius of the FPL Martin Plant site since 1977. The site itself consists of 11,300 acres that is wholly owned by FPL. The site is comprised of a 6,800-acre cooling pond and approximately 400 acres for the existing power facilities. The remaining area consists of undeveloped or agricultural land.

The plant is located in a rural area of Martin County that has a minimal number of air pollution industrial and commercial sources near the site. Since the baseline date of August 7, 1977, there has been one major facility (Indiantown Cogeneration) built and operating within a 10-mile radius. As presented in Section 6 of the Air Permit/PSD Application (Appendix 10.1.5), a cumulative impact analysis was conducted for SO_2 and included the Indiantown Cogeneration Facility.

There are also very few residences near the plant site. The site is almost completely surrounded by undeveloped or agricultural areas with no incorporated towns or cities within a 5-mile radius. A small, undeveloped portion of the community of Indiantown is located just within 5 miles of the site and a sparsely populated subdivision of Sunset Groves lies to the north of the site.

The existing commercial and industrial infrastructure should be adequate to provide any support services that the Project might require. Construction of the Project will occur over a 24-month period requiring an average of approximately 250 workers during that time. It is anticipated that many of these construction personnel will commute to the Site. At project build-out the plant will employ a total of 12 operational workers. This workforce needed to operate the proposed Project represents a small fraction of the population present in the immediate area. Population and housing impacts from construction and operation will be minimal because little migration into the area is anticipated. Additionally, there are expected to be no air quality impacts due to associated industrial/commercial growth given the location at the existing Martin Plant.

Since 1977, Martin County has been classified as attainment for all criteria pollutants. Although air monitoring data are not collected in the county, PM_{10}, O_3, and NO_2 concentrations are measured in St. Lucie County, located to the north of Martin County. These data are considered to be representative of air quality in Martin County due to the types and levels of air pollutants emitted from similar sources. Air monitoring data are collected for PM_{10}, O_3, SO_2 and CO in Palm Beach County, but these data are representative of air quality for areas with more industrial development than that around the Martin Plant site. The SO_2 and CO from Palm Beach County can be used, however, as a conservative indication of the air quality in Martin County.

A summary of the maximum pollutant concentrations measured in St. Lucie and Palm Beach Counties from 1998 through 2001 is presented in Table 2.3-13 of the SCA application. These data indicate that the maximum air quality concentrations measured in the region comply with and are well below the applicable ambient air quality standards.

Additionally, results of air modeling analyses demonstrate that the Project by itself and with other emission sources will comply with all applicable AAQS and PSD increments.

Comment 11: "EPA/NPS Comments: When received, the Department will forward any review submitted by the EPA Region 4 office or the National Park Service for comment. "

Response: Comment acknowledged. No comments were received as of the date of submittal of responses.

Comment 12: "Questions Regarding the Air Quality Analysis: The Department will submit questions and comments regarding its review of the air quality analysis before March 20, 2002."

Response: The Department did not provide comments regarding the air quality analysis.

ATTACHMENT A

GE DATA SHEETS FOR
UNITS 8A AND 8B

FPL MARTIN PLANT Distillate fuel
BASELOAD FOGGED TO 95% RH FROM 60 DEG-F
ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	BASE	BASE	BASE
Ambient Temp.	Deg F.	50.	60.	70.	80.
Evap. Cooler Status		None	On	On	On
Evap. Cooler Effectiveness	%		95	95	95
Fuel Type		Liquid	Liquid	Liquid	Liquid
Fuel LHV	Btu/lb	18,387	18,387	18,387	18,387
Fuel Temperature	Deg F	60	60	60	60
Liquid Fuel H/C Ratio		1.78	1.78	1.78	1.78
Output	kW	185,300.	184,000.	180,200.	175,800.
Heat Rate (LHV)	Btu/kWh	9,945.	9,940.	9,955.	9,985.
Heat Cons. (LHV) X 10^6	Btu/h	1,842.8	1,829.	1,793.9	1,755.4
Auxiliary Power	kW	1,390	1,390	1,390	1,390
Output Net	kW	183,910.	182,610.	178,810.	174,410.
Heat Rate (LHV) Net	Btu/kWh	10,020.	10,020.	10,030.	10,060.
Exhaust Flow X 10^3	lb/h	3750.	3719.	3649.	3573.
Exhaust Temp.	Deg F.	1089.	1093.	1102.	1111.
Exhaust Heat (LHV) X 10^6	Btu/h	1016.5	1012.5	996.4	980.4
Water Flow	lb/h	124,260.	119,340.	114,320.	107,900.

EMISSIONS

NOx	ppmvd @ 15% O2	42.	42.	42.	42.
NOx AS NO2	lb/h	325.	322.	316.	309.
CO	ppmvd	20.	20.	20.	20.
CO	lb/h	66.	65.	64.	62.
UHC	ppmvw	7.	7.	7.	7.
UHC	lb/h	15.	15.	14.	14.
VOC	ppmvw	3.5	3.5	3.5	3.5
VOC	lb/h	7.5	7.5	7.	7.
SO2	ppmvw	11.0	11.0	11.0	11.0
SO2	lb/h	95.0	94.0	93.0	91.0
SO3	ppmvw	1.0	1.0	1.0	1.0
SO3	lb/h	7.0	7.0	6.0	6.0
Sulfur Mist	lb/h	10.0	10.0	10.0	10.0
Particulates	lb/h	17.0	17.0	17.0	17.0

EXHAUST ANALYSIS % VOL.

Argon	0.86	0.85	0.86	0.85
Nitrogen	71.47	71.19	70.94	70.63
Oxygen	11.10	11.04	10.98	10.92
Carbon Dioxide	5.57	5.56	5.55	5.54
Water	11.01	11.37	11.68	12.07

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	60

Application	7FH2 Hydrogen-Cooled Generator
Combustion System	9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Liquid Fuel is Assumed to have 0.015% Fuel-Bound Nitrogen, or less.
FBN Amounts Greater Than 0.015% Will Add to the Reported NOx Value.
Sulfur Emissions Based On 0.05 WT% Sulfur Content in the Fuel.

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FPL MARTIN PLANT DISTILLATE FUEL GUARANTEE POINT
ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE
Ambient Temp.	Deg F.	75.
Output	kW	172,200.
Heat Rate (LHV)	Btu/kWh	10,090.
Heat Cons. (LHV) X 10^6	Btu/h	1,737.5
Auxiliary Power	kW	1,390
Output Net	kW	170,810.
Heat Rate (LHV) Net	Btu/kWh	10,170.
Exhaust Flow X 10^3	lb/h	3552.
Exhaust Temp.	Deg F.	1113.
Exhaust Heat (LHV) X 10^6	Btu/h	971.0
Water Flow	lb/h	111,950.
EMISSIONS		
NOx	ppmvd @ 15% O2	42.
NOx AS NO2	lb/h	307.
CO	ppmvd	20.
CO	lb/h	62.
UHC	ppmvw	7.
UHC	lb/h	14.
VOC	ppmvw	3.5
VOC	lb/h	7.
SO2	ppmvw	11.0
SO2	lb/h	90.0
SO3	ppmvw	1.0
SO3	lb/h	6.0
Sulfur Mist	lb/h	9.0
Particulates	lb/h	17.0
EXHAUST ANALYSIS	% VOL.	
Argon		0.85
Nitrogen		70.94
Oxygen		11.00
Carbon Dioxide		5.54
Water		11.68
SITE CONDITIONS		
Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Fuel Type		Liquid Fuel, H/C Ratio Of 1.82
Fuel LHV	Btu/lb	18387 @ 60 °F
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.
Liquid Fuel is Assumed to have 0.015% Fuel-Bound Nitrogen, or less.
FBN Amounts Greater Than 0.015% Will Add to the Reported NOx Value.
Sulfur Emissions Based On 0.05 WT% Sulfur Content in the Fuel.
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FPL Martin Plant Distillate Fuel Base Load over ambient range
ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	BASE	BASE	BASE	BASE
Ambient Temp.	Deg F.	0.	35.	59.	75.	95.
Ambient Relative Humid.	%	2.0	20.0	60.0	60.0	50.0
Fuel Type		Liquid	Liquid	Liquid	Liquid	Liquid
Fuel LHV	Btu/lb	18,387	18,387	18,387	18,387	18,387
Fuel Temperature	Deg F	60	60	60	60	60
Liquid Fuel H/C Ratio		1.82	1.78	1.78	1.78	1.78
Output	kW	192,400.	190,500.	181,800.	173,900.	160,600.
Heat Rate (LHV)	Btu/kWh	10,110.	9,945.	9,960.	10,020.	10,190.
Heat Cons. (LHV) X 10^6	Btu/h	1,945.2	1,894.5	1,810.7	1,742.5	1,636.5
Auxiliary Power	kW	1,390	1,390	1,390	1,390	1,390
Output Net	kW	191,010.	189,110.	180,410.	172,510.	159,210.
Heat Rate (LHV) Net	Btu/kWh	10,180.	10,020.	10,040.	10,100.	10,280.
Exhaust Flow X 10^3	lb/h	3928.	3862.	3683.	3552.	3376.
Exhaust Temp.	Deg F.	1066.	1074.	1098.	1113.	1131.
Exhaust Heat (LHV) X 10^6	Btu/h	1082.9	1042.6	1000.7	970.1	926.3
Water Flow	lb/h	134,140.	130,930.	120,720.	111,950.	98,570.

EMISSIONS

NOx	ppmvd @ 15% O2	42.	42.	42.	42.	42.
NOx AS NO2	lb/h	343.	334.	319.	307.	289.
CO	ppmvd	20.	20.	20.	20.	20.
CO	lb/h	69.	68.	65.	62.	59.
UHC	ppmvw	7.	7.	7.	7.	7.
UHC	lb/h	15.	15.	15.	14.	13.
VOC	ppmvw	3.5	3.5	3.5	3.5	3.5
VOC	lb/h	7.5	7.5	7.5	7.	6.5
SO2	ppmvw	12.0	11.0	11.0	11.0	11.0
SO2	lb/h	101.0	98.0	94.0	90.0	85.0
SO3	ppmvw	0.0	1.0	1.0	1.0	1.0
SO3	lb/h	6.0	6.0	6.0	6.0	5.0
Sulfur Mist	lb/h	11.0	10.0	10.0	9.0	9.0
Particulates	lb/h	17.0	17.0	17.0	17.0	17.0

EXHAUST ANALYSIS % VOL.

Argon	0.85	0.86	0.86	0.85	0.85
Nitrogen	71.84	71.79	71.31	70.94	70.52
Oxygen	11.13	11.19	11.06	11.00	11.00
Carbon Dioxide	5.62	5.56	5.56	5.54	5.46
Water	10.56	10.60	11.21	11.68	12.18

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Liquid Fuel is Assumed to have 0.015% Fuel-Bound Nitrogen, or less.
FBN Amounts Greater Than 0.015% Will Add to the Reported NOx Value.
Sulfur Emissions Based On 0.05 WT% Sulfur Content in the Fuel.

IPS- version code- 2 . 0 . 1 Opt: 9 72410996
HENRYCO 01/28/2000 17:58 FPL Martin dis BL rge

FPL MARTIN PLANT Distillate Fuel
LOAD RANGE AT 0 DEGF AND NEGLEGIBLE REL.HUMIDITY
ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%
Ambient Temp.	Deg F.	0.	0.	0.
Fuel Type		Liquid	Liquid	Liquid
Fuel LHV	Btu/lb	18,387	18,387	18,387
Fuel Temperature	Deg F	60	60	60
Liquid Fuel H/C Ratio		1.78	1.78	1.78
Output	kW	192,400.	144,300.	96,200.
Heat Rate (LHV)	Btu/kWh	10,110.	10,680.	12,630.
Heat Cons. (LHV) X 10^6	Btu/h	1,945.2	1,541.1	1,215.
Auxiliary Power	kW	1,390	1,390	1,390
Output Net	kW	191,010.	142,910.	94,810.
Heat Rate (LHV) Net	Btu/kWh	10,180.	10,780.	12,820.
Exhaust Flow X 10^3	lb/h	3928.	3076.	2521.
Exhaust Temp.	Deg F.	1066.	1107.	1154.
Exhaust Heat (LHV) X 10^6	Btu/h	1082.9	895.2	772.8
Water Flow	lb/h	134,140.	96,540.	67,700.

EMISSIONS

NOx	ppmvd @ 15% O2	42.	42.	42.
NOx AS NO2	lb/h	343.	269.	210.
CO	ppmvd	20.	25.	36.
CO	lb/h	69.	69.	81.
UHC	ppmvw	7.	7.	7.
UHC	lb/h	15.	12.	10.
VOC	ppmvw	3.5	3.5	3.5
VOC	lb/h	7.5	6.	5.
SO2	ppmvw	12.0	12.0	11.0
SO2	lb/h	101.0	80.0	63.0
SO3	ppmvw	<1.0	<1.0	1.0
SO3	lb/h	6.0	5.0	4.0
Sulfur Mist	lb/h	11.0	8.0	7.0
Particulates	lb/h	17.0	17.0	17.0

EXHAUST ANALYSIS % VOL.

Argon	0.85	0.85	0.87
Nitrogen	71.84	72.17	72.81
Oxygen	11.13	11.19	11.73
Carbon Dioxide	5.62	5.64	5.38
Water	10.56	10.15	9.21

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	2
Application		7FH2 Hydrogen-Cooled Generator

Combustion System 9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Liquid Fuel is Assumed to have 0.015% Fuel-Bound Nitrogen, or less.
FBN Amounts Greater Than 0.015% Will Add to the Reported NOx Value.
Sulfur Emissions Based On 0.05 WT% Sulfur Content in the Fuel.

IPS- version code- 2 . 0 . 1 Opt: 9 72410996
HENRYCO 01/28/2000 17:59 FPL Martin dis load rge 0

FPL MARTIN PLANT Distillate Fuel
LOAD RANGE AT 35 DEGF AND 20% REL.HUMIDITY

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%
Ambient Temp.	Deg F.	35.	35.	35.
Fuel Type		Liquid	Liquid	Liquid
Fuel LHV	Btu/lb	18,387	18,387	18,387
Fuel Temperature	Deg F	60	60	60
Liquid Fuel H/C Ratio		1.78	1.78	1.78
Output	kW	190,500.	142,900.	95,200.
Heat Rate (LHV)	Btu/kWh	9,945.	10,550.	12,500.
Heat Cons. (LHV) X 10^6	Btu/h	1,894.5	1,507.6	1,190.
Auxiliary Power	kW	1,390	1,390	1,390
Output Net	kW	189,110.	141,510.	93,810.
Heat Rate (LHV) Net	Btu/kWh	10,020.	10,650.	12,690.
Exhaust Flow X 10^3	lb/h	3862.	3024.	2487.
Exhaust Temp.	Deg F.	1074.	1121.	1168.
Exhaust Heat (LHV) X 10^6	Btu/h	1042.6	868.7	752.4
Water Flow	lb/h	130,930.	94,620.	66,770.

EMISSIONS

NOx	ppmvd @ 15% O2	42.	42.	42.
NOx AS NO2	lb/h	334.	263.	206.
CO	ppmvd	20.	24.	35.
CO	lb/h	68.	65.	77.
UHC	ppmvw	7.	7.	7.
UHC	lb/h	15.	12.	10.
VOC	ppmvw	3.5	3.5	3.5
VOC	lb/h	7.5	6.	5.
SO2	ppmvw	11.0	12.0	11.0
SO2	lb/h	98.0	78.0	61.0
SO3	ppmvw	1.0	<1.0	1.0
SO3	lb/h	6.0	5.0	5.0
Sulfur Mist	lb/h	10.0	8.0	6.0
Particulates	lb/h	17.0	17.0	17.0

EXHAUST ANALYSIS % VOL.

Argon	0.86	0.86	0.87
Nitrogen	71.79	72.10	72.73
Oxygen	11.19	11.22	11.76
Carbon Dioxide	5.56	5.60	5.35
Water	10.60	10.23	9.29

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	20
Application		7FH2 Hydrogen-Cooled Generator

Combustion System 9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Liquid Fuel is Assumed to have 0.015% Fuel-Bound Nitrogen, or less.
FBN Amounts Greater Than 0.015% Will Add to the Reported NOx Value.
Sulfur Emissions Based On 0.05 WT% Sulfur Content in the Fuel.

IPS- version code- 2 . 0 . 1 Opt: 9 72410996
HENRYCO 01/28/2000 18:00 FPL Martin dis load rge 35

FPL MARTIN PLANT Distillate Fuel
LOAD RANGE AT 59 DEGF AND 60% REL.HUMIDITY
ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%
Ambient Temp.	Deg F.	59.	59.	59.
Fuel Type		Liquid	Liquid	Liquid
Fuel LHV	Btu/lb	18,387	18,387	18,387
Fuel Temperature	Deg F	60	60	60
Liquid Fuel H/C Ratio		1.78	1.78	1.78
Output	kW	181,800.	136,400.	90,900.
Heat Rate (LHV)	Btu/kWh	9,960.	10,620.	12,670.
Heat Cons. (LHV) X 10^6	Btu/h	1,810.7	1,448.6	1,151.7
Auxiliary Power	kW	1,390	1,390	1,390
Output Net	kW	180,410.	135,010.	89,510.
Heat Rate (LHV) Net	Btu/kWh	10,040.	10,730.	12,870.
Exhaust Flow X 10^3	lb/h	3683.	2936.	2435.
Exhaust Temp.	Deg F.	1098.	1137.	1182.
Exhaust Heat (LHV) X 10^6	Btu/h	1000.7	841.4	734.9
Water Flow	lb/h	120,720.	86,500.	61,390.

EMISSIONS

NOx	ppmvd @ 15% O2	42.	42.	42.
NOx AS NO2	lb/h	319.	253.	199.
CO	ppmvd	20.	24.	34.
CO	lb/h	65.	61.	73.
UHC	ppmvw	7.	7.	7.
UHC	lb/h	15.	12.	10.
VOC	ppmvw	3.5	3.5	3.5
VOC	lb/h	7.5	6.	5.
SO2	ppmvw	11.0	12.0	11.0
SO2	lb/h	94.0	75.0	60.0
SO3	ppmvw	1.0	<1.0	1.0
SO3	lb/h	6.0	5.0	3.0
Sulfur Mist	lb/h	10.0	8.0	6.0
Particulates	lb/h	17.0	17.0	17.0

EXHAUST ANALYSIS % VOL.

Argon	0.86	0.86	0.88
Nitrogen	71.31	71.72	72.33
Oxygen	11.06	11.21	11.76
Carbon Dioxide	5.56	5.54	5.27
Water	11.21	10.68	9.77

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Application		7FH2 Hydrogen-Cooled Generator

Combustion System 9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Liquid Fuel is Assumed to have 0.015% Fuel-Bound Nitrogen, or less.
FBN Amounts Greater Than 0.015% Will Add to the Reported NOx Value.
Sulfur Emissions Based On 0.05 WT% Sulfur Content in the Fuel.

IPS- version code- 2 . 0 . 1 Opt: 9 72410996
HENRYCO 01/28/2000 18:01 FPL Martin dis load rge 59

FPL MARTIN PLANT Distillate Fuel
LOAD RANGE AT 75 DEGF AND 60% REL.HUMIDITY
ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%
Ambient Temp.	Deg F.	75.	75.	75.
Fuel Type		Liquid	Liquid	Liquid
Fuel LHV	Btu/lb	18,387	18,387	18,387
Fuel Temperature	Deg F	60	60	60
Liquid Fuel H/C Ratio		1.78	1.78	1.78
Output	kW	173,900.	130,500.	87,000.
Heat Rate (LHV)	Btu/kWh	10,020.	10,750.	12,860.
Heat Cons. (LHV) X 10^6	Btu/h	1,742.5	1,402.9	1,118.8
Auxiliary Power	kW	1,390	1,390	1,390
Output Net	kW	172,510.	129,110.	85,610.
Heat Rate (LHV) Net	Btu/kWh	10,100.	10,870.	13,070.
Exhaust Flow X 10^3	lb/h	3552.	2871.	2389.
Exhaust Temp.	Deg F.	1113.	1149.	1193.
Exhaust Heat (LHV) X 10^6	Btu/h	970.1	823.5	721.0
Water Flow	lb/h	111,950.	80,050.	56,630.

EMISSIONS

NOx	ppmvd @ 15% O2	42.	42.	42.
NOx AS NO2	lb/h	307.	245.	193.
CO	ppmvd	20.	23.	34.
CO	lb/h	62.	59.	71.
UHC	ppmvw	7.	7.	7.
UHC	lb/h	14.	11.	9.
VOC	ppmvw	3.5	3.5	3.5
VOC	lb/h	7.	5.5	4.5
SO2	ppmvw	11.0	11.0	11.0
SO2	lb/h	90.0	72.0	58.0
SO3	ppmvw	1.0	1.0	<1.0
SO3	lb/h	6.0	5.0	4.0
Sulfur Mist	lb/h	9.0	8.0	6.0
Particulates	lb/h	17.0	17.0	17.0

EXHAUST ANALYSIS % VOL.

Argon	0.85	0.85	0.86
Nitrogen	70.94	71.40	72.00
Oxygen	11.00	11.22	11.77
Carbon Dioxide	5.54	5.47	5.21
Water	11.68	11.06	10.17

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Liquid Fuel is Assumed to have 0.015% Fuel-Bound Nitrogen, or less.
FBN Amounts Greater Than 0.015% Will Add to the Reported NOx Value.
Sulfur Emissions Based On 0.05 WT% Sulfur Content in the Fuel.

IPS- version code- 2 . 0 . 1 Opt: 9 72410996
HENRYCO 01/28/2000 18:02 FPL Martin dis load rge 75

FPL MARTIN PLANT Distillate Fuel
LOAD RANGE AT 95 DEGF AND 50% REL.HUMIDITY
ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%
Ambient Temp.	Deg F.	95.	95.	95.
Fuel Type		Liquid	Liquid	Liquid
Fuel LHV	Btu/lb	18,387	18,387	18,387
Fuel Temperature	Deg F	60	60	60
Liquid Fuel H/C Ratio		1.78	1.78	1.78
Output	kW	160,600.	120,500.	80,300.
Heat Rate (LHV)	Btu/kWh	10,190.	11,010.	13,220.
Heat Cons. (LHV) X 10^6	Btu/h	1,636.5	1,326.7	1,061.6
Auxiliary Power	kW	1,390	1,390	1,390
Output Net	kW	159,210.	119,110.	78,910.
Heat Rate (LHV) Net	Btu/kWh	10,280.	11,140.	13,450.
Exhaust Flow X 10^3	lb/h	3376.	2758.	2323.
Exhaust Temp.	Deg F.	1131.	1166.	1200.
Exhaust Heat (LHV) X 10^6	Btu/h	926.3	793.5	695.9
Water Flow	lb/h	98,570.	70,300.	49,100.

EMISSIONS

NOx	ppmvd @ 15% O2	42.	42.	42.
NOx AS NO2	lb/h	289.	232.	183.
CO	ppmvd	20.	24.	36.
CO	lb/h	59.	57.	74.
UHC	ppmvw	7.	7.	7.
UHC	lb/h	13.	11.	9.
VOC	ppmvw	3.5	3.5	3.5
VOC	lb/h	6.5	5.5	4.5
SO2	ppmvw	11.0	11.0	11.0
SO2	lb/h	85.0	69.0	55.0
SO3	ppmvw	1.0	1.0	<1.0
SO3	lb/h	5.0	4.0	3.0
Sulfur Mist	lb/h	9.0	7.0	6.0
Particulates	lb/h	17.0	17.0	17.0

EXHAUST ANALYSIS % VOL.

Argon		0.85	0.85	0.87
Nitrogen		70.52	70.99	71.61
Oxygen		11.00	11.25	11.86
Carbon Dioxide		5.46	5.38	5.07
Water		12.18	11.54	10.60

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	50
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Liquid Fuel is Assumed to have 0.015% Fuel-Bound Nitrogen, or less.
FBN Amounts Greater Than 0.015% Will Add to the Reported NOx Value.
Sulfur Emissions Based On 0.05 WT% Sulfur Content in the Fuel.

IPS- version code- 2 . 0 . 1 Opt: 9 72410996
HENRYCO 01/28/2000 18:03 FPL Martin dis load rge 95

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	BASE	BASE	BASE
Ambient Temp.	Deg F.	50.	60.	70.	80.
Evap. Cooler Status		None	On	On	On
Evap. Cooler Effectiveness	%		95	95	95
Fuel Type		Cust Gas	Cust Gas	Cust Gas	Cust Gas
Fuel LHV	Btu/lb	20,835	20,835	20,835	20,835
Fuel Temperature	Deg F	290	290	290	290
Output	kW	177,200.	176,000.	171,700.	166,700.
Heat Rate (LHV)	Btu/kWh	9,215.	9,235.	9,280.	9,350.
Heat Cons. (LHV) X 10^6	Btu/h	1,632.9	1,625.4	1,593.4	1,558.6
Auxiliary Power	kW	560	560	560	560
Output Net	kW	176,640.	175,440.	171,140.	166,140.
Heat Rate (LHV) Net	Btu/kWh	9,240.	9,260.	9,310.	9,380.
Exhaust Flow X 10^3	lb/h	3602.	3577.	3512.	3444.
Exhaust Temp.	Deg F.	1110.	1113.	1119.	1125.
Exhaust Heat (LHV) X 10^6	Btu/h	969.0	965.8	949.6	933.2

EMISSIONS

NOx	ppmvd @ 15% O2	9.	9.	9.	9.
NOx AS NO2	lb/h	60.	60.	58.	57.
CO	ppmvd	9.	9.	9.	9.
CO	lb/h	29.	29.	28.	28.
UHC	ppmvw	7.	7.	7.	7.
UHC	lb/h	14.	14.	14.	14.
VOC	ppmvw	1.4	1.4	1.4	1.4
VOC	lb/h	2.8	2.8	2.8	2.8
Particulates	lb/h	9.0	9.0	9.0	9.0

EXHAUST ANALYSIS % VOL.

Argon	0.88	0.89	0.88	0.88
Nitrogen	74.62	74.19	73.84	73.38
Oxygen	12.47	12.35	12.28	12.19
Carbon Dioxide	3.89	3.89	3.87	3.86
Water	8.14	8.69	9.13	9.70

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Sulfur Emissions Based On 0.0002 WT% Sulfur Content in the Fuel.

IPS- version code- 2 . 0 . 1 Opt: 9 72410996
HENRYCO 01/28/2000 18:39FPL Martin gas BL fogg rge

FPL Martin Plant Gas Fuel Guarantee Point
ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE
Ambient Temp.	Deg F.	75.
Output	kW	162,100.
Heat Rate (LHV)	Btu/kWh	9,440.
Heat Cons. (LHV) X 10^6	Btu/h	1,530.2
Auxiliary Power	kW	560
Output Net	kW	161,540.
Heat Rate (LHV) Net	Btu/kWh	9,470.
Exhaust Flow X 10^3	lb/h	3418.
Exhaust Temp.	Deg F.	1128.
Exhaust Heat (LHV) X 10^6	Btu/h	921.4

EMISSIONS

NOx	ppmvd @ 15% O2	9.
NOx AS NO2	lb/h	56.
CO	ppmvd	9.
CO	lb/h	28.
UHC	ppmvw	7.
UHC	lb/h	14.
VOC	ppmvw	1.4
VOC	lb/h	2.8
Particulates	lb/h	9.0

EXHAUST ANALYSIS % VOL.

Argon	0.89
Nitrogen	73.88
Oxygen	12.36
Carbon Dioxide	3.84
Water	9.04

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Fuel Type		Cust Gas
Fuel LHV	Btu/lb	20835 @ 290 °F
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.
Sulfur Emissions Based On 0.0002 WT% Sulfur Content in the Fuel.
IPS- 90973 version code- 2 . 0 . 1 Opt: N 72410996
HENRYCO 01/28/2000 17:20 FPL Martin gas BL rge

Gas Fuel

LOAD RANGE AT 0 DEGF AND NEGLEGIBLE REL.HUMIDITY

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%
Ambient Temp.	Deg F.	0.	0.	0.
Fuel Type		Cust Gas	Cust Gas	Cust Gas
Fuel LHV	Btu/lb	20,835	20,835	20,835
Fuel Temperature	Deg F	290	290	290
Output	kW	189,100.	141,800.	94,600.
Heat Rate (LHV)	Btu/kWh	9,250.	9,860.	11,780.
Heat Cons. (LHV) X 10^6	Btu/h	1,749.2	1,398.1	1,114.4
Auxiliary Power	kW	560	560	560
Output Net	kW	188,540.	141,240.	94,040.
Heat Rate (LHV) Net	Btu/kWh	9,280.	9,900.	11,850.
Exhaust Flow X 10^3	lb/h	3885.	3070.	2514.
Exhaust Temp.	Deg F.	1068.	1101.	1149.
Exhaust Heat (LHV) X 10^6	Btu/h	1040.5	863.3	750.0
EMISSIONS				
NOx	ppmvd @ 15% O2	9.	9.	9.
NOx AS NO2	lb/h	64.	51.	40.
CO	ppmvd	9.	9.	9.
CO	lb/h	32.	25.	21.
UHC	ppmvw	7.	7.	7.
UHC	lb/h	15.	12.	10.
VOC	ppmvw	1.4	1.4	1.4
VOC	lb/h	3.	2.4	2.
Particulates	lb/h	9.0	9.0	9.0
EXHAUST ANALYSIS	% VOL.			
Argon		0.89	0.89	0.89
Nitrogen		75.18	75.17	75.28
Oxygen		12.65	12.64	12.94
Carbon Dioxide		3.87	3.88	3.74
Water		7.41	7.42	7.15
SITE CONDITIONS				
Elevation	ft.	45.0		
Site Pressure	psia	14.68		
Inlet Loss	in Water	3.0		
Exhaust Loss	in Water	5.5		
Relative Humidity	%	3		
Application		7FH2 Hydrogen-Cooled Generator		
Combustion System		9/42 DLN Combustor		

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Sulfur Emissions Based On 0.0002 WT% Sulfur Content in the Fuel.

IPS- 90973 version code- 2 . 0 . 1 Opt: 9 72410996

HENRYCO 01/28/2000 17:34 gas BL LOAD rge 0

FPL Martin Plant Gas Fuel
LOAD RANGE AT 35 DEGF AND 20% REL.HUMIDITY
ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%
Ambient Temp.	Deg F.	35.	35.	35.
Fuel Type		Cust Gas	Cust Gas	Cust Gas
Fuel LHV	Btu/lb	20,835	20,835	20,835
Fuel Temperature	Deg F	290	290	290
Output	kW	182,200.	136,700.	91,100.
Heat Rate (LHV)	Btu/kWh	9,185.	9,855.	11,820.
Heat Cons. (LHV) X 10^6	Btu/h	1,673.5	1,347.2	1,076.8
Auxiliary Power	kW	560	560	560
Output Net	kW	181,640.	136,140.	90,540.
Heat Rate (LHV) Net	Btu/kWh	9,210.	9,900.	11,890.
Exhaust Flow X 10^3	lb/h	3706.	2979.	2456.
Exhaust Temp.	Deg F.	1095.	1122.	1168.
Exhaust Heat (LHV) X 10^6	Btu/h	991.1	831.5	725.6
EMISSIONS				
NOx	ppmvd @ 15% O2	9.	9.	9.
NOx AS NO2	lb/h	61.	49.	39.
CO	ppmvd	9.	9.	9.
CO	lb/h	30.	24.	20.
UHC	ppmvw	7.	7.	7.
UHC	lb/h	15.	12.	10.
VOC	ppmvw	1.4	1.4	1.4
VOC	lb/h	3.	2.4	2.
Particulates	lb/h	9.0	9.0	9.0
EXHAUST ANALYSIS	% VOL.			
Argon		0.90	0.90	0.90
Nitrogen		75.07	75.10	75.21
Oxygen		12.60	12.67	12.99
Carbon Dioxide		3.88	3.85	3.70
Water		7.56	7.49	7.21
SITE CONDITIONS				
Elevation	ft.	45.0		
Site Pressure	psia	14.68		
Inlet Loss	in Water	3.0		
Exhaust Loss	in Water	5.5		
Relative Humidity	%	20		
Application		7FH2 Hydrogen-Cooled Generator		
Combustion System		9/42 DLN Combustor		

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Sulfur Emissions Based On 0.0002 WT% Sulfur Content in the Fuel.

IPS- 90973 version code- 2 . 0 . 1 Opt: 9 72410996
HENRYCO 01/28/2000 17:44 FPL Martin gas BL LOAD rge 35

FPL Martin Plant Gas Fuel
LOAD RANGE AT 59 DEGF AND 60% REL.HUMIDITY
ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%
Ambient Temp.	Deg F.	59.	59.	59.
Fuel Type		Cust Gas	Cust Gas	Cust Gas
Fuel LHV	Btu/lb	20,835	20,835	20,835
Fuel Temperature	Deg F	290	290	290
Output	kW	173,000.	129,800.	86,500.
Heat Rate (LHV)	Btu/kWh	9,250.	10,000.	12,050.
Heat Cons. (LHV) X 10^6	Btu/h	1,600.3	1,298.	1,042.3
Auxiliary Power	kW	560	560	560
Output Net	kW	172,440.	129,240.	85,940.
Heat Rate (LHV) Net	Btu/kWh	9,280.	10,040.	12,130.
Exhaust Flow X 10^3	lb/h	3539.	2888.	2396.
Exhaust Temp.	Deg F.	1116.	1139.	1184.
Exhaust Heat (LHV) X 10^6	Btu/h	951.8	807.5	707.9
EMISSIONS				
NOx	ppmvd @ 15% O2	9.	9.	9.
NOx AS NO2	lb/h	59.	47.	37.
CO	ppmvd	9.	9.	9.
CO	lb/h	29.	24.	20.
UHC	ppmvw	7.	7.	7.
UHC	lb/h	14.	11.	9.
VOC	ppmvw	1.4	1.4	1.4
VOC	lb/h	2.8	2.2	1.8
Particulates	lb/h	9.0	9.0	9.0
EXHAUST ANALYSIS	% VOL.			
Argon		0.88	0.90	0.90
Nitrogen		74.42	74.46	74.58
Oxygen		12.44	12.57	12.90
Carbon Dioxide		3.87	3.81	3.66
Water		8.39	8.27	7.97
SITE CONDITIONS				
Elevation	ft.	45.0		
Site Pressure	psia	14.68		
Inlet Loss	in Water	3.0		
Exhaust Loss	in Water	5.5		
Relative Humidity	%	60		
Application		7FH2 Hydrogen-Cooled Generator		
Combustion System		9/42 DLN Combustor		

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Sulfur Emissions Based On 0.0002 WT% Sulfur Content in the Fuel.

IPS- 90973 version code- 2 . 0 . 1 Opt: 9 72410996
HENRYCO 01/28/2000 17:45 FPL Martin gas BL LOAD rge 59

FPL Martin Plant Gas Fuel
LOAD RANGE AT 75 DEGF AND 60% REL.HUMIDITY
ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%
Ambient Temp.	Deg F.	75.	75.	75.
Fuel Type		Cust Gas	Cust Gas	Cust Gas
Fuel LHV	Btu/lb	20,835	20,835	20,835
Fuel Temperature	Deg F	290	290	290
Output	kW	163,700.	122,800.	81,900.
Heat Rate (LHV)	Btu/kWh	9,380.	10,190.	12,330.
Heat Cons. (LHV) X 10^6	Btu/h	1,535.5	1,251.3	1,009.8
Auxiliary Power	kW	560	560	560
Output Net	kW	163,140.	122,240.	81,340.
Heat Rate (LHV) Net	Btu/kWh	9,410.	10,240.	12,410.
Exhaust Flow X 10^3	lb/h	3418.	2803.	2336.
Exhaust Temp.	Deg F.	1128.	1153.	1195.
Exhaust Heat (LHV) X 10^6	Btu/h	921.1	786.3	692.2
EMISSIONS				
NOx	ppmvd @ 15% O2	9.	9.	9.
NOx AS NO2	lb/h	56.	45.	36.
CO	ppmvd	9.	9.	9.
CO	lb/h	28.	23.	19.
UHC	ppmvw	7.	7.	7.
UHC	lb/h	14.	11.	9.
VOC	ppmvw	1.4	1.4	1.4
VOC	lb/h	2.8	2.2	1.8
Particulates	lb/h	9.0	9.0	9.0
EXHAUST ANALYSIS	% VOL.			
Argon		0.89	0.88	0.89
Nitrogen		73.88	73.93	74.04
Oxygen		12.36	12.49	12.83
Carbon Dioxide		3.84	3.78	3.62
Water		9.04	8.92	8.62

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Sulfur Emissions Based On 0.0002 WT% Sulfur Content in the Fuel.

IPS- 90973 version code- 2 . 0 . 1 Opt: 9 72410996
HENRYCO 01/28/2000 17:54 FPL Martin gas BL LOAD rge 75

FPL Martin Plant Gas Fuel
LOAD RANGE AT 95 DEGF AND 50% REL.HUMIDITY
ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%
Ambient Temp.	Deg F.	95.	95.	95.
Fuel Type		Cust Gas	Cust Gas	Cust Gas
Fuel LHV	Btu/lb	20,835	20,835	20,835
Fuel Temperature	Deg F	290	290	290
Output	kW	150,300.	112,800.	75,200.
Heat Rate (LHV)	Btu/kWh	9,630.	10,550.	12,770.
Heat Cons. (LHV) X 10^6	Btu/h	1,447.4	1,190.	960.3
Auxiliary Power	kW	560	560	560
Output Net	kW	149,740.	112,240.	74,640.
Heat Rate (LHV) Net	Btu/kWh	9,670.	10,600.	12,870.
Exhaust Flow X 10^3	lb/h	3257.	2694.	2267.
Exhaust Temp.	Deg F.	1143.	1170.	1200.
Exhaust Heat (LHV) X 10^6	Btu/h	881.8	761.2	667.1
EMISSIONS				
NOx	ppmvd @ 15% O2	9.	9.	9.
NOx AS NO2	lb/h	53.	43.	35.
CO	ppmvd	9.	9.	9.
CO	lb/h	26.	22.	18.
UHC	ppmvw	7.	7.	7.
UHC	lb/h	13.	11.	9.
VOC	ppmvw	1.4	1.4	1.4
VOC	lb/h	2.6	2.2	1.8
Particulates	lb/h	9.0	9.0	9.0
EXHAUST ANALYSIS	% VOL.			
Argon		0.88	0.87	0.87
Nitrogen		73.16	73.20	73.34
Oxygen		12.27	12.41	12.80
Carbon Dioxide		3.78	3.72	3.54
Water		9.92	9.80	9.45

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	50
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Sulfur Emissions Based On 0.0002 WT% Sulfur Content in the Fuel.

IPS- 90973 version code- 2 . 0 . 1 Opt: 9 72410996
HENRYCO 01/28/2000 17:56FPL Martin gas BL LOAD rge 95

FPL Martin Plant Gas fuel with Steam Power Augmentation
Augmentation only permitted above 59 degF
ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	BASE
Ambient Temp.	Deg F.	35.	95.
Ambient Relative Humid.	%	20.0	50.0
Fuel Type		Cust Gas	Cust Gas
Fuel LHV	Btu/lb	20,835	20,835
Fuel Temperature	Deg F	290	290
Output	kW	180,400.	165,100.
Heat Rate (LHV)	Btu/kWh	9,245.	9,265.
Heat Cons. (LHV) X 10^6	Btu/h	1,667.8	1,529.7
Auxiliary Power	kW	560	560
Output Net	kW	179,840.	164,540.
Heat Rate (LHV) Net	Btu/kWh	9,270.	9,300.
Exhaust Flow X 10^3	lb/h	3706.	3372.
Exhaust Temp.	Deg F.	1095.	1130.
Exhaust Heat (LHV) X 10^6	Btu/h	991.6	927.1
Steam Flow	lb/h	0.	110,260.
EMISSIONS			
NOx	ppmvd @ 15% O2	9.	12
NOx AS NO2	lb/h	61.	82
CO	ppmvd	9.	15.
CO	lb/h	30.	44.
UHC	ppmvw	7.	7.
UHC	lb/h	15.	14.
VOC	ppmvw	1.4	1.4
VOC	lb/h	3.	2.8
Particulates	lb/h	9.0	9.0
EXHAUST ANALYSIS	% VOL.		
Argon		0.90	0.83
Nitrogen		75.07	69.28
Oxygen		12.60	11.20
Carbon Dioxide		3.88	3.80
Water		7.56	14.89
SITE CONDITIONS			
Elevation	ft.	45.0	
Site Pressure	psia	14.68	
Inlet Loss	in Water	3.0	
Exhaust Loss	in Water	5.5	
Application		7FH2 Hydrogen-Cooled Generator.	
Combustion System		9/42 DLN Combustor	

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.
Sulfur Emissions Based On 0.0002 WT% Sulfur Content in the Fuel.
IPS- 90973 version code- 2 . 0 . 1 Opt: N 72410996
HENRYCO 01/24/2000 17:49FPL Martin gas BL stm aug 35_95.dat

FPL Martin Plant Gas fuel Steam Power Augmentation with Fogger at 80 degF

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE
Ambient Temp.	Deg F.	80.
Fogger Status		On
Fogger Effectiveness	%	95
Output	kW	165,000.
Heat Rate (LHV)	Btu/kWh	9,410.
Heat Cons. (LHV) X 10^6	Btu/h	1,552.7
Auxiliary Power	kW	560
Output Net	kW	164,440.
Heat Rate (LHV) Net	Btu/kWh	9,440.
Exhaust Flow X 10^3	lb/h	3444.
Exhaust Temp.	Deg F.	1125.
Exhaust Heat (LHV) X 10^6	Btu/h	933.1

EMISSIONS

NOx	ppmvd @ 15% O2	12
NOx AS NO2	lb/h	76.
CO	ppmvd	15
CO	lb/h	47.
UHC	ppmvw	7.
UHC	lb/h	14.
VOC	ppmvw	1.4
VOC	lb/h	2.8
Particulates	lb/h	9.0

EXHAUST ANALYSIS	% VOL.	
Argon		0.88
Nitrogen		73.38
Oxygen		12.19
Carbon Dioxide		3.86
Water		9.70

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Fuel Type		Cust Gas
Fuel LHV	Btu/lb	20835 @ 290 °F
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Sulfur Emissions Based On 0.0002 WT% Sulfur Content in the Fuel.

IPS- 90973 version code- 2 . 0 . 1 Opt: N 72410996

HENRYCO 01/24/2000 17:58FPL Martin gas BL stm aug 80 fogg.dat

FPL MARTIN PLANT Peak Firing

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		PEAK
Ambient Temp.	Deg F.	0.
Output	kW	196,900.
Heat Rate (LHV)	Btu/kWh	9,075.
Heat Cons. (LHV) X 10^6	Btu/h	1,786.9
Auxiliary Power	kW	560
Output Net	kW	196,340.
Heat Rate (LHV) Net	Btu/kWh	9,100.
Exhaust Flow X 10^3	lb/h	3927.
Exhaust Temp.	Deg F.	1073.
Exhaust Heat (LHV) X 10^6	Btu/h	1049.8

EMISSIONS

NOx	ppmvd @ 15% O2	15.
NOx AS NO2	lb/h	111.
CO	ppmvd	9.
CO	lb/h	32.
UHC	ppmvw	7.
UHC	lb/h	15.
VOC	ppmvw	1.4
VOC	lb/h	3.
Particulates	lb/h	9.0

EXHAUST ANALYSIS	% VOL.	
Argon		0.90
Nitrogen		75.11
Oxygen		12.45
Carbon Dioxide		3.96
Water		7.59

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	1
Fuel Type		Cust Gas
Fuel LHV	Btu/lb	20835 @ 290 °F
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Sulfur Emissions Based On 0.0002 WT% Sulfur Content in the Fuel.

IPS- 90973 version code- 2 . 0 . 1 Opt: 11 72411298
HENRYCO 01/28/2000 19:41 FPL MARTIN PLANT Peak gas 0 dry.dat

FPL MARTIN PLANT Peak Firing
ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		PEAK
Ambient Temp.	Deg F.	35.
Output	kW	190,300.
Heat Rate (LHV)	Btu/kWh	9,080.
Heat Cons. (LHV) X 10^6	Btu/h	1,727.9
Auxiliary Power	kW	560
Output Net	kW	189,740.
Heat Rate (LHV) Net	Btu/kWh	9,110.
Exhaust Flow X 10^3	lb/h	3713.
Exhaust Temp.	Deg F.	1109.
Exhaust Heat (LHV) X 10^6	Btu/h	1015.9

EMISSIONS

NOx	ppmvd @ 15% O2	15.
NOx AS NO2	lb/h	105.
CO	ppmvd	9.
CO	lb/h	30.
UHC	ppmvw	7.
UHC	lb/h	15.
VOC	ppmvw	1.4
VOC	lb/h	3.
Particulates	lb/h	9.0

EXHAUST ANALYSIS	% VOL.	
Argon		0.89
Nitrogen		75.00
Oxygen		12.39
Carbon Dioxide		3.98
Water		7.74

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	20
Fuel Type		Cust Gas
Fuel LHV	Btu/lb	20835 @ 290 °F
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Sulfur Emissions Based On 0.0002 WT% Sulfur Content in the Fuel.

IPS- 90973 version code- 2 . 0 . 1 Opt: 9 72411298
HENRYCO 01/28/2000 19:49 FPL MARTIN PLANT Peak gas 95 dry.dat

FPL MARTIN PLANT Peak Firing

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		PEAK
Ambient Temp.	Deg F.	59.
Output	kW	179,500.
Heat Rate (LHV)	Btu/kWh	9,225.
Heat Cons. (LHV) X 10^6	Btu/h	1,655.9
Auxiliary Power	kW	560
Output Net	kW	178,940.
Heat Rate (LHV) Net	Btu/kWh	9,250.
Exhaust Flow X 10^3	lb/h	3541.
Exhaust Temp.	Deg F.	1139.
Exhaust Heat (LHV) X 10^6	Btu/h	983.3

EMISSIONS

NOx	ppmvd @ 15% O2	15.
NOx AS NO2	lb/h	101.
CO	ppmvd	9.
CO	lb/h	29.
UHC	ppmvw	7.
UHC	lb/h	14.
VOC	ppmvw	1.4
VOC	lb/h	2.8
Particulates	lb/h	9.0

EXHAUST ANALYSIS	% VOL.	
Argon		0.89
Nitrogen		74.34
Oxygen		12.20
Carbon Dioxide		3.98
Water		8.59

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Fuel Type		Cust Gas
Fuel LHV	Btu/lb	20835 @ 290 °F
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Sulfur Emissions Based On 0.0002 WT% Sulfur Content in the Fuel.

IPS- 90973 version code- 2 . 0 . 1 Opt: 9 72411298
HENRYCO 01/28/2000 19:46 FPL MARTIN PLANT Peak gas 59 dry.dat

FPL MARTIN PLANT Peak Firing

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		PEAK
Ambient Temp.	Deg F.	75.
Output	kW	169,500.
Heat Rate (LHV)	Btu/kWh	9,370.
Heat Cons. (LHV) X 10^6	Btu/h	1,588.2
Auxiliary Power	kW	560
Output Net	kW	168,940.
Heat Rate (LHV) Net	Btu/kWh	9,400.
Exhaust Flow X 10^3	lb/h	3413.
Exhaust Temp.	Deg F.	1152.
Exhaust Heat (LHV) X 10^6	Btu/h	952.2
EMISSIONS		
NOx	ppmvd @ 15% O2	15.
NOx AS NO2	lb/h	97.
CO	ppmvd	9.
CO	lb/h	28.
UHC	ppmvw	7.
UHC	lb/h	14.
VOC	ppmvw	1.4
VOC	lb/h	2.8
Particulates	lb/h	9.0
EXHAUST ANALYSIS	% VOL.	
Argon		0.89
Nitrogen		73.80
Oxygen		12.12
Carbon Dioxide		3.95
Water		9.25
SITE CONDITIONS		
Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Fuel Type		Cust Gas
Fuel LHV	Btu/lb	20835 @ 290 °F
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Sulfur Emissions Based On 0.0002 WT% Sulfur Content in the Fuel.

IPS- 90973 version code- 2 . 0 . 1 Opt: 9 72411298
HENRYCO 01/28/2000 19:47 FPL MARTIN PLANT Peak gas 75 dry.dat

FPL MARTIN PLANT Peak Firing

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		PEAK
Ambient Temp.	Deg F.	95.
Output	kW	156,100.
Heat Rate (LHV)	Btu/kWh	9,595.
Heat Cons. (LHV) X 10^6	Btu/h	1,497.8
Auxiliary Power	kW	560
Output Net	kW	155,540.
Heat Rate (LHV) Net	Btu/kWh	9,630.
Exhaust Flow X 10^3	lb/h	3238.
Exhaust Temp.	Deg F.	1172.
Exhaust Heat (LHV) X 10^6	Btu/h	910.7

EMISSIONS

NOx	ppmvd @ 15% O2	15.
NOx AS NO2	lb/h	91.
CO	ppmvd	9.
CO	lb/h	26.
UHC	ppmvw	7.
UHC	lb/h	13.
VOC	ppmvw	1.4
VOC	lb/h	2.6
Particulates	lb/h	9.0

EXHAUST ANALYSIS	% VOL.	
Argon		0.88
Nitrogen		73.06
Oxygen		11.99
Carbon Dioxide		3.91
Water		10.16

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	50
Fuel Type		Cust Gas
Fuel LHV	Btu/lb	20835 @ 290 °F
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Sulfur Emissions Based On 0.0002 WT% Sulfur Content in the Fuel.

IPS- 90973 version code- 2 . 0 . 1 Opt: 9 72411298
HENRYCO 01/28/2000 19:47 FPL MARTIN PLANT Peak gas 95 dry.dat

FPL MARTIN PLANT Peak Firing

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		PEAK	PEAK	PEAK
Ambient Temp.	Deg F.	60.	70.	80.
Evap. Cooler Status		On	On	On
Evap. Cooler Effectiveness	%	95	95	95
Fuel Type		Cust Gas	Cust Gas	Cust Gas
Fuel LHV	Btu/lb	20,835	20,835	20,835
Fuel Temperature	Deg F	290	290	290
Output	kW	182,600.	177,900.	172,500.
Heat Rate (LHV)	Btu/kWh	9,190.	9,260.	9,345.
Heat Cons. (LHV) X 10^6	Btu/h	1,678.1	1,647.4	1,612.
Auxiliary Power	kW	560	560	560
Output Net	kW	182,040.	177,340.	171,940.
Heat Rate (LHV) Net	Btu/kWh	9,220.	9,290.	9,380.
Exhaust Flow X 10^3	lb/h	3581.	3513.	3441.
Exhaust Temp.	Deg F.	1131.	1141.	1149.
Exhaust Heat (LHV) X 10^6	Btu/h	994.1	980.5	964.9
EMISSIONS				
NOx	ppmvd @ 15% O2	15.	15.	15.
NOx AS NO2	lb/h	103.	100.	99.
CO	ppmvd	9.	9.	9.
CO	lb/h	29.	28.	28.
UHC	ppmvw	7.	7.	7.
UHC	lb/h	14.	14.	14.
VOC	ppmvw	1.4	1.4	1.4
VOC	lb/h	2.8	2.8	2.8
Particulates	lb/h	9.0	9.0	9.0
EXHAUST ANALYSIS	% VOL.			
Argon		0.89	0.87	0.88
Nitrogen		74.11	73.76	73.29
Oxygen		12.14	12.05	11.95
Carbon Dioxide		3.98	3.98	3.97
Water		8.88	9.34	9.91
SITE CONDITIONS				
Elevation	ft.	45.0		
Site Pressure	psia	14.68		
Inlet Loss	in Water	3.0		
Exhaust Loss	in Water	5.5		
Relative Humidity	%	60		
Application		7FH2 Hydrogen-Cooled Generator		
Combustion System		9/42 DLN Combustor		

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Sulfur Emissions Based On 0.0002 WT% Sulfur Content in the Fuel.

IPS- 90973 version code- 2 . 0 . 1 Opt: 9 72411298
HENRYCO 01/28/2000 19:57 FPL MARTIN PLANT Peak gas fogg 607080.dat

FPL MARTIN PLANT Peak Firing with FPLE Fogger on

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		PEAK	PEAK	PEAK
Ambient Temp.	Deg F.	59.	75.	95.
Ambient Relative Humid.	%	60.	60.	50.
Fogger Status		On	On	On
Fogger Effectiveness	%	95	95	95
Fuel Type		Cust Gas	Cust Gas	Cust Gas
Fuel LHV	Btu/lb	20,835	20,835	20,835
Fuel Temperature	Deg F	290	290	290
Output	kW	183,000.	175,200.	166,100.
Heat Rate (LHV)	Btu/kWh	9,185.	9,300.	9,450.
Heat Cons. (LHV) X 10^6	Btu/h	1,680.9	1,629.4	1,569.6
Auxiliary Power	kW	560	560	560
Output Net	kW	182,440.	174,640.	165,540.
Heat Rate (LHV) Net	Btu/kWh	9,210.	9,330.	9,480.
Exhaust Flow X 10^3	lb/h	3588.	3478.	3356.
Exhaust Temp.	Deg F.	1130.	1145.	1158.
Exhaust Heat (LHV) X 10^6	Btu/h	995.4	972.4	945.9
EMISSIONS				
NOx	ppmvd @ 15% O2	15.	15.	15.
NOx AS NO2	lb/h	103.	99.	96.
CO	ppmvd	9.	9.	9.
CO	lb/h	29.	28.	27.
UHC	ppmvw	7.	7.	7.
UHC	lb/h	14.	14.	13.
VOC	ppmvw	1.4	1.4	1.4
VOC	lb/h	2.8	2.8	2.6
Particulates	lb/h	9.0	9.0	9.0
EXHAUST ANALYSIS	% VOL.			
Argon		0.89	0.87	0.87
Nitrogen		74.14	73.54	72.64
Oxygen		12.15	12.01	11.81
Carbon Dioxide		3.98	3.97	3.95
Water		8.84	9.61	10.73

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Sulfur Emissions Based On 0.0002 WT% Sulfur Content in the Fuel.
IPS- 90973 version code- 2 . 0 . 1 Opt: 9 72411298
HENRYCO 01/28/2000 19:30 FPL MARTIN PLANT Peak gas fogg.dat

ATTACHMENT B

(NOTE: The vendor for the duct burner systems have not yet been selected. Table A-2A presents the natural gas duct burner emissions used in the PSD/Air Permit application. These duct burner emissions rates are representative of typical guarantees from various vendors. Following Table A-2A is information from vendors that can meet these requirements.)

Table A-2A Natural Gas Duct Burner Emissions: Full Duct Firing

Pollutant	Emission Rate (lb/MMBtu)	Heat Input (lb/MMBtu)	Emission Rate (lb/hr)
PM-10	0.01	550	5.5
NO_x	0.1	550	55.0
CO	0.08	550	44.0
VOC	0.016	550	8.8

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Custom Designed Duct Burner

PowerPlus Duct Burner

Standard Gas Fired Duct Burner

Standard Oil Fired Duct Burner

Duct Burner General Information

Aftermarket

Click on image below to download a PDF of the brochure.

Click here to order hard copies of the brochures.

PowerPlus Duct Burner

- **Engineered for the lowest emissions with "F" & "G" class turbines**
- **Optimum performance during turbine power augmentation modes.**
- **Proven field performance**

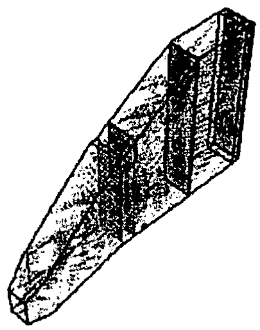
The Coen ***PowerPlus*** , built on three years of R&D and extensive field experience, introduces a new generation of duct burners to the power industry. Designed to handle the most challenging "Advanced Technology Turbines", ***PowerPlus*** provides unparalleled performance, quality, and reliability. The ***PowerPlus*** is the most reliable duct burner system in the world.

Duct Burner Design Fundamentals

Today's "Advanced Technology Turbine" has a lower O_2, and higher H_2O exhaust composition than previous gas turbine designs. This shift in exhaust temperature and composition reduces local flame temperatures and as a result has a significant impact on the duct burner stability range and CO contribution. Further, CO emission limits have been decreasing in recent years. As a result, Coen initiated a duct burner improvement program in R&D. The objectives were to identify CO formation pathways and develop reduction methods, while maintaining low NOx levels.

Through Computational Fluid Dynamics (CFD) modeling, coupled with Coen test facility experiments and field data, the following were established:

- Mixing rates and chemical kinetics were identified as the controlling factors in the modeling effort
- CO formation was identified as cooling of flame partial products with upstream turbine exhaust gas (TEG) prior to complete oxidation
- Reduction of CO, UBHC's (Unburned HydrocCarbons) and



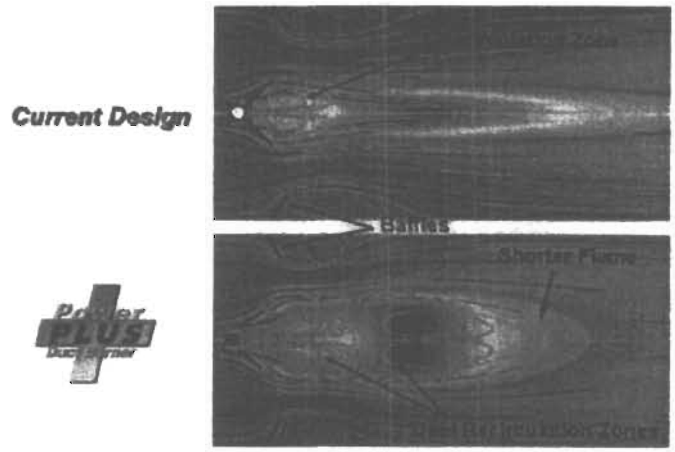
Volatile Organic Compounds (VOC's) was proven to be directly related to increasing residence time in the flame stabilizer recirculation zone and decreased mixing rates in the near field zone

- Residence time can be increased with controlled flow baffle/flame stabilizer geometry, increased with reduced TEG velocity (until buoyancy limited) and increased with reduced turbulence

Tradeoffs of the above became obvious. Simple increases in flame stabilizer size and associated recirculation size resulted in the beneficial increased residence time, but was also offset by increased TEG velocity and turbulence.& Simple bluff bodies provided excessive turbulence and mixing rates in the near field, so streamlined flame stabilizers were desired for reduced pressure drop. How to increase residence time without increases in turbulence, pressure drop or TEG velocity? Reacting CFD models indicated that it was desired to obtain a long narrow recirculation zone that minimized mixing of TEG until complete oxidation. Hundreds of configurations were modeled and analyzed.

The answer was our ***PowerPlus*** flame stabilizer arrangement. It resulted in twin recirculation zones or as we have labeled "**Dual Recirculation Technology**". This dual recirculation pattern provides for increased residence time in a narrow "corridor" without excessive blockage or undesirable flame patterns. Typical residence times with ordinary stabilizers of ***any*** shape were approximately 50 milliseconds in the recirculation zone. The ***PowerPlus*** design increases this residence time by 3 times compared to current duct burner designs. Further TEG flow is diverted to the flame ends where oxidation is nearly complete. This concept has been modeled extensively, lab tested and field confirmed. Reduction in CO emissions of approximately 50% over previous flame stabilizer designs was achieved.

Case History CO and VOC Emissions



The NOx emissions in duct burner systems are relatively low in comparison to ambient air fired burners. This is partially due to lower thermal NOx generation as a result of lower flame temperatures when firing with TEG as an oxidizer. Computational using only the extended Zeldovich mechanism, suggest that NOx emissions from duct burner systems should be lower than experimental data indicates. These computational results indicate that the ratio of prompt NOx to thermal NOx is higher in duct burner systems. A common passive method of total NOx reduction in duct burner systems is the utilization of re-burn. Re-burn is the concept of reducing incoming NOx (from the TEG) by reverse reactions from NOx to N2 in UHC rich flames. These reverse reaction rates are kinetically slow, therefore the limitation of re-burn NOx reduction is the amount of residence time in the re-burn zone. For duct burners the re-burn zone is the flame zone. Coen's ***PowerPlus*** duct burner has significant increases in residence time in the flame zone and as a consequence NOx reduction via re-burn.

The end result is our new ***PowerPlus*** duct burner. It produces the lowest NOx, CO, UBHC's and VOC emissions possible under any turbine exhaust condition!

For more information about this product, talk to your nearest Coen Sales Representative.

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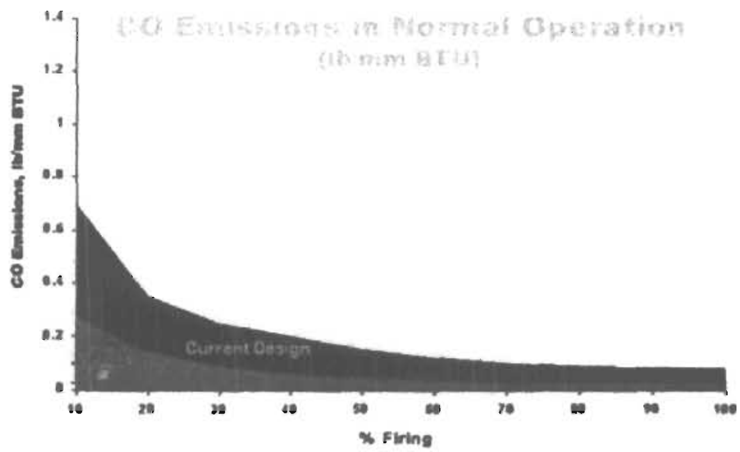
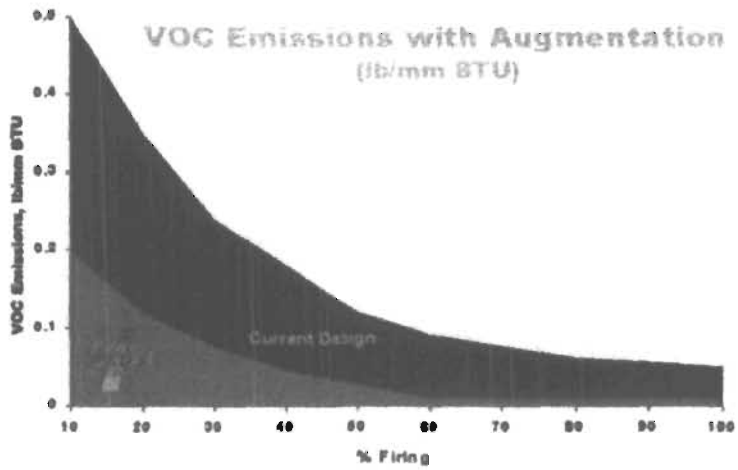
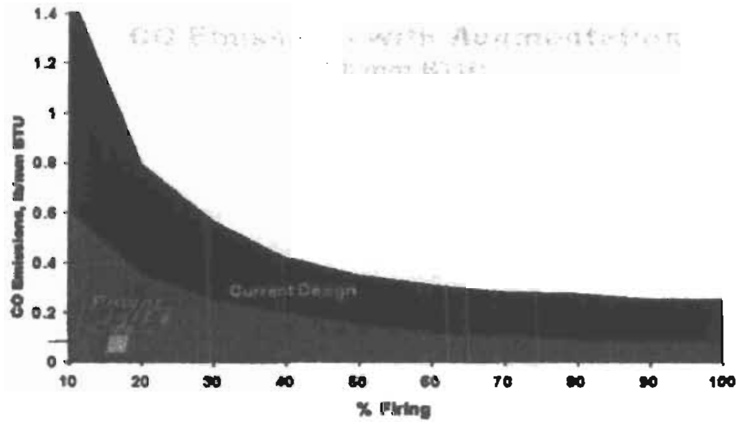
CO & VOC Emissions



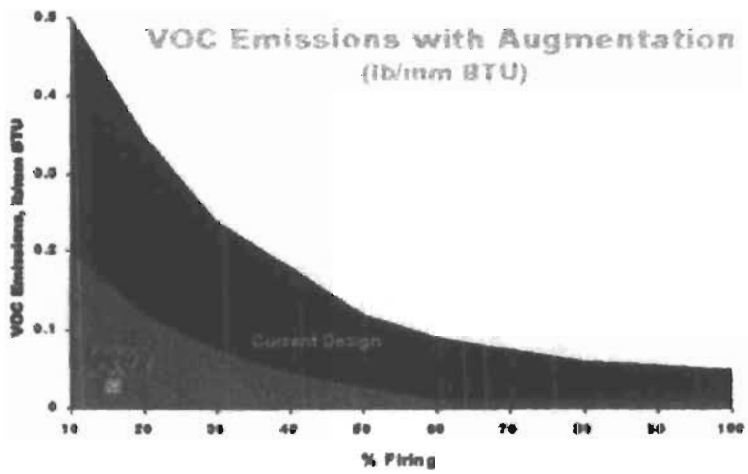
*Guaranteed Lowest Emissions ... **Under Any Condition!***



*Minimum 50% Reduction in CO and VOCs...**in any Mode!***



***No Augmenting Air!** No Increase in NOx! No **Increase** in Burner Pressure Drop!*



*Low Emissions in GT Power Augmentation Mode...**with No Supplemental Air!***

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DUCT BURNERS

ADVANTAGE DUCT BURNER

SCOPE OF SUPPLY

Horizontal (or vertical) Burner Elements (runners)
Integral Flow Baffles
ANSI B31.1 Fuel Skid with Integral PLC-based Burner Management System
Redundant Scanner Cooling Air Blowers (Skid Mounted)
Optional:

- Distribution Grids
- Pressure Reducing Stations
- Fuel Flow Measurement
- CFD and Physical Flow Modeling

APPLICATIONS

HRSG & Waste Heat Boilers
Industrial Cogeneration
Outstanding for Power Augmented GTs - can offset CO catalyst cost directly and SCR cost indirectly through GT water/steam injection
Low CO retrofits

APPLICATION SPECIFICATIONS

Duct cross sections of 3 to 50 feet
Heat inputs from 3 to 1200 MMBTU/HR
Inlet oxygen levels as low as 10.5% wet without augmenting air
Inlet H_2O as high as 20% without augmenting air
Typical TEG distribution to the burner ±25% of the avg. velocity over 90% of the cross section.

TYPICAL EMISSIONS

For most advanced gas turbine applications firing natural gas, we offer the following emission guarantees over turndown - without augmenting air:

Typical Guarantees (LB/MMBTU, HHV)

Non-Power Augmentation:

O2:	> 11.5% wet	NOx:	0.08
H2O:	< 12% wet	CO:	0.04
Burner Inlet TEG Temperature:	> 850°F	VOC:	0.004
Firing Temperatures:	> 1200°F		

Power Augmentation:

O2:	≥ 10.5% wet	NOx:	0.08
H2O:	> 12% wet	CO:	0.06
Burner Inlet TEG Temperature:	> 750°F	VOC:	0.006
Firing Temperatures:	> 1200°F		

TECHNICAL BULLETIN

PUBLICATION
#404004-03 REV 10/01

Forney Corporation
3405 Wiley Post Road
Carrollton, TX 75006 USA
Tel 972.458.6100
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www.forneycorp.com

DUCT BURNERS

ADVANTAGE DUCT BURNER

Duct Burners from Forney Corporation provide the latest designs in duct burner technology to meet the complex needs of the combined cycle and cogeneration industry. Forney Duct Burners were used in Power magazine's 2001 Power Plant of the year, Klamath Cogen's Kincaid Station.

The adVantage Duct Burner is our most advanced - state-of-the-art design for today's duct burners.

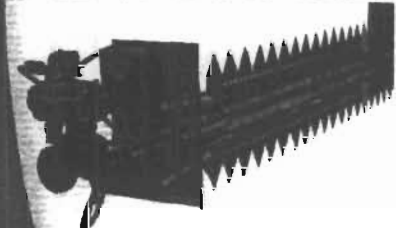
Our adVantage Duct Burner is the choice for the most demanding conditions of Advanced Gas Turbine applications. When the Turbine Exhaust Gas (TEG) inlet oxygen is low or water vapor is high, no other duct burner performs as well as Forney's adVantage.

Low inlet oxygen and high water vapor levels have typically required duct burners with augmenting air. Forney's adVantage design reduces the need for augmenting air by using an exclusive mixing process that optimizes the existing oxygen in the turbine exhaust.

The outstanding CO and VOC performance of the adVantage duct burner can help offset other plant costs such as downstream [illegible] emission reduction equipment.

Our adVantage burner is less sensitive to inlet flow distribution - meaning you get low emission performance even with wide TEG flow profiles. The adVantage duct burner also produces a shorter flame length for the same pressure drop as recirculation type burners. Shorter flame lengths require less downstream duct distance and allow a greater residence time to mix with the bulk TEG and improve temperature distribution from the burner.

ADVANTAGE



- **LOW CO AND VOC EMISSIONS** - up to 80% lower than recirculation-type burners - including over turn-down
- **LOW PRESSURE DROP & LOW NOx PERFORMANCE**- low emissions without efficiency loss
- **RELIABLE LIGHT-OFF** - High Energy Spark Ignition (HESI) for consistant performance in low oxygen and high water vapor environments
- **PATENT PENDING** design on mixing technology
- **NO AUGMENTING AIR REQUIRED** with TEG oxygen greater than 10.5% and water vapor as high as 20%
- **INVESTMENT CAST STABILIZERS** - Stainless steel stabilizers allow for long life and consistent performance
- **VORTEX SHEDDING ANALYSIS** - performed on each burner to ensure long life and trouble free operation
- **SHORT FLAME LENGTHS** - allows more mixing time to improve downstream temperature distribution

FORNEY

ATTACHMENT C

DUCT FIRING

Table A-1C Flue Gas Composition with CT and Duct Firing

lb/hr fuel (mmBtu/hr) -HHV	550	Air (lb/cf) Oxygen	(1)	0.167396	88861.4
Heating value (btu/cf)	1036	Air (lb/cf) Nitrogen	(1)	0.550712	
Fuel Flow (cf/hr)	530845.6	Prod (lb/cf) CO2	(1)	0.115072	61085.5
Fuel Flow (lb/hr)	22720.19	Prod (lb/cf) Water	(1)	0.093955	49875.6

Molecular Weight Calculation at 80 °F

Compound	Molecular Weight	Volume (Fraction)	Molecular Weight (Percent)
Argon	39.95	0.009	0.35
Nitrogen	28.01	0.734	20.56
Oxygen	32.00	0.122	3.90
Carbon Dioxide	44.01	0.039	1.70
Water	18.02	0.097	1.75
Carbon Monoxide	28.01	0	0.00
Nitrogen Dioxide	30.00	0	0.00
TOTAL		1.0001	28.25

Power Augmentation

	mass flow CT (lb/hr)	mass flow DB (lb/hr)	mass flow CT + DB (lb/hr)	volume flow (cf/hr)	(% flow)	Molecular Weight
Argon	42,849.8	0.0	42,849.8	1,254,979	0.009	0.37
Nitrogen	2,505,619.2	0.0	2,505,619.2	104,648,117	0.766	21.45
Oxygen	475,454.5	-88,861.4	386,593.0	14,135,218	0.103	3.31
Carbon Dioxide	207,066.4	61,085.5	268,151.9	7,128,730	0.052	2.30
Water	213,010.1	49,875.6	262,885.7	17,072,307	0.125	2.25
Total	3,444,000.0	22,099.6	3,466,099.6	144,239,351 acf/hr 2,403,989 acfm		29.68 MW

DUCT FIRING

Table A-1C Flue Gas Composition with CT and Duct Firing

lb/hr fuel (mmBtu/hr) -HHV	550	Air (lb/cf) Oxygen	(1)	0.167396	88861.4
Heating value (btu/cf)	1036	Air (lb/cf) Nitrogen	(1)	0.550712	
Fuel Flow (cf/hr)	530845.6	Prod (lb/cf) CO2	(1)	0.115072	61085.5
Fuel Flow (lb/hr)	22720.2	Prod (lb/cf) Water	(1)	0.093955	49875.6

Molecular Weight Calculation at 95 °F

Compound	Molecular Weight	Volume (Fraction)	Molecular Weight (Percent)
Argon	39.95	0.0088	0.35
Nitrogen	28.01	0.7316	20.49
Oxygen	32.00	0.1227	3.93
Carbon Dioxide	44.01	0.0378	1.66
Water	18.02	0.0992	1.79
Carbon Monoxide	28.01	0	0.00
Nitrogen Dioxide	30.00	0	0.00
TOTAL		1.0001	28.22

Case 1
based on Case 2 95 °F

	mass flow CT (lb/hr)	mass flow DB (lb/hr)	mass flow CT + DB (lb/hr)	volume flow (cf/hr)	(% flow)	Molecular Weight
Argon	40,568.6	0.0	40,568.6	1,188,166	0.009	0.35
Nitrogen	2,365,111.9	0.0	2,365,111.9	98,779,781	0.723	20.25
Oxygen	453,096.2	-88,861.4	364,234.8	13,317,721	0.097	3.12
Carbon Dioxide	191,979.5	61,085.5	253,065.0	6,727,649	0.049	2.17
Water	206,243.7	49,875.6	256,119.3	16,632,886	0.122	2.19
Total	3,257,000.0	22,099.6	3,279,099.6	136,646,203 acf/hr 2,277,437 acfm		28.08 MW

ATTACHMENT D

TABLES B-3A AND B-4A

Table B-3A. Capital Cost for Selective Catalytic Reduction for General Electric Frame 7F Simple Cycle Combustion Turbine

Cost Component	**Costs**		**Basis of Cost Component**
Direct Capital Costs			
SCR Associated Equipment	$2,835,000		Vendor Estimate
Ammonia Storage Tank	$136,500	$35	per 1,000 lb mass flow developed from vendor quotes
Flue Gas Ductwork	$66,758		Vatavauk,1990
Instrumentation	$50,000		Additional NOx Monitor and System
Taxes	$170,100	6%	of SCR Associated Equipment and Catalyst
Freight	$141,750	5%	of SCR Associated Equipment
Total Direct Capital Costs (TDCC)	$3,400,108		
Direct Installation Costs			
Foundation and supports	$272,009	8%	of TDCC and RCC;OAQPS Cost Control Manual
Handling & Erection	$476,015	14%	of TDCC and RCC;OAQPS Cost Control Manual
Electrical	$136,004	4%	of TDCC and RCC;OAQPS Cost Control Manual
Piping	$68,002	2%	of TDCC and RCC;OAQPS Cost Control Manual
Insulation for ductwork	$34,001	1%	of TDCC and RCC;OAQPS Cost Control Manual
Painting	$34,001	1%	of TDCC and RCC;OAQPS Cost Control Manual
Site Preparation	$5,000		Engineering Estimate
Buildings	$15,000		Engineering Estimate
Total Direct Installation Costs (TDIC)	$1,040,032		
Total Capital Costs (TCC)	$4,440,140		Sum of TDCC, TDIC and RCC
Indirect Costs			
Engineering	$444,014	10%	of Total Capital Costs; OAQPS Cost Control Manual
PSM/RMP Plan	$50,000		Engineering Estimate
Construction and Field Expense	$222,007	5%	of Total Capital Costs; OAQPS Cost Control Manual
Contractor Fees	$444,014	10%	of Total Capital Costs; OAQPS Cost Control Manual
Start-up	$88,803	2%	of Total Capital Costs; OAQPS Cost Control Manual
Performance Tests	$44,401	1%	of Total Capital Costs; OAQPS Cost Control Manual
Contingencies	$133,204	3%	of Total Capital Costs; OAQPS Cost Control Manual
Total Indirect Capital Cost (TInCC)	$1,426,444		
Total Direct, Indirect and Capital Costs (TDICC)	$5,866,584		Sum of TCC and TInCC

Table B-4A. Annualized Cost for Selective Catalytic Reduction for General Electric Frame 7F Simple Cycle Operation

Cost Component	Costs	Basis of Cost Component
Direct Annual Costs		
Operating Personnel	$18,720	24 hours/week at $15/hr
Supervision	$2,808	15% of Operating Personnel;OAQPS Cost Control Manual
Ammonia	$55,220	$300 per ton for Aqueous NH3
PSM/RMP Update	$15,000	Engineering Estimate
Inventory Cost	$71,590	Capital Recovery (10.98%) for 1/3 catalyst
Catalyst Cost	$493,000	3 years catalyst life; Based on Vendor Budget Estimate
Contingency	$19,690	3% of Direct Annual Costs
Total Direct Annual Costs (TDAC)	$676,028	
Energy Costs		
Electrical	$37,968	80kW/h for SCR & 200kW/h for cooling @ $0.04/kWh times Capacity Factor
MW Loss and Heat Rate Penalty	$207,224	0.5% of MW output; EPA, 1993 (Page 6-20)
Total Energy Costs (TEC)	$245,192	
Indirect Annual Costs		
Overhead	$46,049	60% of Operating/Supervision Labor and Ammonia
Property Taxes	$58,666	1% of Total Capital Costs
Insurance	$58,666	1% of Total Capital Costs
Annualized Total Direct Capital	$644,151	10.98% Capital Recovery Factor of 7% over 15 years times sum of TDICC
Total Indirect Annual Costs (TIAC)	$807,531	
Total Annualized Costs	$1,728,751	Sum of TDAC, TEC and TIAC
Cost Effectiveness	$13,636	NOx Reduction Only
	$25,214	Net Emission Reduction

ATTACHMENT E

(NOTE: The SCR vendor has not yet been selected. Typically the vendor is a subcontractor to the HRSG vendor since this control system is integrated into the design of the HRSG. The attached provides information on SCR and oxidation catalysts for a generic GE frame 7FA turbine in combined cycle and simple cycle. While this information is representative of system costs for comparisons with alternatives, actual system costs may be slightly higher or lower depending upon final design requirements.)

TABLE B-13. SCR, Oxidation Catalyst and $SCONO_x$ Control Equipment Costs for FPL Martin Unit 8

Operational and Cost Parameters	Value	Basis
NOx		
MW Capacity Net Gas @ 59 °F	172.44	Vendor Data
Heat Input CT Gas @ 59 °F	1,776.30	Vendor Data
Heat Rate (Btu/kW-hr)	10,301	Heat Input *10^6/MW Capacity/1000
Mass Flow CT Gas @ 59 °F	3,556,680	Vendor Data
Oxygen	12.44%	Vendor Data
Moisture	8.39%	Vendor Data
DB Heat Input	550	Vendor Data
Uncontrolled Emissions:		
NOx-Gas (lb/hr)	58.70	Vendor Data
NOx-Gas & DB (lb/hr)	113.70	Vendor Data
NOx-PA/DB or Oil (lb/hr)	319.2	Vendor Data
Controlled Emissions:		
NOx-Gas (lb/hr; 3.5 ppm)	22.83	NOx(lb/hr)*(3.5/9)
NOx-Gas & DB (lb/hr; 3.5 ppm)	33.08	NOx&DB(lb/hr)*(3.5/9)
NOx-PA/DB or Oil (lb/hr)	91.2	NOx-PA/DB(lb/hr)*(3.5/9)
NOx-Gas (lb/hr; 2.5 ppm)	16.31	NOx(lb/hr)*(2.5/9)
NOx-Gas & DB (lb/hr; 2.5 ppm)	23.63	NOx&DB(lb/hr)*(2.5/9)
NOx-PA/DB or Oil (lb/hr)	91.2	NOx-PA/DB(lb/hr)*(2.5/9)
Gas CT Only Hours	5380	Vendor Data
Gas & DB Hours	2880	Vendor Data
PA/DB or Oil Hours	500	Vendor Data
SO_2 (TPY)	68.6	Vendor Data
SCR System Cost (3.5 ppm)	$1,088,000	Engelhard Vendor Data
SCR Catalyst	$625,000	Engelhard Vendor Data
NH_3 Slip	9	Vendor Data
SCR System Cost (2.5 ppm)	$1,244,000	Estimated*
SCR Catalyst	$781,000	Estimated**
$SCONO_x$ System		
System Cost	$14,750,000	Vendor Data
Steam (lbs/hr)	17,795	Vendor Data
Gas (lb/hr)	80	Vendor Data
CO		
Uncontrolled Emissions:		
CO-Gas (lb/hr)	27.5	Vendor Data
CO-Gas & DB (lb/hr)	71.5	Vendor Data
CO-PA/DB or Oil (lb/hr)	64.7	Vendor Data
CO-Gas (ppmvd)	9	Vendor Data
CO-Gas & DB (ppmvd)	22.9	Vendor Data
CO-PA/DB or Oil (ppmvd)	20	Vendor Data
OC System Cost	$758,000	Engelhard Vendor Data
OC Catalyst	$659,000	Engelhard Vendor Data
VOC		
VOC-Gas (lb/hr)	2.74	Vendor Data
VOC-Gas & DB (lb/hr)	11.54	Vendor Data
VOC-PA/DB or Oil (lb/hr)	7.28	Vendor Data

*SCR System Cost @ 2.5 ppm = {(System Cost @ 3.5 ppm) - (Cat. Cost @ 3.5 ppm) + (Cat. Cost @ 2.5 ppm)}

** Catalyst Cost @ 2.5 ppm = {(Cat. Cost @ 3.5 ppm) - (Cat. Cost @ 4.5 ppm) + (Cat. Cost @ 3.5 ppm)}

Note: NO_x and NH_3 ppm concentrations given in ppmvd @ 15% O2, CO concentrations given in ppmvd.

TABLE B-12. Vendor Cost Data for SCR, Oxidation Catalyst and $SCONO_x$ Systems

Control Option	System Cost ($)	SCR Catalyst ($)	Turbine	Controlled Pollutant	Concentration Gas-In (ppm)	Concentration Gas-Out (ppm)	NOx Rate Oil (lb/hr)	Exhaust Mass Flow (lb/hr)	NH_3 Slip (ppm)	Pressure Drop (in H_2O)	Source	Date	$/lb/hr	$/lb/hr/%red
SCR System Cost	1,088,000.0	625,000.0	GE 7FA	NO_x	9	3.5	18.4	3,900,000	9	2.1	Engelhard	12/13/99	0.279	0.457
	463,000.0												0.160	0.262
SCR System Cost	1,249,000.0	783,000.0	GE 7FA	NO_x	9	3.5	18.4	3,900,000	5	2.4	Engelhard	12/13/99	0.320	0.524
	466,000.0												0.201	0.329
SCR System Cost	928,000.0	469,000.0	GE 7FA	NO_x	9	4.5	23.7	3,900,000	9	1.8	Engelhard	12/13/99	0.238	0.476
	459,000.0												0.120	0.197
SCR System Cost	1,088,000.0	625,000.0	GE 7FA	NO_x	9	4.5	23.7	3,900,000	5	2.1	Engelhard	12/13/99	0.279	0.558
	463,000.0												0.160	0.262
OC System Cost	758,000.0	659,000.0	GE 7FA	CO	9	0.9		3,900,000	9	2.1	Engelhard	12/13/99	0.194	0.216

	System Cost ($)	Turbine	Controlled Pollutant	Concentration Gas-In (ppm)	Concentration Gas-Out (ppm)	Natural Gas Cons. (lb/hr)	Exhaust Mass Flow (lb/hr)	Steam (lbs/hr)	Pressure Drop (in H_2O)	Source
$SCONO_x$ System	$14,750,000	GE 7FA	NO_x	9	3.5	80	3,900,000	17,795	3.4	Alstom

Note: NO_x and NH_3 ppm concentrations given in ppmvd @ 15% O2, CO concentrations given in ppmvd.

Calculations for 2.5 ppmvd					
	17.24% Cost	16.67% Increased pressure drop	61.11% Removal for 9 to 3.5 ppm		
	17.24%		72.22% Removal for 9 to 2.5 ppm		
			11.11%		
Calculations for Ammonia Slip					
	14.80%				
				Ammonia 9 to 5 Impact	
		For 2.5 ppmvd:		SCR System Catalyst	
Catalyst Increase:		$156,000			
		$781,000			
System		$463,000		$161,000	$158,000
		$1,244,000			

ENGELHARD

Golder Assoc.
Westinghouse 501D and GE 7FA - Simple and Combined Cycle
CAMET® CO Oxidation Catalyst System
VNX™ / ZNX™ SCR Catalyst System
Engelhard Budgetary Proposal EPB99639
December 13, 1999

GE 7FA – Simple Cycle

ASSUMED AMBIENT	59	59	59	59
GIVEN TURBINE EXHAUST TEMPERATURE, F	1,100	1,100	1,100	1,100
GIVEN TURBINE EXHAUST FLOW, lb/hr	3,900,000	4,080,000	3,900,000	4,080,000
ASSUMED TURBINE EXHAUST GAS ANALYSIS, % VOL. N2	75.23	71.63	75.23	71.63
O2	12.61	11.04	12.61	11.04
CO2	3.63	5.20	3.63	5.20
H2O	7.60	11.20	7.60	11.20
Ar	0.93	0.93	0.93	0.93
AMBIENT AIR FLOW, lb/hr	332,949	348,316	332,949	348,318
TOTAL FLOW - TURBINE EXHAUST + AMBIENT - lb/hr	4,232,949	4,428,316	4,232,949	4,428,318
AMBIENT + EXHAUST GAS ANALYSIS, % VOL. N2	75.70	72.37	75.70	72.37
O2	13.09	11.64	13.09	11.64
CO2	3.35	4.80	3.35	4.80
H2O	7.01	10.33	7.01	10.33
Ar	0.86	0.86	0.86	0.86
CALCULATED AIR + GAS MOL. WT.	28.48	28.32	28.48	28.32
GIVEN: TURBINE CO, ppmvd	9.0	20.0	9.0	20.0
CALC.: TURBINE CO, lb/hr	31.9	71.7	31.9	71.7
GIVEN: TURBINE NOx, ppmvd @ 15% O_2	9.0	42.0	9.0	42.0
CALC.: TURBINE NOx, lb/hr	64.5	355.2	64.5	355.2
CALC.: CO, ppmvd @ 15% O2 - AT CATALYST FACE	7.1	13.6	7.1	13.6
CALC.: NOx, ppmvd @ 15% O2 - AT CATALYST FACE	8.8	41.0	8.8	41.0
FLUE GAS TEMP. @ SCR CATALYST, F	1,025	1,025	1,025	1,025
DESIGN REQUIREMENTS				
CO CATALYST CO CONVERSION, %	90%	90%	90%	90%
SCR CATALYST NOx OUT, ppmvd @ 15% O2	3.5	ADVISE	3.5	ADVISE
NH3 SLIP, ppmvd @ 15% O2	9	12	5	12
SCR PRESSURE DROP, 4.0"WG – Nom.				
GUARANTEED PERFORMANCE DATA				
CO CONVERSION - % Min.	90.0%	90.0%	90.0%	90.0%
CO OUT, ppmvd @ 15% O2	0.7	1.4	0.7	1.4
CO OUT, lb/hr	3.2	7.2	3.2	7.2
CO PRESSURE DROP	2.2	2.4	2.2	2.4
SCR CATALYST NOx CONVERSION, % - Min.	61.1%	61.1%	61.1%	61.1%
NOx OUT, lb/hr – Max.	25.1	138.1	25.1	138.1
NOx OUT, ppmvd@15%O2 – Max.	3.4	16.0	3.4	16.0
EXPECTED AQUEOUS NH3 (28% SOL.) FLOW, lb/hr	139	424	101	424
NH3 SLIP, ppmvd@15%O2 – Max.	9	12	5	12
SCR PRESSURE DROP, "WG - Max.	4.2	4.4	4.6	4.8
REQUIRED CROSS SECTION - INSIDE LINER - A x B, sq ft	1650.0		1650.0	
CO SYSTEM	$843,000		$843,000	
REPLACEMENT CO CATALYST MODULES	$643,000		$643,000	
SCR SYSTEM	$2,835,000		$3,046,000	
REPLACEMENT SCR CATALYST MODULES	$1,479,000		$1,690,000	

ENGELHARD

Golder Assoc.
Westinghouse 501D and GE 7FA - Simple and Combined Cycle
CAMET® CO Oxidation Catalyst System
VNX™ / ZNX™ SCR Catalyst System
Engelhard Budgetary Proposal EPB99639
December 13, 1999

GE 7FA – Combined Cycle

GIVEN / CALCULATED DATA	GE 7F	GE 7F	GE 7F	GE 7F
FUEL	NG	OIL	NG	OIL
TURBINE EXHAUST FLOW, lb/hr	3,900,000	4,080,000	3,900,000	4,080,000
TURBINE EXHAUST GAS ANALYSIS, % VOL. N2	75.23	71.63	75.23	71.63
O2	12.61	11.04	12.61	11.04
CO2	3.63	5.20	3.63	5.20
H2O	7.60	11.20	7.60	11.20
Ar	0.93	0.93	0.93	0.93
GIVEN: TURBINE CO, ppmvd	9	20	9	20
CALC.: TURBINE CO, lb/hr	31.9	71.7	31.9	71.7
CALC. TURBINE CO, ppmvd @ 15% O2	7.3	15.7	7.3	15.7
GIVEN: TURBINE NOx, ppmvd @ 15% O2	9	42	9	42
CALC.: TURBINE NOx, lb/hr	64.5	355.2	64.5	355.2
CALC. GAS MOL. WT.	28.45	28.45	28.45	28.45
FLUE GAS TEMP. @ CO and SCR CATALYST, F (+/-20)	650	650	650	650
DESIGN REQUIREMENTS				
CO CATALYST CO OUT, ppmvd @ 15% O2	0.7	1.6	0.7	1.6
SCR CATALYST NOx OUT, ppmvd @ 15% O2	3.5	ADVISE	3.5	ADVISE
NH3 SLIP, ppmvd @ 15% O2	9	12	5	12
GUARANTEED PERFORMANCE DATA				
CO CATALYST CO CONVERSION, % - Min.	90.0%	90.0%	90.0%	90.0%
CO OUT, lb/hr - Max.	3.2	7.2	3.2	7.2
CO OUT, ppmvd @ 15% O2 - Max.	0.7	1.6	0.7	1.6
CO PRESSURE DROP, "WG - Max.	1.2	1.3	1.2	1.3
SCR CATALYST NOx CONVERSION, % - Min.	61.1%	61.1%	61.1%	61.1%
NOx OUT, ppmvd @ 15% O2 - Max.	3.5	18.4	3.5	18.4
NOx OUT, lb/hr - Max.	25.1	138.1	25.1	138.1
EXPECTED AQUEOUS NH3 (28% SOL.) FLOW, lb/hr	137.1	405.2	99.3	405.2
NH3 SLIP, ppmvd @ 15% O2 - Max.	9	12	5	12
SCR PRESSURE DROP, "WG - Max.	2.0	2.1	2.2	2.4
FIT HRSG INSIDE LINER - 67 ft H x 26 ft W				
CO SYSTEM	$758,000		$758,000	
REPLACEMENT CO CATALYST MODULES	$659,000		$659,000	
SCR SYSTEM	$1,088,000		$1,249,000	
REPLACEMENT SCR CATALYST MODULES	$625,000		$783,000	

FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

March 1, 2002

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. John M. Lindsay, Plant General Manager
Florida Power and Light – Martin Plant
P.O. Box 176
Indiantown, FL 34956

Re: **Request for Additional Information**
Project No. 0850001-010-AC (PSD-FL-327)
New Combined Cycle Unit No. 8

Dear Mr. Lindsay:

On February 1, 2002, the Department received your application and sufficient fee for an air construction permit to add new combined cycle Unit 8 to the existing Martin Plant. The application is incomplete. In order to continue processing your application, the Department will need the additional information requested below. Should your response to any of the below items require new calculations, please submit the new calculations, assumptions, reference material and appropriate revised pages of the application form.

1. Equipment Description: Please verify and comment on the information in the following description of equipment:

   Combined Cycle Unit No. 8 will be a "4 on 1" unit consisting of four 170 MW gas turbines, four gas-fired heat recovery steam generators (HRSGs), and one steam turbine-electrical generator.

   Gas Turbines: Each gas turbine (Unit Nos. 8A, 8B, 8C, and 8D) includes General Electric Model PG7241(FA) combustion turbine-electrical generator set, an automated gas turbine control system, an inlet air filtration system, an evaporative inlet air cooling system, a simple cycle exhaust stack that is 80 feet tall and 22.0 feet in diameter, fuel distribution systems, and ancillary support equipment. Exhaust gases will exit the simple cycle stack at approximately 1116° F with a volumetric flow rate of approximately 2,389,500 acfm.

   Heat Recovery Steam Generators (HRSGs): During combined cycle operation, the exhaust from each gas turbine will pass through a separate gas-fired heat recovery steam generator with an exhaust stack that is 120 feet tall and 19.0 feet in diameter. Exhaust gases will exit the HRSG stack at approximately 202° F with a volumetric flow rate of approximately 1,004,000 acfm.

   Fuels and Firing Rates: The primary fuel for each gas turbine is natural gas with very low sulfur distillate oil (≤ 0.05% sulfur by weight) serving as a backup fuel on a restricted basis. At a compressor inlet air temperature of 59° F, the maximum heat input rate of each gas turbine is 1600 MMBtu (LHV) per hour when firing natural gas and 1811 MMBtu (LHV) per hour when firing distillate oil. Each HRSG is designed with duct burners having a maximum heat input of 550 MMBtu (LHV) per hour when firing natural gas.

   Generating Capacity: At a compressor inlet air temperature of 59° F and the maximum heat input rate, each gas turbine generates a nominal 172 MW of shaft-driven electricity when firing natural gas and 180 MW of shaft-driven electricity when firing distillate oil. The single steam-turbine electrical generator is rated at a capacity of 470 MW. With all four gas turbines in operation and firing all HRSG duct burners, the combined cycle system generates a nominal 1150 MW of electricity.

   Controls: Each gas turbine incorporates General Electric's dry low-NOx combustion system (2.6) to minimize the formation of NOx emissions when firing natural gas. A water injection system will be installed to minimize NOx emissions when firing distillate oil. A conventional selective catalytic reduction (SCR) system will be installed in the HRSG to further reduce NOx emissions during combined cycle operation. The efficient combustion of very low sulfur fuels at high temperatures minimizes the emissions of CO, PM/PM10, SO2 and VOC.

Continuous Monitors: Each gas turbine will be equipped with continuous emissions monitoring systems (CEMS) to measure and record NOx emissions as well as flue gas carbon dioxide content.

2. Fuel Heaters: Please describe when fuel heating is necessary. Why will the gas-fired fuel heaters operate more during the first year of operation? Why aren't the fuel heaters necessary during combined cycle operation? Is there a separate heat transfer system used during combined cycle operation?

3. Cooling Tower: Please identify the determining factors in whether or not the proposed cooling tower will be installed.

4. Fuel Oil Tanks: The application indicates that the combined capacity of both fuel tanks will be approximately 2 million gallons. Based on the maximum firing rate of 14,000 gallons per hour per gas turbine, the tanks would only provide about 36 hours of simultaneous operation of all four units. Approximately how many truckloads of oil will it take to fill the two tanks? Approximately how long will it take to empty one truckload of oil? How long will it take to refill the tanks? Are there adequate roadways to provide access for this number of trucks? Describe how oil would be delivered and transferred to the tanks when the units were in operation and were expected to fire oil for an extended period of time, such as several days.

5. Operational Restrictions Requested: Please comment on the Department's interpretation of the following restrictions requested in the application.

   a. Each gas turbine shall fire no more than 500 hours of oil per consecutive 12 months (or equivalent oil consumption at full load).

      - Because of higher emissions of nearly all pollutants when firing oil, the Department has restricted oil firing as part of its BACT determination for several recent projects. For similar projects, the Department has restricted oil firing to no more than 250 hours per year per gas turbine at full load. Please comment.

      - The Department will consider this restricted operation in terms of hours of operation or fuel consumption (gallons). Please identify the preferred restriction in these terms.

   b. Duct firing shall not exceed an equivalent of 2880 hours per year per HRSG at full capacity.

      - Please identify the requested restriction in terms of maximum hours of operation or gas consumption (million cubic feet of gas).

   c. Each gas turbine shall be limited to no more than 400 hours per consecutive 12 months of steam injection for power augmentation.

   d. Each gas turbine shall be limited to no more than 60 hours per consecutive 12 months of high temperature peaking operation.

   e. Excluding startup and shutdown, each gas turbine shall not operate below 50% of base load.

   f. Until capable of operating in combined cycle mode, each gas turbine shall operate no more than 3390 hours per consecutive 12 months.

   g. Once combined cycle operation is established, simple cycle operation of the four gas turbines shall not exceed an average of 1000 hours per consecutive 12 months. Operation of any individual gas turbine shall not exceed 3390 hours per consecutive 12 months.

   h. Please explain the requested "aggregate" limit for simple cycle operation and oil firing after the combined cycle unit begins operation.

   i. Note that all requested annual limits will be specified in terms of "consecutive 12 months".

6. Emissions

   a. Please provide General Electric's emissions data sheets for gas firing and oil firing including standard operation, power augmentation, and high temperature peaking at a compressor inlet air temperature of 59° F and 100% load.

b. Please provide the manufacturer's emissions data sheet for the duct burners. Provide supporting documents and/or calculations of the expected emission levels for the combined gas turbine exhaust and the duct burner emissions (CO, NOx, and VOC).

c. The proposed NOx BACT emission rate of 12.0 ppmvd @ 15% O_2 when firing oil in combined cycle mode is higher than recent Department permits, which have established a BACT limit of 10.0 ppmvd @ 15% O_2 for an identical gas turbine controlled by SCR. Please comment.

d. The proposed NOx BACT emission rate of 42.0 ppmvd @ 15% O_2 when firing oil in simple cycle mode is higher than recent Department permits, which have established BACT limits as low as 36.0 ppmvd @ 15% O_2 for an identical gas turbine controlled by wet injection. Please comment.

e. Please clarify the averaging period for the requested NOx limit (3-hour or 24-hour; see page 2-4 and Table 4-1).

f. General Electric has guaranteed CO emission rates of 7.4 and 14.4 ppmvd @ 15% O_2 for gas and oil firing for the Frame 7FA gas turbine. Please explain the proposed CO BACT emission rates of 9 and 20 ppmvd @ 15% O_2.

g. The requested CO BACT emission rates of 24.5 ppmvd @ 15% O_2 (gas firing with duct burning), 29.5 ppmvd @ 15% O_2 (gas firing with duct burning and power augmentation or peaking), and 20.0 ppmvd @ 15% O_2 (oil firing) do not represent current BACT levels of control for CO emissions. At these levels, the Department believes that an oxidation catalyst may be cost effective. Please comment.

h. Please provide supporting documentation that duct burning would increase CO emissions from 7.4 ppmvd @ 15% O_2 to 24.5 ppmvd @ 15% O_2 when firing natural gas. Verify that high temperature peaking would not increase CO emissions. Provide supporting documentation that duct burning with power augmentation would increase CO emissions from 24.5 ppmvd @ 15% O_2 to 29.5 ppmvd @ 15% O_2 when firing natural gas.

i. The application requests EPA Method 10 testing to demonstrate compliance with the CO standards. Based on recent PSD permits for identical units, the Department intends to require a CO CEMS. Please comment.

j. Please provide supporting documentation that duct burning would increase VOC emissions from 3.5 ppmvw to 7.0 ppmvw (when firing oil in the gas turbine).

k. The proposed visible emissions standard of 20% opacity when firing oil is inconsistent with recent Department permits for identical units, which limit opacity to 10% for all fuels. Please comment.

7. Excess Emissions: Please describe the "steam blow" process and explain why 90 days of steam blows are necessary at the beginning of operation for this project. Please describe the startup and shutdown procedures including the approximate lengths of time for each portion of the procedure (cold, warm, hot, simple cycle, and combined cycle). What are the critical parameters involved? What pollutants will be in "excess" of an emissions standard, what are the expected levels, and what will be the expected duration? Please provide supporting documentation.

8. SCR Costs

a. It appears that Tables B-3a and B-4a regarding hot SCR costs have been inadvertently omitted from the application. Please submit.

b. Based on a report prepared for the Department of Energy (Onsite Sycom, 11/99), the hot SCR costs appear to be much higher than expected. This report indicates that annualized costs for "hot SCR" for a large frame unit would be approximately 20% higher than conventional SCR. The application indicates that the annualized cost for hot SCR would be 50% more than conventional SCR. Please provide the vendor quotes for both conventional SCR and hot SCR. Also, please provide the parameters submitted to the vendor for preparation of the bid.

c. The Department disputes that hot SCR is "technically infeasible" as described in the application. Recent discussions with regulatory agencies in California indicate that such systems have been designed, installed, and are functioning properly. Please comment.

d. Page 4-12 lists four facilities with hot SCR installed on simple cycle units in the early 1990s, which had problems with catalyst deactivation. Did these facilities utilize the same high-temperature zeolite catalyst that is currently being offered by the Engelhard Corporation? Have improvements in high-temperature catalysts been made since these projects were installed? Does the exhaust gas of the GE Frame 7FA approach 1200° F frequently? Under what conditions? What is the maximum operating temperature for Engelhard's new zeolite catalyst?

e. For the purchased equipment costs identified in the Table B-3, was the catalyst included in this cost? The annualized cost table includes an "annualized catalyst cost". What methods were used to ensure that the catalyst component was not "double-counted"?

f. Please describe the calculation of the heat rate penalty in Table B-4. Does this cost include "lost revenue"? EPA guidance does not allow for the inclusion of "lost revenue" in determining control equipment costs for purposes of BACT. Please comment.

9. Catalytic Oxidation System Costs

a. Please provide the vendor quotes for the catalytic oxidation system, including the parameters submitted to the vendor for preparation of the bid.

b. For the purchased equipment costs identified in the Table B-8, was the catalyst included in this cost? The annualized cost table includes an "annualized catalyst cost". What methods were used to ensure that the catalyst component was not "double-counted"?

c. Please describe the calculation of the heat rate penalty in Table B-9. Does this cost include "lost revenue"? EPA guidance does not allow for the inclusion of "lost revenue" in determining control equipment costs for purposes of BACT. Please comment.

10. Additional Air Quality Impacts Analysis: Please submit the following information as required by Rule 62-212.400(5)(h), F.A.C.

"5. Information relating to the air quality impacts of, and the nature and extent of, all general commercial, residential, industrial and other growth which has occurred since August 7,1977, in the area the facility or modification would affect."

11. EPA/NPS Comments: When received, the Department will forward any review submitted by the EPA Region 4 office or the National Park Service for comment.

12. Questions Regarding the Air Quality Analysis: The Department will submit questions and comments regarding its review of the air quality analysis before March 20, 2002.

The Department will resume processing your application after receipt of the requested information. Rule 62-4.050(3), F.A.C. requires that all applications for a Department permit must be certified by a professional engineer registered in the State of Florida. This requirement also applies to responses to Department requests for additional information of an engineering nature. For any material changes to the application, please include a new certification statement by the authorized representative or responsible official. You are reminded that Rule 62-4.055(1), F.A.C. now requires applicants to respond to requests for information within 90 days or provide a written request for an additional period of time to submit the information.

If you have any questions regarding this matter, please call me at 850/921-9536.

Sincerely,

Jeffery F. Koerner

Jeffery F. Koerner, P.E.
New Source Review Section

AAL/jfk

cc: Mr. K. H. Simmons, FPL – Environmental Services
Mr. Willie Welch, FPL – Martin Plant
Mr. Ken Kosky, Golder Associates Inc.
Mr. Tom Tittle, SED
Mr. Gregg Worley, EPA Region 4
Mr. John Bunyak, NPS

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1. Article Addressed to:

Mr. John M. Lindsay
Plant General Manager
Florida Power & Light - Martin Plant
P. O. Box 176
Indiantown, FL 34956

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Department of Environmental Protection

Jeb Bush
Governor

Marjory Stoneman Douglas Building
3900 Commonwealth Boulevard
Tallahassee, Florida 32399-3000

David B. Struhs
Secretary

February 6, 2002

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

RE: FPL Martin Plant
1150 MW Combined Cycle Unit
DEP File No. 0850001-010-AC, PSD-FL-327

Dear Mr. Bunyak:

Enclosed for your review and comment is a PSD application submitted by Florida Power and Light to expand the electrical generating capacity of their existing Martin Power Plant in Martin County, Florida.

Your comments may be forwarded to my attention at the letterhead address or faxed to the Bureau of Air Regulation at 850/922-6979. If you have any questions, please contact Jeff Koerner, review engineer, at 850/921-9536.

Sincerely,

Patty Adams

for Al Linero, P.E.
Administrator
New Source Review Section

AAL/pa

Enclosure

Cc: J. Koerner

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

February 5, 2002

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Gregg Worley, Chief
Air, Radiation Technology Branch
Preconstruction/HAP Section
U.S. EPA – Region 4
61 Forsyth Street
Atlanta, GA 30303

Re: FPL Martin Power Plant
Description: 1150 MW Combined Cycle Unit
Project No. 0850001-010-AC (PSD-FL-327)

Dear Mr. Worley:

Enclosed for your review and comment is an application to expand the electrical generating capacity of the existing FPL Martin Power Plant. The project will create a "4 on 1" combined cycle unit with a nominal capacity of 1150 MW. It will consist of two new Frame 7 FA gas turbines (≈ 170 MW each), two existing simple cycle Frame 7FA gas turbines (≈ 170 MW each), four new gas-fired HRSGs, and a single steam-electrical generator (≈ 470 MW). FPL proposes the following standards as BACT:

- NOx: 2.5 (gas)/12 ppmvd (oil) @ 15% O_2, 24-hour CEMS average; DLN combustion, water injection and SCR;
- CO: 9 (gas)/20 (oil) @ 15% O_2, combustion design;
- PM, SO_2, and VOC: efficient combustion of clean fuels.

FPL also requests some simple cycle operation, 500 hours per year of oil firing per unit, duct firing, and power augmentation. FPL proposes slightly higher emissions standards for these alternate methods of operation. Your comments may be forwarded to my attention at the letterhead address or faxed to the Bureau of Air Regulation at 850/922-6979. If you have any questions, please contact the project engineer, Jeff Koerner, at 850/921-9536.

Sincerely,

Jeffery F. Koerner

Jeffery F. Koerner, P.E.
New Source Review Section

AAL/jfk

Enclosures

Department of
Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

February 5, 2002

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- NOx: 2.5 (gas)/12 ppmvd (oil) @ 15% O_2, 24-hour CEMS average; DLN combustion, water injection and SCR;
- CO: 9 (gas)/20 (oil) @ 15% O_2, combustion design;
- PM, SO_2, and VOC: efficient combustion of clean fuels.

FPL also requests some simple cycle operation, 500 hours per year of oil firing per unit, duct firing, and power augmentation. FPL proposes slightly higher emissions standards for these alternate methods of operation. Your comments may be forwarded to my attention at the letterhead address or faxed to the Bureau of Air Regulation at 850/922-6979. If you have any questions, please contact the project engineer, Jeff Koerner, at 850/921-9536.

Sincerely,

Jeffery F. Koerner

Jeffery F. Koerner, P.E.
New Source Review Section

AAL/jfk

Enclosures

0850001

Florida Power & Light Company, Environmental Services Dept., P.O. Box 14000, Juno Beach, FL 33408

FPL

RECEIVED

MAY 23 2003

BUREAU OF AIR REGULATION

Thursday, May 22, 2003
Jeff Koerner
Bureau of Air Regulation
Division of Air Resources Management Department of Environmental Protection
2600 Blair Stone Road, MS#5505
Tallahassee, FL 32399-2400

Dear Mr. Koerner,

In preparation for the Martin Plant expansion it was determined that the existing simple cycle CTG Stacks for Units 8A and 8B would need to be extended to provide additional personal protection during the construction of the Heat Recovery Steam Generator (HRSG) for these units. The height of each stack will be extended by 40 ft to provide an emission point above the height of the HRSG's being constructed. No changes are being made to the stack diameter, the location of the Continuous Emission Monitoring System (CEMS) sample locations, or the stack test sampling locations.

As a result of these changes to Units 8A and 8B , the attached administrative corrections are being provided for the facility's Title V Operating Permit to be made in the facility's Title V Operating Permit Emission Unit Description. It has been determined that these changes will have no effect on the certification of the CEMS system, do not change the operating modes, and do not cause an increase in emissions from the facility. FPL understands that no changes are required for either the Air Construction Permit or the emission limits of the Title V Operating Permit as a result of the extension of the stack heights on Units 8A & 8B.

Should you have any questions, or need any additional information, please contact me at your earliest convenience.

Sincerely,

John C. Hampp
Sr. Regulatory Specialist
Florida Power & Light Company
JES-JB
700 Universe Blvd.
Juno Beach, FL 33408
Email: jhampp@email.fpl.com

cc: Mr. Tom Cascio,FDEP

Original permit language:

Subsection F.

E.U. ID No.	Brief Description
-011	Simple Cycle Combustion Turbine (8A)
-012	Simple Cycle Combustion Turbine (8B)

Each unit consists of a General Electric Model PG7241 (FA) combustion turbine, an electrical generator set (each designed to produce a nominal 170 MW of electrical power), an automated gas turbine control system, an inlet air filtration system, an evaporative inlet air cooling system, an exhaust stack that is 80 feet in height and 20.5 feet in diameter, and associated support equipment. Natural Gas is the primary fuel , with very low sulfur distillate oil as a limited backup fuel. Emissions of CO, PM/PM_{10} , SO2, and VOC are minimized by the efficient combustion of these clean fuels at high temperatures. NOx emissions are reduced by dry low-NOx (DLN) combustion technology during gas firing and by water injection during distillate oil firing. The units have the following CEMs installed: (a) Thermo Environmental Instruments (Model 42CHL) for NOx, and Servomex (Model 1420C) for O_2.

Proposed permit language :

Subsection F.

E.U. ID No.	Brief Description
-011	Simple Cycle Combustion Turbine (8A)
-012	Simple Cycle Combustion Turbine (8B)

Each unit consists of a General Electric Model PG7241 (FA) combustion turbine, an electrical generator set (each designed to produce a nominal 170 MW of electrical power), an automated gas turbine control system, an inlet air filtration system, an evaporative inlet air cooling system, an exhaust stack that is 120 feet in height and 20.5 feet in diameter, and associated support equipment. Natural Gas is the primary fuel, with very low sulfur distillate oil as a limited backup fuel. Emissions of CO, PM/PM_{10} , SO2, and VOC are minimized by the efficient combustion of these clean fuels at high temperatures. NOx emissions are reduced by dry low-NOx (DLN) combustion technology during gas firing and by water injection during distillate oil firing. The units have the following CEMs installed: (a) Thermo Environmental Instruments (Model 42CHL) for NOx, and Servomex (Model 1420C) for O_2.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 4
ATLANTA FEDERAL CENTER
61 FORSYTH STREET
ATLANTA, GEORGIA 30303-8960

FEB 05 2003

RECEIVED
FEB 19 2003
BUREAU OF AIR REGULATION

4APT-ATMB

Ms. Trina Vielhauer
Chief
Bureau of Air Regulation
Division of Air Resources Management
Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, Florida 23399

Dear Ms. Vielhauer:

We have received a December 5, 2002, letter from Florida Power & Light Company requesting a determination concerning the applicability of New Source Performance Standards (NSPS) Subpart Dc - "Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units." The request relates to the applicability of the standard to fuel heaters for Unit No. 8 at the Martin Power Plant and Unit No. 3 at the Manatee Power Plant. Based on our review of Subpart Dc and the information submitted to us, we have determined that the fuel heaters are not subject to Subpart Dc.

As indicated in §60.40c(a), the affected facility to which Subpart Dc applies is a steam generating unit. A "steam generating unit" is defined in §60.41c as a device that combusts any fuel and produces steam or heats water or any other heat transfer medium. The definition also indicates that the term does not include process heaters. A "process heater" is defined in the standard as a device that is primarily used to heat a material to initiate or promote a chemical reaction in which the material participates as a reactant or catalyst. A "heat transfer medium" is defined in the standard as any material that is used to transfer heat from one point to another point.

The fuel heaters which are proposed by Florida Power & Light have a heat input rate of approximately 24 million British thermal units (Btu) per hour and combust natural gas as a fuel. The heat from the combustion is used to raise the temperature of natural gas flowing through tubes. After being heated, the natural gas is routed to combustion turbines for use as fuel. Florida Power & Light has indicated that natural gas will be heated prior to being combusted in the turbines to ensure that the dry low-Nitrogen Oxides (No_x) combustion system used in the turbines operates properly.

As indicated in the definitions provided in Subpart Dc, a heat transfer medium must transfer heat from one point to another point in order for a combustion unit to be considered a steam generating unit affected facility. The only material which could be considered a heat transfer medium in the fuel heaters described by Florida Power & Light would be the natural gas which is being heated. However, the natural gas is not being heated for the purpose of transferring heat from one point to another. Since the natural gas is being heated prior to its use as a fuel, it is considered to be a reactant in a chemical reaction (i.e., combustion). As such, the fuel heaters would be considered process heaters. Since process heaters are exempt from regulation under Subpart Dc, the fuel heaters proposed by Florida Power & Light are not affected facilities.

This determination has been provided with assistance from the United States Environmental Protection Agency's Office of Enforcement and Compliance Assurance (OECA). If there are any questions regarding this letter, please contact Keith Goff of the EPA Region 4 staff at (404) 562-9137.

Sincerely,

Jim Bartlett for

Beverly H. Banister
Director
Air, Pesticides, and Toxics
Management Division

cc: Greg Fried, OECA

Florida Power & Light Company, Environmental Services Dept., P.O. Box 14000, Juno Beach, FL 33408

FPL

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DEC 11 2002
BUREAU OF AIR REGULATION

December 5, 2002

Trina Vielhauer, Chief
Bureau of Air Regulation
Division of Air Resources Management
Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 23399

RE: Martin and Manatee Power Plants
PSD Permit Nos. PSD-FL-327 and PSD-FL-328
NSPS Applicability to Gas Heaters

Dear Ms. Vielhauer:

We respectfully request a formal determination as to whether Subpart Dc of the New Source Performance Standards under 40 CFR 60 applies to the direct-fired fuel heaters proposed for Unit No. 8 at the Martin Power Plant and Unit No. 3 at the Manatee Power Plant. In connection with the draft PSD permits referenced above, the Department has suggested that Subpart Dc would apply to the installation of such heaters. We do not believe that Subpart Dc is applicable to these units for the reasons outlined below. We understand that the Department may wish to forward this request to the U.S. Environmental Protection Agency's Region IV office.

Subpart Dc applies to each "steam generating unit" with a heat input rate of less than 100 million British thermal units (mmBtu) per hour, but more than 10 mmBtu per hour. 40 CFR 60.40c. The term "steam generating unit" is in turn defined as "a device that combusts any fuel and produces steam or heats water or any other heat transfer medium." 40 CFR 60.41c

The fuel heaters proposed for installation at our plants have a heat input rate of approximately 24 mmBtu per hour and combust natural gas as a fuel, and thus meet the first part of the test. The flames and heat from the combustion fire are used to raise the temperature of natural gas flowing through tubes to the combustion turbines. Because these direct-fired heaters do not produce steam, heat water, or heat any other "heat transfer medium," the units do not meet the second part of the applicability test.

The term "heat transfer medium" is defined as "any material used for transferring heat from one point to another point." 40 CFRF 60.41c. The proposed fuel heaters combust fuel to raise the temperature of natural gas that is passed through tubing. The natural gas is not then used as a medium for transferring heat. The tubing through which the gas flows merely constitutes a physical barrier, and is not considered a "heat transfer medium." Examples of "heat transfer mediums" include air, water, Dowtherm, glycol, or other fluids or liquids that are used to transfer heat from the combustion location to another location. The obvious example is a boiler in which water/steam constitutes the "heat transfer medium;" the steam tubing itself would not be considered to be a "heat transfer medium."

In preamble statements, the U.S. Environmental Protection Agency (EPA) further clarified that the term "steam generating unit" was intended to include devices that combusted fuel to "produce steam, heat water, or *heat other fluids which are used as heat transfer media.*" 55 Fed. Reg. 37674, 37676 (Sept. 12, 1990) (emphasis added). Further, in a subsequent applicability determination, EPA confirmed that devices which "combust fuel but do not transfer heat from the combustion gases to a heat transfer medium" are not considered steam generating units under Subpart Dc. Memorandum from EPA Office of Air Quality Planning and Standards to

EPA Regions, dated November 17, 1992. Direct-fired fuel heaters, such as the ones we propose, transfer heat directly to the natural gas and do not use a heat transfer medium to do so. Therefore, they are not "steam generating units" as defined in Subpart Dc.

Moreover, the definition of "steam generating unit" specifically excludes "process heaters," and the direct-fired fuel heaters qualify under that definition: "a device that is primarily used to heat a material to initiate or promote a chemical reaction in which the material participates as a reactant or catalyst." 40 CFR 60.41c. As stated above, the fuel heaters are used to heat natural gas, and that heated natural gas is then combusted in a combustion turbine. Combustion is a chemical reaction process where the components of natural gas (e.g., carbon and hydrogen) react with the compressed inlet air. The heating of the natural gas promotes the proper chemical reaction of natural gas in the combustion turbine's General Electric DLN (dry low nitrogen oxides) system. The heated natural gas is needed for the DLN system to operate properly (i.e., proper chemical reaction) and is therefore considered to be a reactant. Thus, the direct-fired fuel heaters should be considered as process heaters for this application.

The direct-fired fuel heaters proposed at Martin and Manatee are direct-fired heaters and do not meet the definition of a "steam generating unit." We therefore respectfully request a formal determination that NSPS Subpart Dc does not apply to these heaters.

Thank you for consideration of our request. If you have any questions, please do not hesitate to contact me at (561) 691-2216.

Sincerely,

KH Simmons

Ken Simmons
Manager of New Capacity Projects

cc: Doug Neeley, EPA Region IV
David McNeal, EPA Region IV
Keith Goff, EPA Region IV
Al Linero, DEP
Jeff Koerner, DEP
Teresa Heron, DEP

RECEIVED
AUG 14 2002
BUREAU OF AIR REGULATION

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

IN RE:
FLORIDA POWER & LIGHT CO.
MARTIN COUNTY, FLORIDA

DRAFT PERMIT NO. 0850001-010-AC (PSD-FL-327)
OGC CASE NO. ____________

________________________________/

REQUEST FOR ENLARGEMENT OF TIME

FLORIDA POWER & LIGHT CO. ("FPL"), by and through undersigned counsel, and pursuant to Florida Administrative Code Rule 62-110.106(4), hereby requests an enlargement of time, to and including October 13, 2002, in which to file a Petition for Administrative Proceedings in the above-styled matter. As good cause for granting this request, FPL states:

1. On or about July 30, 2002, FPL received from the Department of Environmental Protection ("Department") an "Intent to Issue PSD Permit" and accompanying "Draft Permit," "Technical Evaluation and Preliminary Determination" and "Draft BACT Determination" regarding a new combined cycle generating unit (Unit 8) to be located at FPL's Martin Power Plant in Martin County, Florida. The "Intent to Issue" advised that FPL has fourteen days from receipt in which to file a Petition for Administrative Proceedings on the Department's proposed action.

2. Based on FPL's initial review, the Draft Permit and related documents raise issues and contain provisions that may warrant clarification or correction. Additional time is needed to fully review these documents and to discuss these issues and provisions with Department staff. FPL intends to send a letter to the Department providing its comments on the Draft Permit in the near future.

3. Accordingly, FPL requests an extension of time through and until October 13, 2002, in which to file a Petition for Administrative Proceedings on the Department's proposed action pursuant

to Sections 120.569 and 120.57, Florida Statutes, and Rule 62-110.106(4), Florida Administrative Code.

4. This request is filed simply as a protective measure to avoid waiver of FPL's right to challenge the Draft Permit in the event a mutually agreeable resolution of the issues cannot be reached. Grant of this request will not prejudice either party, but will further their mutual interest and hopefully avoid the need to initiate formal administrative proceedings in this matter.

WHEREFORE, Florida Power & Light Co. respectfully requests that the time for filing of a Petition for Administrative Proceedings regarding the Department's Intent to Issue the above-referenced PSD Permit be formally extended to and including October 13, 2002. If the Department denies this Request, FPL respectfully requests an opportunity to file a Petition for Administrative Proceedings within ten days of such denial.

Respectfully submitted this 13TH day of August, 2002.

HOPPING GREEN & SAMS, P.A.

By: ______________________

Peter C. Cunningham
Florida Bar No. 0321907
Post Office Box 6526
Tallahassee, FL 32314
850-222-7500

Attorneys for FLORIDA POWER & LIGHT CO.

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a copy of the foregoing has been furnished to the following by U.S. Mail on this 13TH day of August, 2002:

Jeff Koerner
Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road, MS 5505
Tallahassee, FL 32399-2400

W. Douglas Beason
Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Attorney

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 4
ATLANTA FEDERAL CENTER
61 FORSYTH STREET
ATLANTA, GEORGIA 30303-8960

AUG 2 8 2002

RECEIVED

SEP 03 2002

BUREAU OF AIR REGULATION

4APT-APB

Mr. A. A. Linero, P.E.
Florida Department of Environmental Protection
Mail Station 5500
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Dear Mr. Linero:

Thank you for sending the prevention of significant deterioration preliminary determination (PSD) and draft permit for a proposed modification of the Florida Power & Light Martin Power Plant in Martin County, Florida (Air Permit No. PSD-FL-327). The project involves addition of two combined cycle combustion turbines and associated heat recovery steam generators with supplemental duct firing, a common steam-electrical generator, and other associated support equipment.

Our only comment concerns the best available control technology evaluation for nitrogen oxides (NO_x) emissions when the combustion turbines are operating in simple cycle mode. The applicant's NO_x best available control technology (BACT) evaluation for simple cycle operation only took into account the option of high-temperature (hot) selective catalytic reduction (SCR) control. Likewise, the BACT determination by the Florida Department of Environmental Protection (FDEP) also appears to have taken only hot SCR into consideration for simple cycle operation. Another option is also theoretically possible as discussed below. We request that FDEP evaluate the technical feasibility of this option and, if technically feasible, the economics, environmental impacts, and energy use aspects of this option.

The other option takes advantage of the fact that a conventional SCR system (lower temperature SCR) will be in place to control NO_x emissions during combined cycle operation. Therefore, an additional option for simple cycle NO_x emissions control would be to reduce the temperature of the exhaust gases from a combustion turbine in simple cycle mode and route the reduced-temperature exhaust gases to the conventional SCR system. One method (although not the only method) for reducing temperature in such circumstances is to inject ambient air into the exhaust gases from a combustion turbine operating in simple cycle mode. If this option is technically feasible, evaluating the cost of the option should discount any costs that would otherwise be incurred for the conventional SCR system used to control combined cycle NO_x emissions.

If you have any questions regarding this letter, please call César Zapata at (404) 562-9139.

Sincerely,

Jeaneanne M. Gettle
Acting Chief
Air Permits Section

RECEIVED
DEC 10 2002
BUREAU OF AIR REGULATION

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

IN RE:
FLORIDA POWER & LIGHT CO.
MARTIN COUNTY, FLORIDA

DRAFT PERMIT NO. 0850001-010-AC (PSD-FL-327)
OGC CASE NO. 02-1209

_______________________________________/

REQUEST FOR ADDITIONAL ENLARGEMENT OF TIME

FLORIDA POWER & LIGHT CO. ("FPL"), by and through undersigned counsel, and pursuant to Florida Administrative Code Rule 62-110.106(4), hereby requests an additional enlargement of time, to and including February 10, 2003, in which to file a Petition for Administrative Proceedings in the above-styled matter. As good cause for granting this request, FPL states:

1. On or about July 30, 2002, FPL received from the Department of Environmental Protection ("Department") an "Intent to Issue PSD Permit" and accompanying "Draft Permit," "Technical Evaluation and Preliminary Determination" and "Draft BACT Determination" regarding a new combined cycle generating unit (Unit 8) to be located at FPL's Martin Power Plant in Martin County, Florida.

2. Based on FPL's initial review, the Draft Permit and related documents raised issues and contained provisions that may warrant clarification or correction. FPL's request for an extension of time until October 13, 2002, to file a Petition for Administrative Proceedings regarding the Department's proposed action on the referenced PSD Permit was granted by order of the Department dated September 11, 2002. A second request for extension of time until December 9, 2002 was granted by order of the Department dated October 24, 2002.

3. Representatives of FPL have met and corresponded with staff of the Department's Bureau of Air Regulation regarding the PSD Permit for Unit 8. It appears that most, if not all, issues

will be resolved through these ongoing discussions.

4. Accordingly, FPL requests an additional extension of time, through and until February 6, 2003, in which to file a Petition for Administrative Proceedings on the Department's proposed action pursuant to Sections 120.569 and 120.57, Florida Statutes, and Rule 62-110.106(4), Florida Administrative Code.

5. This request is filed simply as a protective measure to avoid waiver of FPL's right to challenge the Draft Permit in the event a mutually agreeable resolution of the issues cannot be reached. Grant of this request will not prejudice either party, but will further their mutual interest and hopefully avoid the need to initiate formal administrative proceedings in this matter.

WHEREFORE, Florida Power & Light Co. respectfully requests that the time for filing of a Petition for Administrative Proceedings regarding the Department's Intent to Issue the above-referenced PSD Permit be formally extended to and including February 10, 2003. If the Department denies this Request, FPL respectfully requests an opportunity to file a Petition for Administrative Proceedings within ten days of such denial.

Respectfully submitted this 9TH day of December, 2002.

HOPPING GREEN & SAMS, P.A.

By: ______________________

Peter C. Cunningham
Florida Bar No. 0321907
Post Office Box 6526
Tallahassee, FL 32314
850-222-7500

Attorneys for FLORIDA POWER & LIGHT CO.

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a copy of the foregoing has been furnished to the following by U.S. Mail on this 9th day of December, 2002:

Jeff Koerner
Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road, MS 5505
Tallahassee, FL 32399-2400

W. Douglas Beason
Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Attorney

APPENDIX 10.1.5

PSD APPLICATIONS/PERMITS

[Note: The application requesting prevention of significant deterioration (PSD) approval for the project is contained in this appendix. Appendix 10.4.2 contains a copy of the air construction and PSD Permit for Martin Units 8A and 8B.]

AIR PERMIT APPLICATION AND PREVENTION OF SIGNIFICANT DETERIORATION ANALYSIS FOR FPL MARTIN UNIT 8 COMBINED CYCLE PROJECT MARTIN COUNTY, FLORIDA

Prepared For:
Florida Power & Light Company
700 Universe Boulevard
Juno Beach, Florida 33408

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

January 2002
0137609

DISTRIBUTION:
7 Copies - FDEP
3 Copies – FPL
2 Copies - Golder Associates

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APPLICATION FOR PERMIT

Department of Environmental Protection

Division of Air Resources Management

APPLICATION FOR AIR PERMIT - TITLE V SOURCE

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

I. APPLICATION INFORMATION

Identification of Facility

1. Facility Owner/Company Name: **Florida Power and Light Company**	
2. Site Name: **Martin Power Plant**	
3. Facility Identification Number: **0850001** [ ] Unknown	
4. Facility Location: Street Address or Other Locator: **7 miles N. Indiantown on S.R. 710** City: **Indiantown** County: **Martin** Zip Code: **34956**	
5. Relocatable Facility? [ ] Yes [**X**] No	6. Existing Permitted Facility? [**X**] Yes [ ] No

Application Contact

1. Name and Title of Application Contact: **K.H. Simmons, Manager of New Capacity Projects, Environmental Services**
2. Application Contact Mailing Address: Organization/Firm: **Florida Power and Light Company** Street Address: **700 Universe Blvd.** City: **Juno Beach** State: **FL** Zip Code: **33408**
3. Application Contact Telephone Numbers: Telephone: (**561**) **691 - 2216** Fax: (**561**) **691 - 7049**

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	2-1-02
2. Permit Number:	0850001-010-AC
3. PSD Number (if applicable):	PSD-FL-327
4. Siting Number (if applicable):	

Purpose of Application

Air Operation Permit Application

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

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

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

Current construction permit number: ______________________

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

Current construction permit number: ______________________

Operation permit number to be revised: ______________________

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

Operation permit number to be revised/corrected: ______________________

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

Operation permit number to be revised: ______________________

Reason for revision: ______________________

Air Construction Permit Application

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

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

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

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

Owner/Authorized Representative or Responsible Official

1.	Name and Title of Owner/Authorized Representative or Responsible Official: **John M. Lindsay, Plant General Manager**
2.	Owner/Authorized Representative or Responsible Official Mailing Address: Organization/Firm: **Florida Power and Light Company, Martin Plant** Street Address: **P.O. Box 176** City: **Indiantown** State: **FL** Zip Code: **34956**
3.	Owner/Authorized Representative or Responsible Official Telephone Numbers: Telephone: **(561) 597 - 7106** Fax: **(561) 597 - 7416**
4.	Owner/Authorized Representative or Responsible Official Statement: *I, the undersigned, am the owner or authorized representative*(check here [ ], if so) or the responsible official (check here [✓], if so) of the Title V source addressed in this application, whichever is applicable. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof. I understand that a permit, if granted by the Department, cannot be transferred without authorization from the Department, and I will promptly notify the Department upon sale or legal transfer of any permitted emissions unit.* JM Lindsay Signature Date 1/29/02

* Attach letter of authorization if not currently on file.

Professional Engineer Certification

1.	Professional Engineer Name: **Kennard F. Kosky** Registration Number: **14996**
2.	Professional Engineer Mailing Address: Organization/Firm: **Golder Associates Inc.** Street Address: **6241 NW 23rd Street, Suite 500** City: **Gainesville** State: **FL** Zip Code: **32653-1500**
3.	Professional Engineer Telephone Numbers: Telephone: **(352) 336 - 5600** Fax: **(352) 336 - 6603**

4. Professional Engineer Statement:

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

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

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

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

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

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

Bernard F. Kortz 1/31/02

Signature Date

(seal)

* Attach any exception to certification statement.

Scope of Application

Emissions Unit ID	Description of Emissions Unit	Permit Type	Processing Fee
8A	GE Frame 7FA Combustion Turbine	AC1A	
8B	GE Frame 7FA Combustion Turbine	AC1A	
8C	GE Frame 7FA Combustion Turbine	AC1A	
8D	GE Frame 7FA Combustion Turbine	AC1A	
--	Natural Gas Heaters	AC1A	
--	Cooling Tower	AC1A	

Application Processing Fee

Check one: [ ] Attached - Amount: $: ____________ [X] Not Applicable

Construction/Modification Information

1. Description of Proposed Project or Alterations: **Construction of 2 170-MW GE FRAME 7FA combined cycle combustion turbines (CT), 4 heat recovery steam generators (HRSGs) and one steam turbine with associated electric generator (see PSD Report).**
2. Projected or Actual Date of Commencement of Construction: **May 2003**
3. Projected Date of Completion of Construction: **December 2005**

Application Comment

See PSD Report. Application fee not applicable since review is site certification review, which has an applicable fee.

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates: Zone: **17**	East (km): **543.1**	North (km): **2992.9**	
2. Facility Latitude/Longitude: Latitude (DD/MM/SS): **27 / 3 / 13**		Longitude (DD/MM/SS): **80 / 33 / 46**	
3. Governmental Facility Code: **0**	4. Facility Status Code: **A**	5. Facility Major Group SIC Code: **49**	6. Facility SIC(s): **4911**
7. Facility Comment (limit to 500 characters): **Project consists of two 170-MW dual-fuel, General Electric Frame 7FA CT/HRSGs that will use dry low-nitrogen oxide combustion technology when firing natural gas and water injection when firing distillate fuel oil, along with selective catalytic reduction (SCR) when in combined cycle mode. Each CT/HRSG will operate up to 8,760 hours per year. Current facility Title V Permit No. 0850001-004-AV.**			

Facility Contact

1. Name and Title of Facility Contact: **Willie Welch, Environmental Specialist**			
2. Facility Contact Mailing Address: Organization/Firm: **Florida Power and Light Company** Street Address: **P.O. Box 176** City: **Indiantown**	State: **FL**	Zip Code: **34956**	
3. Facility Contact Telephone Numbers: Telephone: (**561**) **597 - 7211**	Fax: (**561**) **597 - 7416**		

Facility Regulatory Classifications

Check all that apply:

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

List of Applicable Regulations

See Attachment PMR8-EU1-D.	

B. FACILITY POLLUTANTS

List of Pollutants Emitted

1. Pollutant Emitted	2. Pollutant Classif.	3. Requested Emissions Cap lb/hour	tons/year	4. Basis for Emissions Cap	5. Pollutant Comment
PM	**A**				**Particulate Matter-Total**
VOC	**A**				**Volatile Organic Compounds**
SO_2	**A**				**Sulfur Dioxide**
NO_x	**A**				**Nitrogen Oxides**
CO	**A**				**Carbon Monoxides**
PM_{10}	**A**				**Particulate Matter-PM_{10}**

C. FACILITY SUPPLEMENTAL INFORMATION

Supplemental Requirements

1. Area Map Showing Facility Location: [X] Attached, Document ID: PSD Report [ ] Not Applicable [ ] Waiver Requested
2. Facility Plot Plan: [X] Attached, Document ID: PSD Report [ ] Not Applicable [ ] Waiver Requested
3. Process Flow Diagram(s): [X] Attached, Document ID: PSD Report [ ] Not Applicable [ ] Waiver Requested
4. Precautions to Prevent Emissions of Unconfined Particulate Matter: [ ] Attached, Document ID: ______ [X] Not Applicable [ ] Waiver Requested
5. Fugitive Emissions Identification: [ ] Attached, Document ID: ______ [X] Not Applicable [ ] Waiver Requested
6. Supplemental Information for Construction Permit Application: [X] Attached, Document ID: PSD Report [ ] Not Applicable
7. Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

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

III. EMISSIONS UNIT INFORMATION

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

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

Emissions Unit Description and Status

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

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

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

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

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

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

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

3. Description of Emissions Unit Addressed in This Section (limit to 60 characters):
GE Frame 7FA CT/HRSG. Designated as Unit 8A. The CT is an existing emission unit.

4. Emissions Unit Identification Number: [ ] No ID
ID: [X] ID Unknown

5. Emissions Unit Status Code:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
C		**49**	[X]

9. Emissions Unit Comment: (Limit to 500 Characters)

This emission unit is a GE Frame 7FA CT/HRSG operating in simple and combined cycle mode (see PSD Report).

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method):

   Natural Gas Firing
   - Simple Cycle - Dry Low NO_X combustion
   - Combined Cycle - SCR

   Distillate Fuel Oil Firing
   - Water Injection
   - Combined Cycle - SCR

2. Control Device or Method Code(s): **25, 28, 65**

Emissions Unit Details

1. Package Unit:
   Manufacturer: **General Electric** Model Number: **7FA**
2. Generator Nameplate Rating: **172** MW
3. Incinerator Information:
   Dwell Temperature: °F
   Dwell Time: seconds
   Incinerator Afterburner Temperature: °F

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

Emissions Unit Operating Capacity and Schedule

1. Maximum Heat Input Rate:		**1,600**	mmBtu/hr
2. Maximum Incineration Rate:	lb/hr		tons/day
3. Maximum Process or Throughput Rate:			
4. Maximum Production Rate:			
5. Requested Maximum Operating Schedule:			
	hours/day		days/week
	weeks/year	**8,760**	hours/year
6. Operating Capacity/Schedule Comment (limit to 200 characters): **Maximum heat input at ISO conditions and natural gas firing (LHV); maximum for oil firing is 1,811 MMBtu/hr (ISO-LHV) and 180 MW; Higher power modes – gas is 1,680 MMBtu/hr and 182 MW. The maximum heat input for the HRSG duct burners is 550 MMBtu/hr.**			

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

See Attachment PMR8-EU1-D for operational requirements.
See PSD Report for permitting requirements.

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

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram? **See PSD Report**	2. Emission Point Type Code: **1**

3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point):

Exhausts through the HRSG stack during combined cycle operation and through the bypass stack during simple cycle operation.

4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:

5. Discharge Type Code: **V**	6. Stack Height: **HRSG-120 / Bypass-80** feet	7. Exit Diameter: **HRSG-19 / Bypass-22** feet
8. Exit Temperature: **202 / 1,116** °F	9. Actual Volumetric Flow Rate: **1,004,150 / 2,389,462** acfm	10. Water Vapor: **8.4** %

11. Maximum Dry Standard Flow Rate: **800,000** dscfm	12. Nonstack Emission Point Height: feet

13. Emission Point UTM Coordinates:

Zone: **17** East (km): **543.1** North (km): **2992.9**

14. Emission Point Comment (limit to 200 characters):

Stack parameters for ISO operating condition firing natural gas above; for oil 295 / 1,098°F and 1,193,859 / 2,735,300 ACFM; HPM 205 / 1,130°F and 1,014,759 / 2,426,858 (combined cycle / simple cycle).

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

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Distillate (No. 2) Fuel Oil**		
2. Source Classification Code (SCC): **20100101**	3. SCC Units: **1,000 gallons used**	
4. Maximum Hourly Rate: **14**	5. Maximum Annual Rate: **7,000**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.05**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **130**
10. Segment Comment (limit to 200 characters): **Million Btu per SCC Unit = 129.9 (rounded to 130). Based on 7.1 lb/gal; LHV of 18,300 Btu/lb, ISO conditions, 500 hrs/yr operation.**		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Natural Gas**		
2. Source Classification Code (SCC): **20100201**	3. SCC Units: **Million Cubic Feet**	
4. Maximum Hourly Rate: **1.68**	5. Maximum Annual Rate: **14,754**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **950**
10. Segment Comment (limit to 200 characters): **Based on 950 Btu/cf (LHV); ISO conditions and 8,760 hrs/yr operation.**		

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM			EL
SO_2			EL
NO_x	025, 028	065	EL
CO			EL
VOC			EL
PM_{10}			EL

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **37.8** lb/hour **63.4** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing, all loads. TPY see PSD Report, Section 2, Table 2-5; ISO conditions.**	

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **37.8 lb/hr**	4. Equivalent Allowable Emissions: **37.8** b/hour **63.4** tons/year
5. Method of Compliance (limit to 60 characters): **Annual stack test; EPA Methods 5 or 17; if > 400 hours**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Allowable emissions during oil firing - all loads; 500 hrs/yr. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **37.8** lb/hour **63.4** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing, all loads. TPY see PSD Report, Section 2.0, Table 2-5; ISO conditions.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **17.2 lb/hr**	4. Equivalent Allowable Emissions: **17.2** lb/hour **63.4** tons/year
5. Method of Compliance (limit to 60 characters): **VE Test < 10% opacity**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Allowable emissions during gas firing - all loads; 8,760 hrs/yr. See PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **SO_2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **103.1** lb/hour **70.0** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Emission Factor: 2 grains S per 100 CF gas; 0.05% S oil; lb/hr based on oil firing at 100% load and 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 1 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.05% Sulfur Oil**	4. Equivalent Allowable Emissions: **103.1** lb/hour **70.0** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel Sampling**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil firing max @ 35°F; 100% load; TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units -
Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: SO_2	2. Total Percent Efficiency of Control:
3. Potential Emissions: **103.1** lb/hour **70.0** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Emission Factor: 2 grains S per 100 CF gas; 0.05% S oil; lb/hr based on oil firing at 100% load and 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **See Comment**	4. Equivalent Allowable Emissions: **13.3** lb/hour **70.0** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel Sampling**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Requested allowable emissions and units: Pipeline Natural Gas. natural gas firing CT with duct firing, 1 gram/100 cf - 35°F, 100% load; TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: SO_2	2. Total Percent Efficiency of Control:
3. Potential Emissions: **103.1** lb/hour **70.0** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Emission Factor: 2 grains S per 100 CF gas; 0.05% S oil; lb/hr based on oil firing at 100% load and 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **See Comment**	4. Equivalent Allowable Emissions: **10.6** lb/hour **70.0** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel Sampling**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Requested allowable emissions and units: Pipeline Natural Gas. HPM firing, 1 gram/100 cf - 35°F, 100% load; 60 hrs/yr. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **SC-333.8 / CC-95.4** lb/hour **169.4** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 1 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **SC - 42 ppmvd, CC - 12 ppmvd**	4. Equivalent Allowable Emissions: **333.8 / 95.4** lb/hour **169.4** tons/year
5. Method of Compliance (limit to 60 characters): **CEM - 24-Hour Block Average**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Requested Allowable Emissions is at 15% O_2-100% load. Oil firing; max @ 35°F; 100% load; TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **SC-333.8 / CC-95.4** lb/hour **169.4** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **SC - 9 ppmvd, CC - 2.5 ppmvd**	4. Equivalent Allowable Emissions: **61.3 / 24.2** lb/hour **169.4** tons/year
5. Method of Compliance (limit to 60 characters): **CEM - 24-Hour Block Average**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Requested Allowable Emissions and Units is at 15% O_2-100% load. Gas firing; 35°F; 100% load; TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **SC-333.8 / CC-95.4** lb/hour **169.4** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **15 ppmvd**	4. Equivalent Allowable Emissions: **105.1** lb/hour **169.4** tons/year
5. Method of Compliance (limit to 60 characters): **CEM - 24-Hour Block Average**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Requested Allowable Emissions and Units is at 15% O_2-100% load. HPM firing; 35°F; 100% load; TPY @ 59°F, 60 hrs/yr. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units -
Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **89.0** lb/hour **205.4** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. TPY see PSD Report Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 1 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **20 ppmvd - Baseload**	4. Equivalent Allowable Emissions: **68.1** lb/hour **205.4** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 10; high load**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil firing; max @ 35°F; 100% load; TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **89.0** lb/hour **205.4** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **9 ppmvd**	4. Equivalent Allowable Emissions: **28.6** lb/hour **205.4** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 10; high and low load**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Gas firing; 35°F; 100% load; TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **89.0** lb/hour **205.4** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. Tons/yr see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **15 ppmvd**	4. Equivalent Allowable Emissions: **89.0** lb/hour **205.4** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 10; high load**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **HPM and duct firing; 80°F; 100% load; TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **11.69** lb/hour **27.6** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A. VOC emissions exclusive of background VOC concentrations.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 1 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **3.5 ppmvw**	4. Equivalent Allowable Emissions: **6.0** lb/hour **27.6** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 25A; high and low load**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil firing; max @ 35°F; 100% load; TPY see PSD Report, Section 2.0, Table 2.5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units -
Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **VOC**
2. Total Percent Efficiency of Control:
3. Potential Emissions: **11.69** lb/hour **27.6** tons/year
4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year
6. Emission Factor:
   Reference: **GE, 2000; Golder**
7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters):

   See PSD Report, Section 2.0; and Appendix A.
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):

   Lb/hr based on oil firing; 100% load; 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.

Allowable Emissions Allowable Emissions **2** of **3**

1. Basis for Allowable Emissions Code: **OTHER**
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **6.2 ppmvd, includes CT and duct burner**
4. Equivalent Allowable Emissions: **11.69** lb/hour **27.6** tons/year
5. Method of Compliance (limit to 60 characters):

   EPA Method 25A; high and low load
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):

   Additional requested allowable emissions and units: Gas firing; 35°F; 100% load; TPY see PSD Report, Section 2.0, Table 2.5; and Appendix A.

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **11.69** lb/hour **27.6** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **1.5 ppmvw**	4. Equivalent Allowable Emissions: **2.8** lb/hour **27.6** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 25A; high and low load**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Additional requested allowable emissions and units: HPM firing; 35°F; 100% load; TPY see PSD Report, Section 2.0, Table 2.5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM_{10}**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **37.8** lb/hour **63.4** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 59°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **37.8 lb/hr**	4. Equivalent Allowable Emissions: **37.8** lb/hour **63.4** tons/year
5. Method of Compliance (limit to 60 characters): **Annual stack test; EPA Method 5 or 17 if >400 hours**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Allowable emissions during oil firing - all loads; 500 hrs/yr. See PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units -
Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM_{10}**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **37.8** lb/hour **63.4** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing, all loads. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **17.2 lb/hr**	4. Equivalent Allowable Emissions: **17.2** lb/hour **63.4** tons/year
5. Method of Compliance (limit to 60 characters): **VE Test < 10% opacity**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Gas firing; all loads; 8,760 hrs/yr. See PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

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

Visible Emissions Limitation: Visible Emissions Limitation 1 of 2

1. Visible Emissions Subtype: **VE20**	2. Basis for Allowable Opacity: [**X**] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: **10** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **Annual VE Test EPA Method 9**	
5. Visible Emissions Comment (limit to 200 characters):	

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

Continuous Monitoring System: Continuous Monitor 1 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **NO_x**
3. CMS Requirement:	[**X**] Rule [ ] Other
4. Monitor Information: Manufacturer: Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): **NO_x CEM proposed to meet requirements of 40 CFR Part 75 have been installed for this unit. Information previously submitted to DEP.**	

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

Visible Emissions Limitation: Visible Emissions Limitation 2 of 2

1. Visible Emissions Subtype: **VE99**	2. Basis for Allowable Opacity: [ ] Rule [X] Other
3. Requested Allowable Opacity: Normal Conditions: % Exceptional Conditions: **100** % Maximum Period of Excess Opacity Allowed: **6** min/hour	
4. Method of Compliance: **None**	
5. Visible Emissions Comment (limit to 200 characters): **DEP Rule 62-201.700(1), Allowed for 2 hours (120 minutes) per 24 hours for start up, shutdown and malfunction.**	

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

Continuous Monitoring System: Continuous Monitor 2 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **NO_x**
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: Manufacturer: Model Number:	Serial Number:
5. Installation Date: **01 Jan 2002**	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): ***Parameter Code: WTF. Required by 40 CFR Part 60; subpart GG; 60.334.***	

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

Supplemental Requirements

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

Additional Supplemental Requirements for Title V Air Operation Permit Applications

11. Alternative Methods of Operation [ ] Attached, Document ID:________ [ ] Not Applicable
12. Alternative Modes of Operation (Emissions Trading) [ ] Attached, Document ID:________ [ ] Not Applicable
13. Identification of Additional Applicable Requirements [ ] Attached, Document ID:________ [ ] Not Applicable
14. Compliance Assurance Monitoring Plan [ ] Attached, Document ID:________ [ ] Not Applicable
15. Acid Rain Part Application (Hard-copy Required) [ ] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a)) Attached, Document ID:________ [ ] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) Attached, Document ID:________ [ ] New Unit Exemption (Form No. 62-210.900(1)(a)2.) Attached, Document ID:________ [ ] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) Attached, Document ID:________ [ ] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) Attached, Document ID:________ [ ] Phase NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) Attached, Document ID:________ [ ] Not Applicable

ATTACHMENT PMR8-EU1-D

APPLICABLE REQUIREMENTS LISTING

ATTACHMENT PMR8-EU1-D

Applicable Requirements Listing

EMISSION UNIT ID: EU1

FDEP Rules:

Air Pollution Control-General Provisions:

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

Stationary Sources-General:

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

Acid Rain:

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

Stationary Sources-Emission Standards:

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

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

62-297.310(1)	All Units (Test Runs-Mass Emission)
62-297.310(2)(b)	All Units (Operating Rate; other than CTs; no CT)
62-297.310(3)	All Units (Calculation of Emission)
62-297.310(4)(a)	All Units (Applicable Test Procedures; Sampling time)
62-297.310(4)(b)	All Units (Sample Volume)
62-297.310(4)(c)	All Units (Required Flow Rate Range-PM/H_2SO_4/F)
62-297.310(4)(d)	All Units (Calibration)
62-297.310(4)(e)	All Units (EPA Method 5-only)
62-297.310(5)	All Units (Determination of Process Variables)
62-297.310(6)(a)	All Units (Permanent Test Facilities-general)

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

Federal Rules:

NSPS Subpart GG:	
40 CFR 60.332(a)(1)	NO_x for Electric Utility CTs
40 CFR 60.332(a)(3)	NO_x for Electric Utility CTs
40 CFR 60.333	SO_2 limits
40 CFR 60.334	Monitoring of Operations (Custom Monitoring for Gas)
40 CFR 60.335	Test Methods

NSPS General Requirements:	
40 CFR 60.7(a)(1)	Notification of Construction
40 CFR 60.7(a)(2)	Notification of Initial Start-Up
40 CFR 60.7(a)(3)	Notification of Actual Start-Up
40 CFR 60.7(a)(4)	Notification and Recordkeeping (Physical/Operational Cycle)
40 CFR 60.7(a)(5)	Notification of CEM Demonstration
40 CFR 60.7(b)	Notification and Recordkeeping (startup/shutdown/malfunction)
40 CFR 60.7(c)	Notification and Recordkeeping (startup/shutdown/malfunction)
40 CFR 60.7(d)	Notification and Recordkeeping (startup/shutdown/malfunction)
40 CFR 60.7(f)	Notification and Recordkeeping (maintain records-2 yrs)
40 CFR 60.8(a)	Performance Test Requirements
40 CFR 60.8(b)	Performance Test Notification
40 CFR 60.8(c)	Performance Tests (representative conditions)
40 CFR 60.8(e)	Provide Stack Sampling Facilities
40 CFR 60.8(f)	Test Runs
40 CFR 60.11(a)	Compliance (ref. S. 60.8 or Subpart; other than opacity)
40 CFR 60.11(b)	Compliance (opacity determined EPA Method 9)
40 CFR 60.11(c)	Compliance (opacity; excludes startup/shutdown/malfunction)
40 CFR 60.11(d)	Compliance (maintain air pollution control equip.)
40 CFR 60.11(e)(2)	Compliance (opacity; ref. S. 60.8)
40 CFR 60.12	Circumvention
40 CFR 60.13(a)	Monitoring (Appendix B; Appendix F)

40 CFR 60.13(c)	Monitoring (Opacity COMS)
40 CFR 60.13(d)(1)	Monitoring (CEMS; span, drift, etc.)
40 CFR 60.13(d)(2)	Monitoring (COMS; span, system check)
40 CFR 60.13(e)	Monitoring (frequency of operation)
40 CFR 60.13(f)	Monitoring (frequency of operation)
40 CFR 60.13(h)	Monitoring (COMS; data requirements)
Acid Rain-Permits:	
40 CFR 72.9(a)	Permit Requirements
40 CFR 72.9(b)	Monitoring Requirements
40 CFR 72.9(c)(1)	SO_2 Allowances-hold allowances
40 CFR 72.9(c)(2)	SO_2 Allowances-violation
40 CFR 72.9(c)(3)(iii)	SO_2 Allowances-Phase II Units (listed)
40 CFR 72.9(c)(4)	SO_2 Allowances-allowances held in ATS
40 CFR 72.9(c)(5)	SO_2 Allowances-no deduction for 72.9(c)(1)(i)
40 CFR 72.9(d)	NO_x Requirements
40 CFR 72.9(e)	Excess Emission Requirements
40 CFR 72.9(f)	Recordkeeping and Reporting
40 CFR 72.9(g)	Liability
40 CFR 72.20(a)	Designated Representative; required
40 CFR 72.20(b)	Designated Representative; legally binding
40 CFR 72.20(c)	Designated Representative; certification requirements
40 CFR 72.21	Submissions
40 CFR 72.22	Alternate Designated Representative
40 CFR 72.23	Changing representatives; owners
40 CFR 72.24	Certificate of representation
40 CFR 72.30(a)	Requirements to Apply (operate)
40 CFR 72.30(b)(2)	Requirements to Apply (Phase II-Complete)
40 CFR 72.30(c)	Requirements to Apply (reapply before expiration)
40 CFR 72.30(d)	Requirements to Apply (submittal requirements)
40 CFR 72.31	Information Requirements; Acid Rain Applications
40 CFR 72.32	Permit Application Shield
40 CFR 72.33(b)	Dispatch System ID; unit/system ID
40 CFR 72.33(c)	Dispatch System ID; ID requirements
40 CFR 72.33(d)	Dispatch System ID; ID change
40 CFR 72.40(a)	General; compliance plan
40 CFR 72.40(b)	General; multi-unit compliance options
40 CFR 72.40(c)	General; conditional approval
40 CFR 72.40(d)	General; termination of compliance options
40 CFR 72.51	Permit Shield
40 CFR 72.90	Annual Compliance Certification
Allowances:	
40 CFR 73.33(a),(c)	Authorized account representative
40 CFR 73.35(c)(1)	Compliance: ID of allowances by serial number
Monitoring Part 75:	
40 CFR 75.4	Compliance Dates;

40 CFR 75.5	Prohibitions
40 CFR 75.10(a)(1)	Primary Measurement; SO_2;
40 CFR 75.10(a)(2)	Primary Measurement; NO_x;
40 CFR 75.10(a)(3)(iii)	Primary Measurement; CO_2; O_2 monitor
40 CFR 75.10(b)	Primary Measurement; Performance Requirements
40 CFR 75.10(c)	Primary Measurement; Heat Input; Appendix F
40 CFR 75.10(e)	Primary Measurement; Optional Backup Monitor
40 CFR 75.10(f)	Primary Measurement; Minimum Measurement
40 CFR 75.10(g)	Primary Measurement; Minimum Recording
40 CFR 75.11(d)	SO_2 Monitoring; Gas- and Oil-fired units
40 CFR 75.11(e)	SO_2 Monitoring; Gaseous firing
40 CFR 75.12(a)	NO_x Monitoring; Coal; Non-peaking oil/gas units
40 CFR 75.12(b)	NO_x Monitoring; Determination of NO_x emission rate; Appendix F
40 CFR 75.13(b)	CO_2 Monitoring; Appendix G
40 CFR 75.13(c)	CO_2 Monitoring; Appendix F
40 CFR 75.14(c)	Opacity Monitoring; Gas units; exemption
40 CFR 75.20(a)	Initial Certification Approval Process; Loss of Certification
40 CFR 75.20(b)	Recertification Procedures (if recertification necessary)
40 CFR 75.20(c)	Certification Procedures (if recertification necessary)
40 CFR 75.20(d)	Recertification Backup/portable monitor
40 CFR 75.20(f)	Alternate Monitoring system
40 CFR 75.21(a)	QA/QC; CEMS; Appendix B (Suspended 7/17/95-12/31/96)
40 CFR 75.21(c)	QA/QC; Calibration Gases
40 CFR 75.21(d)	QA/QC; Notification of RATA
40 CFR 75.21(e)	QA/QC; Audits
40 CFR 75.21(f)	QA/QC; CEMS (Effective 7/17/96-12/31/96)
40 CFR 75.22	Reference Methods
40 CFR 75.24	Out-of-Control Periods; CEMS
40 CFR 75.30(a)(3)	General Missing Data Procedures; NO_x
40 CFR 75.30(a)(4)	General Missing Data Procedures; SO_2
40 CFR 75.30(b)	General Missing Data Procedures; certified backup monitor
40 CFR 75.30(c)	General Missing Data Procedures; certified backup monitor
40 CFR 75.30(d)	General Missing Data Procedures; SO_2 (optional before 1/1/97)
40 CFR 75.30(e)	General Missing Data Procedures; bypass/multiple stacks
40 CFR 75.31	Initial Missing Data Procedures (new/re-certified CMS)
40 CFR 75.32	Monitoring Data Availability for Missing Data
40 CFR 75.33	Standard Missing Data Procedures
40 CFR 75.36	Missing Data for Heat Input
40 CFR 75.40	Alternate Monitoring Systems-General
40 CFR 75.41	Alternate Monitoring Systems-Precision Criteria
40 CFR 75.42	Alternate Monitoring Systems-Reliability Criteria
40 CFR 75.43	Alternate Monitoring Systems-Accessibility Criteria
40 CFR 75.44	Alternate Monitoring Systems-Timeliness Criteria
40 CFR 75.45	Alternate Monitoring Systems-Daily QA
40 CFR 75.46	Alternate Monitoring Systems-Missing data
40 CFR 75.47	Alternate Monitoring Systems-Criteria for Class
40 CFR 75.48	Alternate Monitoring Systems-Petition
40 CFR 75.53	Monitoring Plan; revisions

40 CFR 75.54(a)	Recordkeeping-general
40 CFR 75.54(b)	Recordkeeping-operating parameter
40 CFR 75.54(c)	Recordkeeping-SO_2
40 CFR 75.54(d)	Recordkeeping- NO_x
40 CFR 75.54(e)	Recordkeeping-CO_2
40 CFR 75.54(f)	Recordkeeping-Opacity
40 CFR 75.55(c)	General Recordkeeping (Specific Situations)
40 CFR 75.55(e)	General Recordkeeping (Specific Situations)
40 CFR 75.56	Certification; QA/QC Provisions
40 CFR 75.60	Reporting Requirements-General
40 CFR 75.61	Reporting Requirements-Notification cert/recertification
40 CFR 75.62	Reporting Requirements-Monitoring Plan
40 CFR 75.63	Reporting Requirements-Certification/Recertification
40 CFR 75.64(a)	Reporting Requirements-Quarterly reports; submission
40 CFR 75.64(b)	Reporting Requirements-Quarterly reports; DR statement
40 CFR 75.64(c)	Rep. Req.; Quarterly reports; Compliance Certification
40 CFR 75.64(d)	Rep. Req.; Quarterly reports; Electronic format
40 CFR 75.66	Petitions to the Administrator (if required)
Appendix A-1	Installation and Measurement Locations
Appendix A-2.	Equipment Specifications
Appendix A-3.	Performance Specifications
Appendix A-4.	Data Handling and Acquisition Systems
Appendix A-5.	Calibration Gases
Appendix A-6.	Certification Tests and Procedures
Appendix A-7.	Calculations
Appendix B	QA/QC Procedures
Appendix C-1.	Missing Data; SO_2/ NO_x for controlled sources
Appendix C-2.	Missing Data; Load-Based Procedure; NO_x & flow
Appendix D	Optional SO_2; Oil-/gas-fired units
Appendix F	Conversion Procedures
Appendix H	Traceability Protocol

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

40 CFR 77.3	Offset Plans (future)
40 CFR 77.5(b)	Deductions of Allowances (future)
40 CFR 77.6	Excess Emissions Penalties (SO_2 and NO_x; future)

III. EMISSIONS UNIT INFORMATION

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

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

Emissions Unit Description and Status

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

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

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

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

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

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

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

3. Description of Emissions Unit Addressed in This Section (limit to 60 characters):
GE Frame 7FA CT/HRSG. Designated as Unit 8B. This is an existing emission unit.

4. Emissions Unit Identification Number: [ ] No ID
ID: [**X**] ID Unknown

5. Emissions Unit Status Code:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
C		**49**	[**X**]

9. Emissions Unit Comment: (Limit to 500 Characters)

This emission unit is a GE Frame 7FA CT/HRSG operating in simple and combined cycle mode (see PSD Report).

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method): **Natural Gas Firing** • **Simple Cycle - Dry Low NO_X combustion** • **Combined Cycle - SCR** **Distillate Fuel Oil Firing** • **Water Injection** • **Combined Cycle - SCR**
2. Control Device or Method Code(s): **25, 28, 65**

Emissions Unit Details

1. Package Unit: Manufacturer: **General Electric**	Model Number: **7FA**	
2. Generator Nameplate Rating:	**172** MW	
3. Incinerator Information:		
Dwell Temperature:		°F
Dwell Time:		seconds
Incinerator Afterburner Temperature:		°F

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

Emissions Unit Operating Capacity and Schedule

1. Maximum Heat Input Rate:			1,600	mmBtu/hr
2. Maximum Incineration Rate:		lb/hr		tons/day
3. Maximum Process or Throughput Rate:				
4. Maximum Production Rate:				
5. Requested Maximum Operating Schedule:				
		hours/day		days/week
		weeks/year	8,760	hours/year
6. Operating Capacity/Schedule Comment (limit to 200 characters):				

Maximum heat input at ISO conditions and natural gas firing (LHV); maximum for oil firing is 1,811 MMBtu/hr (ISO-LHV) and 180 MW; Higher power modes – gas is 1,680 MMBtu/hr and 182 MW. The maximum heat input for the HRSG duct burners is 550 MMBtu/hr.

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

See Attachment PMR8-EU1-D for operational requirements.
See PSD Report for permitting requirements.

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

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram? **See PSD Report**	2. Emission Point Type Code: **1**

3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point):

Exhausts through the HRSG stack during combined cycle operation and through the bypass stack during simple cycle operation.

4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:

5. Discharge Type Code: **V**	6. Stack Height: **HRSG-120 / Bypass-80** feet	7. Exit Diameter: **HRSG-19 / Bypass-22** feet
8. Exit Temperature: **202 / 1,116** °F	9. Actual Volumetric Flow Rate: **1,004,150 / 2,389,462** acfm	10. Water Vapor: **8.4** %

11. Maximum Dry Standard Flow Rate: **800,000** dscfm	12. Nonstack Emission Point Height: feet

13. Emission Point UTM Coordinates:

Zone: **17** East (km): **543.1** North (km): **2992.9**

14. Emission Point Comment (limit to 200 characters):

Stack parameters for ISO operating condition firing natural gas above; for oil 295 / 1,098°F and 1,193,859 / 2,735,300 ACFM; HPM 205 / 1,130°F and 1,014,759 / 2,426,858 (combined cycle / simple cycle).

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

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Distillate (No. 2) Fuel Oil**		
2. Source Classification Code (SCC): **20100101**	3. SCC Units: **1,000 gallons used**	
4. Maximum Hourly Rate: **14**	5. Maximum Annual Rate: **7,000**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.05**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **130**
10. Segment Comment (limit to 200 characters): **Million Btu per SCC Unit = 129.9 (rounded to 130). Based on 7.1 lb/gal; LHV of 18,300 Btu/lb, ISO conditions, 500 hrs/yr operation.**		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Natural Gas**		
2. Source Classification Code (SCC): **20100201**	3. SCC Units: **Million Cubic Feet**	
4. Maximum Hourly Rate: **1.68**	5. Maximum Annual Rate: **14,754**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **950**
10. Segment Comment (limit to 200 characters): **Based on 950 Btu/cf (LHV); ISO conditions and 8,760 hrs/yr operation.**		

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM			EL
SO_2			EL
NO_x	025, 028	065	EL
CO			EL
VOC			EL
PM_{10}			EL

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **37.8** lb/hour **63.4** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing, all loads. TPY see PSD Report, Section 2, Table 2-5; ISO conditions.**	

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **37.8 lb/hr**	4. Equivalent Allowable Emissions: **37.8** b/hour **63.4** tons/year
5. Method of Compliance (limit to 60 characters): **Annual stack test; EPA Methods 5 or 17; if > 400 hours**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Allowable emissions during oil firing - all loads; 500 hrs/yr. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **37.8** lb/hour **63.4** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing, all loads. TPY see PSD Report, Section 2.0, Table 2-5; ISO conditions.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **17.2 lb/hr**	4. Equivalent Allowable Emissions: **17.2** lb/hour **63.4** tons/year
5. Method of Compliance (limit to 60 characters): **VE Test < 10% opacity**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Allowable emissions during gas firing - all loads; 8,760 hrs/yr. See PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **SO_2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **103.1** lb/hour **70.0** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Emission Factor: 2 grains S per 100 CF gas; 0.05% S oil; lb/hr based on oil firing at 100% load and 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **See Comment**	4. Equivalent Allowable Emissions: **13.3** lb/hour **70.0** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel Sampling**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Requested allowable emissions and units: Pipeline Natural Gas. natural gas firing CT with duct firing, 1 gram/100 cf - 35°F, 100% load; TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **SO_2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **103.1** lb/hour **70.0** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Emission Factor: 2 grains S per 100 CF gas; 0.05% S oil; lb/hr based on oil firing at 100% load and 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **See Comment**	4. Equivalent Allowable Emissions: **10.6** lb/hour **92.2** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel Sampling**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Requested allowable emissions and units: Pipeline Natural Gas. HPM firing, 1 gram/100 cf - 35°F, 100% load; 60 hrs/yr. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **SO_2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **103.1** lb/hour **70.0** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Emission Factor: 2 grains S per 100 CF gas; 0.05% S oil; lb/hr based on oil firing at 100% load and 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **See Comment**	4. Equivalent Allowable Emissions: **10.6** lb/hour **70.0** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel Sampling**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Requested allowable emissions and units: Pipeline Natural Gas. HPM firing, 1 gram/100 cf - 35°F, 100% load; 60 hrs/yr. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **SC-333.8 / CC-95.4** lb/hour **169.4** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 1 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **SC - 42 ppmvd, CC - 12 ppmvd**	4. Equivalent Allowable Emissions: **333.8 / 95.4** lb/hour **169.4** tons/year
5. Method of Compliance (limit to 60 characters): **CEM - 24-Hour Block Average**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Requested Allowable Emissions is at 15% O_2-100% load. Oil firing; max @ 35°F; 100% load; TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **SC-333.8 / CC-95.4** lb/hour **169.4** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **SC - 9 ppmvd, CC - 2.5 ppmvd**	4. Equivalent Allowable Emissions: **61.3 / 24.2** lb/hour **169.4** tons/year
5. Method of Compliance (limit to 60 characters): **CEM - 24-Hour Block Average**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Requested Allowable Emissions and Units is at 15% O_2-100% load. Gas firing; 35°F; 100% load; TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **SC-333.8 / CC-95.4** lb/hour **169.4** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **15 ppmvd**	4. Equivalent Allowable Emissions: **105.1** lb/hour **169.4** tons/year
5. Method of Compliance (limit to 60 characters): **CEM - 24-Hour Block Average**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Requested Allowable Emissions and Units is at 15% O_2-100% load. HPM firing; 35°F; 100% load; TPY @ 59°F, 60 hrs/yr. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **89.0** lb/hour **205.4** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. TPY see PSD Report Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions **1** of **3**

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **20 ppmvd - Baseload**	4. Equivalent Allowable Emissions: **68.1** lb/hour **205.4** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 10; high load**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil firing; max @ 35°F; 100% load; TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units -
Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **89.0** lb/hour **205.4** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **9 ppmvd**	4. Equivalent Allowable Emissions: **28.6** lb/hour **205.4** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 10; high and low load**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Gas firing; 35°F; 100% load; TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **89.0** lb/hour **205.4** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. Tons/yr see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **15 ppmvd**	4. Equivalent Allowable Emissions: **89.0** lb/hour **205.4** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 10; high load**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **HPM and duct firing; 80°F; 100% load; TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
**(Regulated Emissions Units -
Emissions-Limited and Preconstruction Review Pollutants Only)**

Potential/Fugitive Emissions

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **11.69** lb/hour **27.6** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A. VOC emissions exclusive of background VOC concentrations.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 1 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **3.5 ppmvw**	4. Equivalent Allowable Emissions: **6.0** lb/hour **27.6** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 25A; high and low load**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil firing; max @ 35°F; 100% load; TPY see PSD Report, Section 2.0, Table 2.5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **11.69** lb/hour **27.6** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **6.2 ppmvd, includes CT and duct burner**	4. Equivalent Allowable Emissions: **11.69** lb/hour **27.6** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 25A; high and low load**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Additional requested allowable emissions and units: Gas firing; 35°F; 100% load; TPY see PSD Report, Section 2.0, Table 2.5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **11.69** lb/hour **27.6** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **1.5 ppmvw**	4. Equivalent Allowable Emissions: **2.8** lb/hour **27.6** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 25A; high and low load**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Additional requested allowable emissions and units: HPM firing; 35°F; 100% load; TPY see PSD Report, Section 2.0, Table 2.5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: PM_{10}	2. Total Percent Efficiency of Control:
3. Potential Emissions: 37.8 lb/hour 63.4 tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: GE, 2000; Golder	7. Emissions Method Code: 2
8. Calculation of Emissions (limit to 600 characters): See PSD Report, Section 2.0; and Appendix A.	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): Lb/hr based on oil firing; 100% load; 59°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.	

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 37.8 lb/hr	4. Equivalent Allowable Emissions: 37.8 lb/hour 63.4 tons/year
5. Method of Compliance (limit to 60 characters): Annual stack test; EPA Method 5 or 17 if >400 hours	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): Allowable emissions during oil firing - all loads; 500 hrs/yr. See PSD Report, Section 2.0, Table 2-5; and Appendix A.	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM_{10}**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **37.8** lb/hour **63.4** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing, all loads. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **17.2 lb/hr**	4. Equivalent Allowable Emissions: **17.2** lb/hour **63.4** tons/year
5. Method of Compliance (limit to 60 characters): **VE Test < 10% opacity**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Gas firing; all loads; 8,760 hrs/yr. See PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

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

Visible Emissions Limitation: Visible Emissions Limitation 1 of 2

1. Visible Emissions Subtype: **VE20**	2. Basis for Allowable Opacity: [X] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: 10 % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **Annual VE Test EPA Method 9**	
5. Visible Emissions Comment (limit to 200 characters):	

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

Continuous Monitoring System: Continuous Monitor 1 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **NO_x**
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): **NO_x CEM proposed to meet requirements of 40 CFR Part 75 have been installed for this unit. Information previously submitted to DEP.**	

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

Visible Emissions Limitation: Visible Emissions Limitation 2 of 2

1. Visible Emissions Subtype: **VE99**	2. Basis for Allowable Opacity: [ ] Rule [X] Other
3. Requested Allowable Opacity: Normal Conditions: % Exceptional Conditions: **100** % Maximum Period of Excess Opacity Allowed: **6** min/hour	
4. Method of Compliance: **None**	
5. Visible Emissions Comment (limit to 200 characters): **DEP Rule 62-201.700(1), Allowed for 2 hours (120 minutes) per 24 hours for start up, shutdown and malfunction.**	

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

Continuous Monitoring System: Continuous Monitor 2 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **NO_x**
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): **Parameter Code: WTF. Required by 40 CFR Part 60; subpart GG; 60.334.**	

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

Supplemental Requirements

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

Additional Supplemental Requirements for Title V Air Operation Permit Applications

11. Alternative Methods of Operation [ ] Attached, Document ID:________ [ ] Not Applicable
12. Alternative Modes of Operation (Emissions Trading) [ ] Attached, Document ID:________ [ ] Not Applicable
13. Identification of Additional Applicable Requirements [ ] Attached, Document ID:________ [ ] Not Applicable
14. Compliance Assurance Monitoring Plan [ ] Attached, Document ID:________ [ ] Not Applicable
15. Acid Rain Part Application (Hard-copy Required) [ ] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a)) Attached, Document ID:________ [ ] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) Attached, Document ID:________ [ ] New Unit Exemption (Form No. 62-210.900(1)(a)2.) Attached, Document ID:________ [ ] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) Attached, Document ID:________ [ ] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) Attached, Document ID:________ [ ] Phase NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) Attached, Document ID:________ [ ] Not Applicable

III. EMISSIONS UNIT INFORMATION

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

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

Emissions Unit Description and Status

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

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

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

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

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

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

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

3. Description of Emissions Unit Addressed in This Section (limit to 60 characters):
GE Frame 7FA CT/HRSG. Designated as Unit 8C.

4. Emissions Unit Identification Number:
ID:
[ ] No ID
[X] ID Unknown

5. Emissions Unit Status Code:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
C		**49**	[X]

9. Emissions Unit Comment: (Limit to 500 Characters)

This emission unit is a GE Frame 7FA CT/HRSG operating in simple and combined cycle mode (see PSD Report).

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method): **Natural Gas Firing** • **Simple Cycle - Dry Low NO_X combustion** • **Combined Cycle - SCR** **Distillate Fuel Oil Firing** • **Water Injection** • **Combined Cycle - SCR**	
2. Control Device or Method Code(s): **25, 28, 65**	

Emissions Unit Details

1. Package Unit: Manufacturer: **General Electric**	Model Number: **7FA**	
2. Generator Nameplate Rating:	**172** MW	
3. Incinerator Information: Dwell Temperature: Dwell Time: Incinerator Afterburner Temperature:		 °F seconds °F

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

Emissions Unit Operating Capacity and Schedule

1. Maximum Heat Input Rate:		**1,600**	mmBtu/hr
2. Maximum Incineration Rate:	lb/hr		tons/day
3. Maximum Process or Throughput Rate:			
4. Maximum Production Rate:			
5. Requested Maximum Operating Schedule:			
	hours/day		days/week
	weeks/year	**8,760**	hours/year

6. Operating Capacity/Schedule Comment (limit to 200 characters):

Maximum heat input at ISO conditions and natural gas firing (LHV); maximum for oil firing is 1,811 MMBtu/hr (ISO-LHV) and 180 MW; Higher power modes – gas is 1,680 MMBtu/hr and 182 MW. The maximum heat input for the HRSG duct burners is 550 MMBtu/hr.

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

See Attachment PMR8-EU1-D for operational requirements.
See PSD Report for permitting requirements.

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

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram? **See PSD Report**	2. Emission Point Type Code: **1**

3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point):

Exhausts through the HRSG stack during combined cycle operation and through the bypass stack during simple cycle operation.

4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:

5. Discharge Type Code: **V**	6. Stack Height: **HRSG-120 / Bypass-80** feet	7. Exit Diameter: **HRSG-19 / Bypass-22** feet
8. Exit Temperature: **202 / 1,116** °F	9. Actual Volumetric Flow Rate: **1,004,150 / 2,389,462** acfm	10. Water Vapor: **8.4** %

11. Maximum Dry Standard Flow Rate: **800,000** dscfm	12. Nonstack Emission Point Height: feet

13. Emission Point UTM Coordinates:

Zone: **17** East (km): **543.1** North (km): **2992.9**

14. Emission Point Comment (limit to 200 characters):

Stack parameters for ISO operating condition firing natural gas above; for oil 295 / 1,098°F and 1,193,859 / 2,735,300 ACFM; HPM 205 / 1,130°F and 1,014,759 / 2,426,858 (combined cycle / simple cycle).

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

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Distillate (No. 2) Fuel Oil**		
2. Source Classification Code (SCC): **20100101**	3. SCC Units: **1,000 gallons used**	
4. Maximum Hourly Rate: **14**	5. Maximum Annual Rate: **7,000**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.05**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **130**
10. Segment Comment (limit to 200 characters): **Million Btu per SCC Unit = 129.9 (rounded to 130). Based on 7.1 lb/gal; LHV of 18,300 Btu/lb, ISO conditions, 500 hrs/yr operation.**		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Natural Gas**		
2. Source Classification Code (SCC): **20100201**	3. SCC Units: **Million Cubic Feet**	
4. Maximum Hourly Rate: **1.68**	5. Maximum Annual Rate: **14,754**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **950**
10. Segment Comment (limit to 200 characters): **Based on 950 Btu/cf (LHV); ISO conditions and 8,760 hrs/yr operation.**		

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM			EL
SO_2			EL
NO_x	025, 028	065	EL
CO			EL
VOC			EL
PM_{10}			EL

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **37.8** lb/hour **63.4** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing, all loads. TPY see PSD Report, Section 2, Table 2-5; ISO conditions.**	

Allowable Emissions Allowable Emissions **1** of **2**

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **37.8 lb/hr**	4. Equivalent Allowable Emissions: **37.8** b/hour **63.4** tons/year
5. Method of Compliance (limit to 60 characters): **Annual stack test; EPA Methods 5 or 17; if > 400 hours**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Allowable emissions during oil firing - all loads; 500 hrs/yr. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **37.8** lb/hour **63.4** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing, all loads. TPY see PSD Report, Section 2.0, Table 2-5; ISO conditions.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **17.2 lb/hr**	4. Equivalent Allowable Emissions: **17.2** lb/hour **63.4** tons/year
5. Method of Compliance (limit to 60 characters): **VE Test < 10% opacity**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Allowable emissions during gas firing - all loads; 8,760 hrs/yr. See PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **SO_2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **103.1** lb/hour **70.0** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Emission Factor: 2 grains S per 100 CF gas; 0.05% S oil; lb/hr based on oil firing at 100% load and 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 1 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.05% Sulfur Oil**	4. Equivalent Allowable Emissions: **103.1** lb/hour **70.0** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel Sampling**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil firing max @ 35°F; 100% load; TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **SO_2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **103.1** lb/hour **70.0** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Emission Factor: 2 grains S per 100 CF gas; 0.05% S oil; lb/hr based on oil firing at 100% load and 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions **2** of **3**

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **See Comment**	4. Equivalent Allowable Emissions: **13.3** lb/hour **70.0** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel Sampling**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Requested allowable emissions and units: Pipeline Natural Gas. natural gas firing CT with duct firing, 1 gram/100 cf - 35°F, 100% load; TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **SO_2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **103.1** lb/hour **70.0** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Emission Factor: 2 grain S per 100 CF gas; 0.05% S oil; lb/hr based on oil firing at 100% load and 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **See Comment**	4. Equivalent Allowable Emissions: **10.6** lb/hour **70** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel Sampling**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Requested allowable emissions and units: Pipeline Natural Gas. HPM firing, 1 gram/100 cf - 35°F, 100% load; 60 hrs/yr. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **SC-333.8 / CC-95.4** lb/hour **169.4** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 1 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **SC - 42 ppmvd, CC - 12 ppmvd**	4. Equivalent Allowable Emissions: **333.8 / 95.4** lb/hour **169.4** tons/year
5. Method of Compliance (limit to 60 characters): **CEM - 24-Hour Block Average**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Requested Allowable Emissions is at 15% O_2-100% load. Oil firing; max @ 35°F; 100% load; TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **SC-333.8 / CC-95.4** lb/hour **169.4** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **SC - 9 ppmvd, CC - 2.5 ppmvd**	4. Equivalent Allowable Emissions: **61.3 / 24.2** lb/hour **169.4** tons/year
5. Method of Compliance (limit to 60 characters): **CEM - 24-Hour Block Average**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Requested Allowable Emissions and Units is at 15% O_2-100% load. Gas firing; 35°F; 100% load; TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **SC-333.8 / CC-95.4** lb/hour **169.4** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **15 ppmvd**	4. Equivalent Allowable Emissions: **105.1** lb/hour **169.4** tons/year
5. Method of Compliance (limit to 60 characters): **CEM - 24-Hour Block Average**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Requested Allowable Emissions and Units is at 15% O_2-100% load. HPM firing; 35°F; 100% load; TPY @ 59°F, 60 hrs/yr. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **89.0** lb/hour **205.4** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. TPY see PSD Report Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions **1** of **3**

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **20 ppmvd - Baseload**	4. Equivalent Allowable Emissions: **68.1** lb/hour **205.4** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 10; high load**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil firing; max @ 35°F; 100% load; TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **89.0** lb/hour **205.4** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **9 ppmvd**	4. Equivalent Allowable Emissions: **28.6** lb/hour **205.4** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 10; high and low load**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Gas firing; 35°F; 100% load; TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **89.0** lb/hour **205.4** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. Tons/yr see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **15 ppmvd**	4. Equivalent Allowable Emissions: **89.0** lb/hour **205.4** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 10; high load**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **HPM and duct firing; 80°F; 100% load; TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units -
Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **11.69** lb/hour **27.6** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A. VOC emissions exclusive of background VOC concentrations.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 1 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **3.5 ppmvw**	4. Equivalent Allowable Emissions: **6.0** lb/hour **27.6** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 25A; high and low load**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil firing; max @ 35°F; 100% load; TPY see PSD Report, Section 2.0, Table 2.5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **11.69** lb/hour **27.6** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **6.2 ppmvd, includes CT and duct burner**	4. Equivalent Allowable Emissions: **11.69** lb/hour **27.6** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 25A; high and low load**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Additional requested allowable emissions and units: Gas firing; 35°F; 100% load; TPY see PSD Report, Section 2.0, Table 2.5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units -
Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **11.69** lb/hour **27.6** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **1.5 ppmvw**	4. Equivalent Allowable Emissions: **2.8** lb/hour **27.6** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 25A; high and low load**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Additional requested allowable emissions and units: HPM firing; 35°F; 100% load; TPY see PSD Report, Section 2.0, Table 2.5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM_{10}**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **37.8** lb/hour **63.4** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 59°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions **1** of **2**

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **37.8 lb/hr**	4. Equivalent Allowable Emissions: **37.8** lb/hour **63.4** tons/year
5. Method of Compliance (limit to 60 characters): **Annual stack test; EPA Method 5 or 17 if >400 hours**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Allowable emissions during oil firing - all loads; 500 hrs/yr. See PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: PM_{10}	2. Total Percent Efficiency of Control:
3. Potential Emissions: 37.8 lb/hour 63.4 tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: GE, 2000; Golder	7. Emissions Method Code: 2
8. Calculation of Emissions (limit to 600 characters): See PSD Report, Section 2.0; and Appendix A.	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): Lb/hr based on oil firing, all loads. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 17.2 lb/hr	4. Equivalent Allowable Emissions: 17.2 lb/hour 63.4 tons/year
5. Method of Compliance (limit to 60 characters): VE Test < 10% opacity	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): Gas firing; all loads; 8,760 hrs/yr. See PSD Report, Section 2.0, Table 2-5; and Appendix A.	

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

Visible Emissions Limitation: Visible Emissions Limitation 1 of 2

1. Visible Emissions Subtype: **VE20**	2. Basis for Allowable Opacity: [X] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: 10 % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **Annual VE Test EPA Method 9**	
5. Visible Emissions Comment (limit to 200 characters):	

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

Continuous Monitoring System: Continuous Monitor 1 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **NO_x**
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: **Not yet determined** Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): **NO_x CEM proposed to meet requirements of 40 CFR Part 75 have been installed for this unit. Information previously submitted to DEP.**	

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

Visible Emissions Limitation: Visible Emissions Limitation 2 of 2

1. Visible Emissions Subtype: **VE99**	2. Basis for Allowable Opacity: [ ] Rule [X] Other
3. Requested Allowable Opacity: Normal Conditions: % Exceptional Conditions: **100** % Maximum Period of Excess Opacity Allowed: **6** min/hour	
4. Method of Compliance: **None**	
5. Visible Emissions Comment (limit to 200 characters): **DEP Rule 62-201.700(1), Allowed for 2 hours (120 minutes) per 24 hours for start up, shutdown and malfunction.**	

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

Continuous Monitoring System: Continuous Monitor 2 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **NO_x**
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: **Not yet determined** Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): **Parameter Code: WTF. Required by 40 CFR Part 60; subpart GG; 60.334.**	

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

Supplemental Requirements

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

Additional Supplemental Requirements for Title V Air Operation Permit Applications

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

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

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

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

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

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

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

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

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

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

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

    [ ] Not Applicable

III. EMISSIONS UNIT INFORMATION

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

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in This Section: (Check one) [X] This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent). [ ] This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions. [ ] This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.			
2. Regulated or Unregulated Emissions Unit? (Check one) [X] The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit. [ ] The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.			
3. Description of Emissions Unit Addressed in This Section (limit to 60 characters): **GE Frame 7FA CT/HRSG. Designated as Unit 8D.**			
4. Emissions Unit Identification Number: ID:			[ ] No ID [X] ID Unknown
5. Emissions Unit Status Code: **C**	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code: **49**	8. Acid Rain Unit? [X]
9. Emissions Unit Comment: (Limit to 500 Characters) **This emission unit is a GE Frame 7FA CT/HRSG operating in simple and combined cycle mode (see PSD Report).**			

Emissions Unit Control Equipment

1.	Control Equipment/Method Description (Limit to 200 characters per device or method): **Natural Gas Firing** • **Simple Cycle - Dry Low NO_X combustion** • **Combined Cycle - SCR** **Distillate Fuel Oil Firing** • **Water Injection** • **Combined Cycle - SCR**
2.	Control Device or Method Code(s): **25, 28, 65**

Emissions Unit Details

1.	Package Unit: Manufacturer: **General Electric**	Model Number: **7FA**
2.	Generator Nameplate Rating:	**172** MW
3.	Incinerator Information: Dwell Temperature: Dwell Time: Incinerator Afterburner Temperature:	 °F seconds °F

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

Emissions Unit Operating Capacity and Schedule

1. Maximum Heat Input Rate:			1,600	mmBtu/hr
2. Maximum Incineration Rate:		lb/hr		tons/day
3. Maximum Process or Throughput Rate:				
4. Maximum Production Rate:				
5. Requested Maximum Operating Schedule:				
		hours/day		days/week
		weeks/year	8,760	hours/year
6. Operating Capacity/Schedule Comment (limit to 200 characters): **Maximum heat input at ISO conditions and natural gas firing (LHV); maximum for oil firing is 1,811 MMBtu/hr (ISO-LHV) and 180 MW; Higher power modes – gas is 1,680 MMBtu/hr and 182 MW. The maximum heat input for the HRSG duct burners is 550 MMBtu/hr.**				

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

See Attachment PMR8-EU1-D for operational requirements.
See PSD Report for permitting requirements.

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

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram? **See PSD Report**	2. Emission Point Type Code: **1**

3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point):

Exhausts through the HRSG stack during combined cycle operation and through the bypass stack during simple cycle operation.

4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:

5. Discharge Type Code: **V**	6. Stack Height: **HRSG-120 / Bypass-80** feet	7. Exit Diameter: **HRSG-19 / Bypass-22** feet
8. Exit Temperature: **202 / 1,116** °F	9. Actual Volumetric Flow Rate: **1,004,150 / 2,389,462** acfm	10. Water Vapor: **8.4** %

11. Maximum Dry Standard Flow Rate: **800,000** dscfm	12. Nonstack Emission Point Height: feet

13. Emission Point UTM Coordinates:

Zone: **17** East (km): **543.1** North (km): **2992.9**

14. Emission Point Comment (limit to 200 characters):

Stack parameters for ISO operating condition firing natural gas above; for oil 295 / 1,098°F and 1,193,859 / 2,735,300 ACFM; HPM 205 / 1,130°F and 1,014,759 / 2,426,858 (combined cycle / simple cycle).

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

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Distillate (No. 2) Fuel Oil**		
2. Source Classification Code (SCC): **20100101**	3. SCC Units: **1,000 gallons used**	
4. Maximum Hourly Rate: **14**	5. Maximum Annual Rate: **7,000**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.05**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **130**
10. Segment Comment (limit to 200 characters): **Million Btu per SCC Unit = 129.9 (rounded to 130). Based on 7.1 lb/gal; LHV of 18,300 Btu/lb, ISO conditions, 500 hrs/yr operation.**		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Natural Gas**		
2. Source Classification Code (SCC): **20100201**	3. SCC Units: **Million Cubic Feet**	
4. Maximum Hourly Rate: **1.68**	5. Maximum Annual Rate: **14,754**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **950**
10. Segment Comment (limit to 200 characters): **Based on 950 Btu/cf (LHV); ISO conditions and 8,760 hrs/yr operation.**		

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM			EL
SO_2			EL
NO_x	025, 028	065	EL
CO			EL
VOC			EL
PM_{10}			EL

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units -
Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **37.8** lb/hour **63.4** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing, all loads. TPY see PSD Report, Section 2, Table 2-5; ISO conditions.**	

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **37.8 lb/hr**	4. Equivalent Allowable Emissions: **37.8** b/hour **63.4** tons/year
5. Method of Compliance (limit to 60 characters): **Annual stack test; EPA Methods 5 or 17; if > 400 hours**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Allowable emissions during oil firing - all loads; 500 hrs/yr. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units -
Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **37.8** lb/hour **63.4** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing, all loads. TPY see PSD Report, Section 2.0, Table 2-5; ISO conditions.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **17.2 lb/hr**	4. Equivalent Allowable Emissions: **17.2** lb/hour **63.4** tons/year
5. Method of Compliance (limit to 60 characters): **VE Test < 10% opacity**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Allowable emissions during gas firing - all loads; 8,760 hrs/yr. See PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **SO_2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **103.1** lb/hour **70.0** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Emission Factor: 2 grain S per 100 CF gas; 0.05% S oil; lb/hr based on oil firing at 100% load and 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 1 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.05% Sulfur Oil**	4. Equivalent Allowable Emissions: **103.1** lb/hour **70.0** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel Sampling**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil firing max @ 35°F; 100% load; TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **SO_2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **103.1** lb/hour **70.0** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Emission Factor: 2 grain S per 100 CF gas; 0.05% S oil; lb/hr based on oil firing at 100% load and 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions **2** of **3**

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **See Comment**	4. Equivalent Allowable Emissions: **13.3** lb/hour **70.0** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel Sampling**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Requested allowable emissions and units: Pipeline Natural Gas. natural gas firing CT with duct firing, 1 gram/100 cf - 35°F, 100% load; TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **SO_2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **103.1** lb/hour **70.0** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Emission Factor: 2 grain S per 100 CF gas; 0.05% S oil; lb/hr based on oil firing at 100% load and 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **See Comment**	4. Equivalent Allowable Emissions: **10.6** lb/hour **70** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel Sampling**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Requested allowable emissions and units: Pipeline Natural Gas. HPM firing, 1 gram/100 cf - 35°F, 100% load; 60 hrs/yr. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **SC-333.8 / CC-95.4** lb/hour **169.4** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 1 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **SC - 42 ppmvd, CC - 12 ppmvd**	4. Equivalent Allowable Emissions: **333.8 / 95.4** lb/hour **169.4** tons/year
5. Method of Compliance (limit to 60 characters): **CEM - 24-Hour Block Average**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Requested Allowable Emissions is at 15% O_2-100% load. Oil firing; max @ 35°F; 100% load; TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **SC-333.8 / CC-95.4** lb/hour **169.4** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **SC - 9 ppmvd, CC - 2.5 ppmvd**	4. Equivalent Allowable Emissions: **61.3 / 24.2** lb/hour **169.4** tons/year
5. Method of Compliance (limit to 60 characters): **CEM - 24-Hour Block Average**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Requested Allowable Emissions and Units is at 15% O_2-100% load. Gas firing; 35°F; 100% load; TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **SC-333.8 / CC-95.4** lb/hour **169.4** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **15 ppmvd**	4. Equivalent Allowable Emissions: **105.1** lb/hour **169.4** tons/year
5. Method of Compliance (limit to 60 characters): **CEM - 24-Hour Block Average**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Requested Allowable Emissions and Units is at 15% O_2-100% load. HPM firing; 35°F; 100% load; TPY @ 59°F, 60 hrs/yr. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **89.0** lb/hour **205.4** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. TPY see PSD Report Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 1 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **20 ppmvd - Baseload**	4. Equivalent Allowable Emissions: **68.1** lb/hour **205.4** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 10; high load**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil firing; max @ 35°F; 100% load; TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **89.0** lb/hour **205.4** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **9 ppmvd**	4. Equivalent Allowable Emissions: **28.6** lb/hour **205.4** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 10; high and low load**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Gas firing; 35°F; 100% load; TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **89.0** lb/hour **205.4** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. Tons/yr see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **15 ppmvd**	4. Equivalent Allowable Emissions: **89.0** lb/hour **205.4** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 10; high load**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **HPM and duct firing; 80°F; 100% load; TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **11.69** lb/hour **27.6** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A. VOC emissions exclusive of background VOC concentrations.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions **1** of **3**

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **3.5 ppmvw**	4. Equivalent Allowable Emissions: **6.0** lb/hour **27.6** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 25A; high and low load**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil firing; max @ 35°F; 100% load; TPY see PSD Report, Section 2.0, Table 2.5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **11.69** lb/hour **27.6** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **6.2 ppmvd, includes CT and duct burner**	4. Equivalent Allowable Emissions: **11.69** lb/hour **27.6** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 25A; high and low load**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Additional requested allowable emissions and units: Gas firing; 35°F; 100% load; TPY see PSD Report, Section 2.0, Table 2.5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **11.69** lb/hour **27.6** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **1.5 ppmvw**	4. Equivalent Allowable Emissions: **2.8** lb/hour **27.6** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 25A; high and low load**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Additional requested allowable emissions and units: HPM firing; 35°F; 100% load; TPY see PSD Report, Section 2.0, Table 2.5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM_{10}**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **37.8** lb/hour **63.4** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 59°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **37.8 lb/hr**	4. Equivalent Allowable Emissions: **37.8** lb/hour **63.4** tons/year
5. Method of Compliance (limit to 60 characters): **Annual stack test; EPA Method 5 or 17 if >400 hours**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Allowable emissions during oil firing - all loads; 500 hrs/yr. See PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM_{10}**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **37.8** lb/hour **63.4** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing, all loads. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **17.2 lb/hr**	4. Equivalent Allowable Emissions: **17.2** lb/hour **63.4** tons/year
5. Method of Compliance (limit to 60 characters): **VE Test < 10% opacity**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Gas firing; all loads; 8,760 hrs/yr. See PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

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

Visible Emissions Limitation: Visible Emissions Limitation 1 of 2

1. Visible Emissions Subtype: **VE20**	2. Basis for Allowable Opacity: [X] Rule [ ] Other

3. Requested Allowable Opacity:
Normal Conditions: **10** % Exceptional Conditions: %
Maximum Period of Excess Opacity Allowed: min/hour

4. Method of Compliance:
Annual VE Test EPA Method 9

5. Visible Emissions Comment (limit to 200 characters):

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

Continuous Monitoring System: Continuous Monitor 1 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **NO_x**

3. CMS Requirement: [X] Rule [ ] Other

4. Monitor Information: **Not yet determined**
Manufacturer:
Model Number: Serial Number:

5. Installation Date:	6. Performance Specification Test Date:

7. Continuous Monitor Comment (limit to 200 characters):

NO_x CEM proposed to meet requirements of 40 CFR Part 75 have been installed for this unit. Information previously submitted to DEP.

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

Visible Emissions Limitation: Visible Emissions Limitation 2 of 2

1. Visible Emissions Subtype: **VE99**	2. Basis for Allowable Opacity: [ ] Rule [X] Other
3. Requested Allowable Opacity: Normal Conditions: % Exceptional Conditions: **100** % Maximum Period of Excess Opacity Allowed: **6** min/hour	
4. Method of Compliance: **None**	
5. Visible Emissions Comment (limit to 200 characters): **DEP Rule 62-201.700(1), Allowed for 2 hours (120 minutes) per 24 hours for start up, shutdown and malfunction.**	

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

Continuous Monitoring System: Continuous Monitor 2 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **NO_x**
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: **Not yet determined** Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): **Parameter Code: WTF. Required by 40 CFR Part 60; subpart GG; 60.334.**	

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

Supplemental Requirements

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

Additional Supplemental Requirements for Title V Air Operation Permit Applications

11. Alternative Methods of Operation [ ] Attached, Document ID:________ [ ] Not Applicable
12. Alternative Modes of Operation (Emissions Trading) [ ] Attached, Document ID:________ [ ] Not Applicable
13. Identification of Additional Applicable Requirements [ ] Attached, Document ID:________ [ ] Not Applicable
14. Compliance Assurance Monitoring Plan [ ] Attached, Document ID:________ [ ] Not Applicable
15. Acid Rain Part Application (Hard-copy Required) [ ] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a)) Attached, Document ID:________ [ ] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) Attached, Document ID:________ [ ] New Unit Exemption (Form No. 62-210.900(1)(a)2.) Attached, Document ID:________ [ ] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) Attached, Document ID:________ [ ] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) Attached, Document ID:________ [ ] Phase NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) Attached, Document ID:________ [ ] Not Applicable

III. EMISSIONS UNIT INFORMATION

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

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

Emissions Unit Description and Status

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

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

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

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

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

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

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

3. Description of Emissions Unit Addressed in This Section (limit to 60 characters):

Natural Gas Heaters

4. Emissions Unit Identification Number: [ ] No ID
ID: [X] ID Unknown

5. Emissions Unit Status Code:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
C		**49**	[ ]

9. Emissions Unit Comment: (Limit to 500 Characters)

This emission unit is Natural Gas Heaters for the GE Frame 7FA combustion turbines operating in simple cycle mode (see PSD Report).

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method): **Dry Low NO_X combustion - Natural gas firing**	
2. Control Device or Method Code(s): **25**	

Emissions Unit Details

1. Package Unit: Manufacturer: **Gas Tech or Equivalent**	Model Number:	
2. Generator Nameplate Rating:	MW	
3. Incinerator Information: Dwell Temperature: Dwell Time: Incinerator Afterburner Temperature:		 °F seconds °F

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

Emissions Unit Operating Capacity and Schedule

1.	Maximum Heat Input Rate:		23.71	mmBtu/hr
2.	Maximum Incineration Rate:	lb/hr		tons/day
3.	Maximum Process or Throughput Rate:			
4.	Maximum Production Rate:			
5.	Requested Maximum Operating Schedule:			
		hours/day		days/week
		weeks/year	3,390	hours/year
6.	Operating Capacity/Schedule Comment (limit to 200 characters):			
	Maximum heat input per unit when natural gas firing (HHV).			

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

See PSD Report for permitting requirements	

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

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram? **See PSD Report**	2. Emission Point Type Code: **1**

3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point):

Exhausts through a single stack.

4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:

5. Discharge Type Code: **V**	6. Stack Height: **30** feet	7. Exit Diameter: **1** foot
8. Exit Temperature: **700** °F	9. Actual Volumetric Flow Rate: **11,736** acfm	10. Water Vapor: %

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

13. Emission Point UTM Coordinates:

Zone: **17** East (km): **543.1** North (km): **2992.9**

14. Emission Point Comment (limit to 200 characters):

Each Heater will have one stack.

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

Segment Description and Rate: Segment 1 of 1

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Natural Gas < 100 MMBtu/hr**		
2. Source Classification Code (SCC): **10100602**	3. SCC Units: **Million Cubic Feet**	
4. Maximum Hourly Rate: **0.023**	5. Maximum Annual Rate: **311.9**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.05**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **1020**
10. Segment Comment (limit to 200 characters): **Maximum hourly based on 1020 Btu/cf (HHV) for each heater; maximum annual based on 3,390 hrs/yr operation for 4 heaters.**		

Segment Description and Rate: Segment _____ of _____

1. Segment Description (Process/Fuel Type) (limit to 500 characters):		
2. Source Classification Code (SCC):	3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment (limit to 200 characters):		

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
NO_X	026		EL
CO			EL

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **NO_X**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **2.36** lb/hour **16** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GasTech, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on one heater. TPY based on 3,390 hrs/yr for 4 heaters.**	

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.1 lb/MMBtu**	4. Equivalent Allowable Emissions: **2.36** b/hour **16** tons/year
5. Method of Compliance (limit to 60 characters):	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **See PSD Report, Section 2.0.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **1.79** lb/hour **12** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GasTech, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on one heater. TPY based on 3,390 and 4 heaters.**	

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.075 lb/MMBtu**	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **See PSD Report, Section 2.0.**	

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

Visible Emissions Limitation: Visible Emissions Limitation 1 of 2

1. Visible Emissions Subtype: **VE20**	2. Basis for Allowable Opacity: [ ] Rule [X] Other
3. Requested Allowable Opacity: Normal Conditions: **10** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **Annual VE Test EPA Method 9**	
5. Visible Emissions Comment (limit to 200 characters): **Maximum for gas firing. Rule 62-296.320 allows 20% opacity**	

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

Continuous Monitoring System: Continuous Monitor ______ of______

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	[ ] Rule [ ] Other
4. Monitor Information: Manufacturer: Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters):	

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

Visible Emissions Limitation: Visible Emissions Limitation 2 of 2

1. Visible Emissions Subtype: **VE99**	2. Basis for Allowable Opacity: [X] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: % Exceptional Conditions: **100** % Maximum Period of Excess Opacity Allowed: **6** min/hour	
4. Method of Compliance: **None**	
5. Visible Emissions Comment (limit to 200 characters): **DEP Rule 62-201.700(1), Allowed for 2 hours (120 minutes) per 24 hours for start up, shutdown and malfunction.**	

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

Continuous Monitoring System: Continuous Monitor ______ of ______

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters):	

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

Supplemental Requirements

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

Additional Supplemental Requirements for Title V Air Operation Permit Applications

11. Alternative Methods of Operation [ ] Attached, Document ID:________ [ ] Not Applicable
12. Alternative Modes of Operation (Emissions Trading) [ ] Attached, Document ID:________ [ ] Not Applicable
13. Identification of Additional Applicable Requirements [ ] Attached, Document ID:________ [ ] Not Applicable
14. Compliance Assurance Monitoring Plan [ ] Attached, Document ID:________ [ ] Not Applicable
15. Acid Rain Part Application (Hard-copy Required) [ ] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a)) Attached, Document ID:________ [ ] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) Attached, Document ID:________ [ ] New Unit Exemption (Form No. 62-210.900(1)(a)2.) Attached, Document ID:________ [ ] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) Attached, Document ID:________ [ ] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) Attached, Document ID:________ [ ] Phase NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) Attached, Document ID:________ [ ] Not Applicable

III. EMISSIONS UNIT INFORMATION

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

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

Emissions Unit Description and Status

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

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

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

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

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

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

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

3. Description of Emissions Unit Addressed in This Section (limit to 60 characters):

Cooling Tower

4. Emissions Unit Identification Number: [ ] No ID
ID: [X] ID Unknown

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

9. Emissions Unit Comment: (Limit to 500 Characters)

This emission unit is a 18 cell mechanical draft cooling tower (see PSD Report).

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method): **Drift Eliminators**	
2. Control Device or Method Code(s):	

Emissions Unit Details

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

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

Emissions Unit Operating Capacity and Schedule

1. Maximum Heat Input Rate:				mmBtu/hr
2. Maximum Incineration Rate:		lb/hr		tons/day
3. Maximum Process or Throughput Rate:				
4. Maximum Production Rate:				
5. Requested Maximum Operating Schedule:				
	24	hours/day	7	days/week
	52	weeks/year	8,760	hours/year
6. Operating Capacity/Schedule Comment (limit to 200 characters):				

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

See PSD Report for permitting requirements	

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

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram? **See PSD Report**	2. Emission Point Type Code: **1**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point): **Exhausts through 18 stacks.**	
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:	

5. Discharge Type Code: **V**	6. Stack Height: **45** feet	7. Exit Diameter: **38** foot
8. Exit Temperature: **90** °F	9. Actual Volumetric Flow Rate: **1,386,055** acfm	10. Water Vapor: %

11. Maximum Dry Standard Flow Rate: dscfm	12. Nonstack Emission Point Height: feet
13. Emission Point UTM Coordinates: Zone: **17** East (km): **543.1** North (km): **2992.9**	
14. Emission Point Comment (limit to 200 characters): **Volume is per cell.**	

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

Segment Description and Rate: Segment 1 of 1

1. Segment Description (Process/Fuel Type) (limit to 500 characters):		
2. Source Classification Code (SCC):	3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment (limit to 200 characters):		

Segment Description and Rate: Segment ____ of ____

1. Segment Description (Process/Fuel Type) (limit to 500 characters):		
2. Source Classification Code (SCC):	3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment (limit to 200 characters):		

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM_{10}			EL
PM			EL

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: PM_{10}	2. Total Percent Efficiency of Control:
3. Potential Emissions: 4.65 lb/hour 20.4 tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: FPL, 2001; Golder, 2002	7. Emissions Method Code: 2
8. Calculation of Emissions (limit to 600 characters): See PSD Report, Section 2.0; and Appendix A.	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 4.65 lb/hour	4. Equivalent Allowable Emissions: 4.65 b/hour 20.4 tons/year
5. Method of Compliance (limit to 60 characters):	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **15.51** lb/hour **67.9** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **FPL, 2001; Golder, 2002**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **15.51** lb/hr	4. Equivalent Allowable Emissions: **15.51** lb/hour **67.9** tons/year
5. Method of Compliance (limit to 60 characters):	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

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

Supplemental Requirements

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

Additional Supplemental Requirements for Title V Air Operation Permit Applications

11. Alternative Methods of Operation [ ] Attached, Document ID:________ [ ] Not Applicable
12. Alternative Modes of Operation (Emissions Trading) [ ] Attached, Document ID:________ [ ] Not Applicable
13. Identification of Additional Applicable Requirements [ ] Attached, Document ID:________ [ ] Not Applicable
14. Compliance Assurance Monitoring Plan [ ] Attached, Document ID:________ [ ] Not Applicable
15. Acid Rain Part Application (Hard-copy Required) [ ] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a)) Attached, Document ID:________ [ ] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) Attached, Document ID:________ [ ] New Unit Exemption (Form No. 62-210.900(1)(a)2.) Attached, Document ID:________ [ ] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) Attached, Document ID:________ [ ] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) Attached, Document ID:________ [ ] Phase NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) Attached, Document ID:________ [ ] Not Applicable

PSD REPORT

1.0 INTRODUCTION

Florida Power & Light Company (FPL), proposes to license, construct, and operate a nominal 1,150-megawatt (MW) combined cycle unit, at the existing Martin Power Plant located in unincorporated Martin County, Florida (Figure 1-1). Martin Unit 8 will be located south of the existing Units 3 and 4 on approximately 44-acres of the 11,300–acre Martin Plant site. The combined cycle unit will consist of four General Electric (GE) 7FA combustion turbines (CTs) and associated electric generators, four heat recovery steam generators (HRSGs) and single steam turbine with associated electric generator. This is referred to as a "4 on 1" combined cycle unit. The two existing simple cycle CTs, referred to as Units 8A and 8B, will be equipped with HRSGs to produce steam. The two new CTs with associated HRSGs, to be referred to as Units 8C and 8D, will be added along with the steam turbine/electric generator. A mechanical draft cooling tower may be installed and is an option for the Project. Together these facilities are referred to as the "Project".

Martin Units 8A and 8B are currently authorized to operate up to a heat input equivalent of 3,390 hours per year in simple cycle mode that includes a heat input equivalent of 500 hours of year operation using light distillate oil [Florida Department of Environmental Protection (FDEP) Permit No. 0850001-008-AC; PSD-FL-286]. As part of the Martin Unit 8 Project, these units will be converted to combined cycle with substantial emission reductions for NO_x. Simple cycle operation for these units will continue until they can be integrated into combined cycle configuration. The new CTs (i.e., Unit 8C and 8D) will be identical to the existing CTs and are proposed to operate in simple cycle mode during the first year of operation. When combined cycle is complete, the option for limited simple cycle operation is being proposed.

The CTs will use dry low-nitrogen oxide (DLN) combustion technology when operating on natural gas and water injection for nitrogen oxide (NO_x) control when operating on light distillate fuel oil and power augmentation. Each CT/HRSG will be installed with selective catalytic reduction (SCR) to further reduce emissions of NO_x. Each CT/HRSG will also have the capability of operating in simple cycle mode. Each HRSG will be equipped with duct burners that will fire only natural gas with a maximum heat input of 550 million British thermal units per hour (MMBtu/hr). The primary fuel for the CTs will be natural gas with distillate fuel oil used as backup fuel. Fuel oil will contain a maximum sulfur content of 0.05 percent.

The permitting of the Project requires an Air Construction Permit and PSD review. PSD review requires air quality assessments for determining the facility's compliance with state and federal new source review (NSR) regulations, including addressing applicable PSD and nonattainment review requirements. The critical aspects of these assessments include the air quality impact analyses performed using appropriate air dispersion models and the Best Available Control Technology (BACT) analyses performed to evaluate the selected emission control technology.

The proposed Project will be a modification to an existing major air pollution source that will result in net increases in air emissions. The U.S. Environmental Protection Agency (EPA) has implemented regulations requiring a PSD review for new or modified sources that increase air emissions above certain threshold amounts. Because the threshold amounts for a modification will be exceeded by the Project, the Project is subject to PSD review. PSD regulations are promulgated under 40 Code of Federal Regulations (CFR) Part 52.21 and implemented by the FDEP. Florida's PSD regulations are codified in Rules 62-212.400, Florida Administrative Code (F.A.C.) and have been delegated by EPA to FDEP. These Florida PSD regulations incorporate the requirements of EPA's PSD regulations.

Based on the emissions from the proposed facility, PSD review is required for each of the following regulated pollutants:

- Particulate matter (PM) as total suspended particulate matter (TSP),
- Particulate matter with aerodynamic diameter of 10 microns or less (PM_{10}),
- Nitrogen dioxide (NO_2),
- Sulfur dioxide (SO_2),
- Carbon monoxide (CO),
- Volatile organic compounds (VOCs), and
- Sulfuric acid mist.

Martin County has been designated as an attainment area for all criteria pollutants [i.e., attainment: (O_3), PM_{10}, SO_2, CO, and NO_2; unclassifiable: lead] and is a PSD Class II area for PM_{10}, SO_2, and NO_2; therefore, the PSD review will follow regulations pertaining to such designations.

The air permit application is divided into seven major sections:

- Section 2.0 presents a description of the Project, including air emissions and stack parameters.
- Section 3.0 provides a review of the PSD and nonattainment requirements applicable to the Project.
- Section 4.0 includes the control technology review with discussions on BACT.
- Section 5.0 discusses the ambient air monitoring analysis (pre-construction monitoring) required by PSD regulations.
- Section 6.0 presents a summary of the air modeling approach and results used in assessing compliance of the proposed facility with ambient air quality standards (AAQS), and PSD increments.
- Section 7.0 provides the additional impact analyses for soils, vegetation, and visibility.

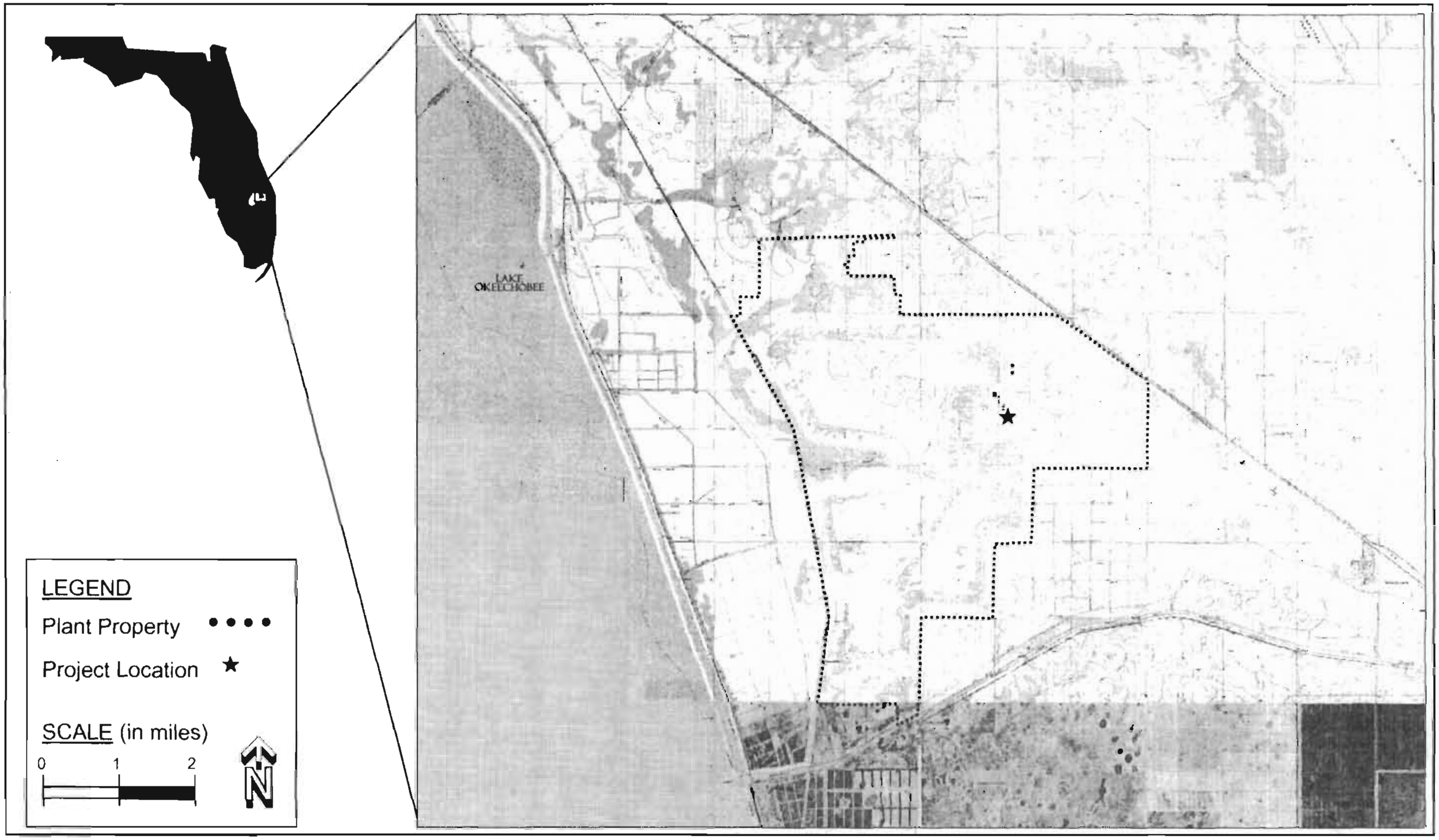

Figure 1-1. FPL Martin Plant Site Location

Source: Bechtel Power Corporation, 1989; Golder, 2002.

FPL

Martin Unit 8

2.0 PROJECT DESCRIPTION

2.1 SITE DESCRIPTION

The Martin Plant site (shown in Figure 1-1) consists of 11,300 acres that is wholly owned by FPL. The site is comprised of a 6,800-acre cooling pond and approximately 400 acres for the existing power facilities. The remaining area consists of undeveloped or agricultural land. There is minimal industrial, commercial, and residential development within a 5-kilometer (km) radius of the site. The plant elevation will be approximately 32 feet above sea level. The terrain surrounding the site is flat.

Natural gas is supplied to the Martin Plant by two lateral pipelines connected to the Florida Gas Transmission (FGT) natural gas pipeline located to the east of the site. A segment of the new pipeline will be located north and east of the Martin Plant, which may eventually provide gas to the site.

2.2 POWER PLANT

The proposed facility will be configured as a 4 on 1 combined unit for base load service. The combined cycle unit will consist of four GE Frame 7FA CTs with an associated HRSGs and a steam turbine-generator. The CTs will use DLN combustion technology (when firing natural gas) and water injection (when firing distillate oil) to minimize NO_x formation. SCR will be installed in each HRSG to further reduce emissions of NO_x. Natural gas will be used as the primary fuel, and light distillate fuel oil will be used as an alternate fuel. Fuel oil usage will be limited to the equivalent of 500 hours per year (hr/yr) at full load. Each HRSG will be equipped with duct burners with a maximum heat input of 550 MMBtu/hr. Duct firing will be limited to an equivalent heat input of 550 MMBtu/hr for 2,880 hours or 1,584,000 million Btu/year per CT/HRSG.

Plant performance for the GE 7FA CTs was developed for natural gas and oil at 50-, 75-, and 100-percent load and 35 degrees Fahrenheit (°F), 59°F, 75°F, and 95°F ambient dry bulb temperatures. Nominal part load percentages herein are relative to 100-percent load without evaporative cooling. Data were also developed for higher power modes (HPM) that include peak operation and power augmentation for the range of operating loads and temperatures. In addition, the CTs can operate with power augmentation (data are provided for ambient temperature of 80°F). More detailed discussions on these operations are presented in Section 2.3.

The CTs will be capable of operating from 50- to 100-percent base load. The efficiency of the CTs decreases at part load. As a result, the economic incentive is to dispatch the plant to keep the units operating as near to base load as possible.

Natural gas will be transported to the site via pipeline, and fuel oil will be trucked to the site. The distillate fuel oil, which will have a maximum sulfur content of 0.05 percent, will be stored onsite in two aboveground storage tanks, sized to hold approximately 50,000 barrels (2 million gallons). One of these tanks is existing, while an additional aboveground storage tank will be installed. The second tank was previously approved during the permitting of Units 3 and 4 and Units 8A and 8B.

Air emissions control will consist of using state-of-the-art DLN burners in the CTs when firing natural gas. Each GE Frame 7FA will be equipped with the GE DLN-2.6 combustion system that regulates the distribution of fuel delivery to a multi-nozzle, total premix combustor arrangement. The fuel flow distribution to each combustion system fuel nozzle is regulated to maintain unit load and minimize turbine emissions. The DLN-2.6 combustion system consists of six fuel nozzles per combustion can, with each operating as a fully premixed combustor. Of the six nozzles, five are located radially and one is in the center. The fuel system is fully automated and sequences the DLN-2.6 combustion system through a number of staging modes prior to reaching full load. The GE Frame 7FA has 14 combustors per turbine. Water injection will be used for NO_x control when firing distillate fuel oil. The SO_2 emissions will be controlled by the use of low-sulfur fuels. Good combustion practices and clean fuels will also minimize potential emissions of PM, CO, VOC, and other pollutants (e.g., trace metals). These engineering and environmental designs maximize control of air emissions while minimizing economic, environmental, and energy impacts (see Section 4.0 for the BACT evaluation).

SCR reactors for Unit 8 will be located in the HRSG to provide the proper operating temperature range for the required reaction between ammonia and NO_x to achieve the proposed BACT emission rate and to assure the economical operation of the system. The NO_x is reduced by a chemical reaction with the ammonia in the presence of the catalyst. The catalyst will be provided in modules, which will be installed into a structural steel reactor housing that is incorporated into the HRSG. Ammonia is carried by a diluent and injected into the exhaust gas upstream of the catalyst modules. The reactor housing will include an internal support structure for the catalyst modules, man-access and catalyst loading openings and instrument connections for monitoring catalyst performance. The ammonia handling system will include primary and standby diluent air blowers (each sized for 100-percent capacity), ammonia flow control and measurement devices, an ammonia/air mixing chamber, distribution header(s), and an ammonia injection grid (AIG). Overall control of the system will be by the distributed control system (DCS).

Each CT will have an evaporative cooling (fogger) at the turbine air inlet that reduces the inlet air temperature and increases both the efficiency and power output at elevated ambient temperatures. This cooling system will only operate when the ambient temperature is 60°F or greater and the CTs are operating. This cooling system adds water vapor to the compressor inlet of the CTs, which increases the mass flow of air by evaporative cooling, but does not affect emissions of regulated pollutants. The CTs can operate without the evaporative coolers in service.

The first year of operation will consist of simple cycle only, including fuel heating up to 3,390 hours per year per CT. The CTs in simple cycle mode will require fuel heating for the DLN system when firing natural gas. Two of these units are existing (8A and 8B) and two more (8C and 8D) will be added. Beyond the first year of operation, fuel heating will include 1,000 hours per year per CT.

2.3 PROPOSED SOURCE EMISSIONS AND STACK PARAMETERS

The estimated maximum hourly emissions and exhaust information representative of each CT/HRSG operating at base-load conditions (100-percent load), 75-percent load and 50-percent load conditions in combined cycle mode are presented in Tables 2-1 and 2-2 for natural gas and distillate oil firing, respectively. Table 2-1 also includes emissions and exhaust information for duct firing. The estimated maximum hourly emissions and exhaust information representative of the simple cycle operation at base-load conditions (100-percent load), 75-percent load, and 50-percent load conditions are presented in Tables 2-3 and 2-4 for natural gas and distillate oil firing, respectively. The data are presented for ambient temperatures of 35°F, 59°F, 75°F, and 95°F. These temperatures represent the range of ambient temperatures that the CTs are most likely to experience. The performance data for the operating conditions are given in Appendix A.

The proposed pollutant gaseous emission concentrations and PM_{10} emission rates assumed for the Project are:

Pollutant	Natural Gas	Distillate Oil
NO_x (ppmvd @ 15-percent O_2)	2.5 (CC)[a] and 9/15 (SC/SC-HPM)[a]	12 (CC)[a] and 42 (SC)[a]
CO (ppmvd)	9/15(HPM)/29.5(CC/DF)	20
VOC as CH_4 (ppmvw)	1.5	3.5
SO_x as SO_2	Calculated Based on Fuel (2.0 grains S/100 SCF)	Calculated Based on Fuel (0.05-percent sulfur)
PM_{10} (lb/hr) (dry filterable)	17.2 (CC) and 9 (SC) 11.1 (HPM)	37.8 (CC) and 17 (SC)
Note: CC = combined cycle; DF = Duct firing; SC = simple cycle; ppmvd = Parts per million volume, dry; lb/hr = pounds per hour; ppmvw = Parts per million, volume, wet; HPM = higher power mode (peak and power augmentation); Values for ISO conditions at base load; [a] three-hour average		

The maximum short-term emission rates (lb/hr) generally occur at base load, 35°F operation, where the CT has the greatest output and greatest fuel consumption. The HPM reflects either operating with power augmentation or operating in peak mode. Power augmentation is the use of steam when firing natural gas at loads above 95 percent to increase power output. About 1.5 lb steam per lb of fuel is used in this mode of operation. The existing CTs (Unit 8A and 8B) are authorized to operate in power augmentation mode for 400 hours per year. Peak mode is achieved by slightly increasing the exhaust temperature through the automated control system by adjusting the fuel distribution between the fuel nozzles while in pre-mix mode. The existing CTs are authorized to operate 60 hours in peak mode. Both power augmentation and peak modes of operation is possible while the turbine is in combined and simple cycle mode.

Based on an ambient temperature of 59°F, the emission rates used to calculate maximum potential annual emissions for the CTs/HRSGs for regulated air pollutants are presented in Table 2-5 for the facility. To produce the maximum annual emissions, it is assumed that each CT/HRSG would operate for 7,760 hours in combined cycle mode and 1,000 hours in simple cycle mode. Of the 7,760 combined cycle hours, 3,980 hours will be firing natural gas; 2,880 hours at 100-percent load with duct firing (550 MMBtu/hr); 400 hours at 100-percent load with duct firing and steam power augmentation, or peak operations. Simple cycle operation will consist of 500 hours at 100-percent load, natural gas; and 500 hours firing distillate oil at 100-percent load. For the two new CTs, simple cycle operation was assumed for the first year of operation to be at base load with 2,890 hours firing natural gas and 500 hours firing distillate oil. After the first year, simple cycle operation for the four CTs would not exceed an aggregate equivalent of 4,000 hours per year with a maximum of 2,000 hours per year of operation on distillate oil. The proposed limit on fuel oil is 3,838,000 MMBtu per year (1,919 MMBtu/hr x 4 CTs x 500 hours.) The potential emissions are based on the 59°F ambient air condition since it represents a conservative average when the annual average temperatures are slightly higher than 70°F.

Process flow diagrams of a CT/HRSG, operating at base load conditions with a compressor inlet temperature of 59°F, are presented in Figure 2-1.

The emissions information for the two new fuel heaters are presented in Table 2-6. The emissions for the optional cooling tower is presented in Table 2-7. A summary of the maximum total potential annual emissions estimated for the Project is given in Table 2-8.

Emission factors for hazardous air pollutants (HAPs) were evaluated based on the revised AP-42 emission factors and the EPA Combustion Turbine Emissions Database. The HAP emissions are based on emission factors from the April 2000 revision of EPA's AP-42 emission factors for large stationary combustion turbines. Summaries of the emission factors and emissions for fuel oil firing and gas firing are presented in Tables A-15 through A-16.

Except for formaldehyde and toluene, the emission factors are those presented in Tables 3.1-4 and 3.1-5 of the revised AP-42 section for combustion turbines. For formaldehyde, a review of EPA's database was conducted and an emission factor was estimated based on comparisons of the turbines and emission characteristics from EPA's database to those proposed for this project. A discussion regarding this review and estimation of the formaldehyde emission factor is presented in the following section.

The recent EPA emission factor suggests formaldehyde emissions from gas turbines of 710 lb/10^{12} Btu when firing natural gas at loads greater than 80 percent and 280 lb/10^{12} Btu when firing distillate oil. The EPA suggested emission factor for all loads is 3,100 lb/10^{12} Btu. Since the proposed CTs will fire primarily natural gas, with limited oil firing, the worst-case annual emissions would be from natural gas firing.

The emission factors are not appropriate for the proposed CTs based on several factors. First, and most importantly, the data used to develop the AP-42 emission factors are not representative of the GE Frame 7FA combustion turbine. Second, a review of the data of the pertinent information in the EPA database that relates to the characteristics clearly suggests a much lower emission factor for formaldehyde. Some of the important aspects of the EPA Gas Turbine Database related to formaldehyde emissions are as follows.

- The formaldehyde emissions are from small (< 30 MW) gas turbines. The available data are from an average capacity of about 28 MW. More importantly, the median capacity, or the turbine size where an equal number of turbines are above and below that size, is about 15 MW. Data from only 8 large turbines (>30 MW) are included in the EPA database, with a maximum size of 88 MW.
- In contrast to the AP-42 emission factors for formaldehyde, which are based on an average value, the median value is substantially lower. For all loads, the median formaldehyde emission factor is about 320 lb/10^{12} Btu; for turbine loads greater than 50 percent, the median emission factor is about 110 lb/10^{12} Btu. Since the median emission factor is about 8 to ten times lower than the average factor, this clearly points to the large range in formaldehyde emissions and how the individual turbine combustion characteristics can influence the results. The median is a measure of the middle of the distribution and in distributions where there is symmetry about the mean, and where the mean and median coincide. However, in highly skewed distributions, as that observed for formaldehyde emissions, the median is more representative of a "truer average" since the median is not influenced by extreme values.
- There is a strong relationship between formaldehyde and CO emissions, as noted by EPA in the support document and, and as observed in the data. Gas turbines with higher CO emissions had higher observed formaldehyde emissions. An evaluation of the coincident CO and formaldehyde data indicates that formaldehyde emissions were 150 lb/10^{12} Btu when the CO emissions are less than 0.1 lb/MMBtu. The CO emission guarantees for the GE Frame 7FA is about 0.016 lb/MMBtu.

At present, there are no confirmed test data of formaldehyde emissions from similar GE Frame 7FA combustion turbines.

Based on the available data, formaldehyde emissions would be within the range of 100 to 150 $lb/10^{12}$ Btu. An emission factor of 150 $lb/10^{12}$ Btu for formaldehyde has been used in this application.

An emission factor for toluene of 33 $lb/10^{12}$ Btu for natural gas firing was developed from the data in the EPA Combustion Turbine Emissions Database. This factor is based on the median value for loads greater than 80 percent. Similar to formaldehyde emission factors, there are no confirmed test data of toluene emissions from a GE Frame 7FA. The recent EPA emission factor, which is based on much smaller turbines than those proposed for this project, suggests toluene emissions from gas turbines of 130 $lb/10^{12}$ Btu when firing natural gas at loads greater than 80 percent. For all loads, the average and median EPA factors are 94 and 19 $lb/10^{12}$ Btu, respectively. Since the median emission factor is about 4 to 5 times lower than the average factor, this clearly points to the large range in toluene emissions and how the individual turbine combustion characteristics can influence the results. The emission factor of 33 $lb/10^{12}$ Btu is also about a factor of 4.5 times lower than that of formaldehyde, which is similar to the ratio of EPA's formaldehyde to toluene emission factors.

The emission factors for many of the other HAPs were developed by EPA in a manner similar to formaldehyde and toluene. For these HAPs, fewer data are available and are also considered not representative of state-of-the-art DLN combustion systems. The use of AP-42 emission factors for these HAPs are considered to provide conservative estimates of emissions.

An evaluation of the HAP emissions from the facility indicates that emissions are less than 25 TPY for all HAPs and less than 10 TPY for any single HAP. As shown in Tables A-15 and A-16, the maximum total emissions of HAPs are estimated to 16.7 TPY with maximum emissions of any single HAPs at 6.3 TPY. The requirements of 40 CFR 63.43 for a maximum achievable control technology (MACT) apply to the construction or reconstruction of a major source of HAPs. The proposed Project is not a major source of HAPS by itself and it is not a reconstruction of the existing facilities at the Martin Plant. Therefore, the requirements of 40 CFR 63.43 for a maximum achievable control technology are not applicable to the project.

2.4 SITE LAYOUT, STRUCTURES, AND STACK SAMPLING FACILITIES

A plot plan of the proposed Project is presented in Figure 2-2 and a profile is presented in Figure 2-3. The dimensions of the buildings and structures are presented in Section 6.0. Stack sampling facilities will be constructed in accordance to Rule 62-297.310(6) F.A.C.

2.5 EXCESS EMISSIONS

2.5.1 INTEGRATION TO COMBINED CYCLE

Prior to conversion from simple cycle to combined cycle, steam produced in the HRSG is used to clean the HRSG piping system and piping connecting each HRSG to the steam turbine. This will require the combustion turbine to operate at less than 50 percent load for periods exceeding the 2 hours allowed under FDEP rules for excess emission during start-up, shutdown and malfunction. This operation will result in emissions in excess of the emission limiting standards established for Units 8A and 8B and those being proposed for Units 8C and 8D for simple cycle mode. An excess emission allowance identical to that authorized for the FPL Fort Myers Repowering Project is requested for Martin Unit 8. The requested condition follows:

Section III, Specific Condition Number

The following NO_x excess emissions periods are applicable only at the end of construction and shall not exceed a total of 90 days per construction turbine:

- Emissions of NO_x from the combustion turbines CTs, in excess of the BACT limit established in Specific Condition 19, resulting from steam blow activities associated with bringing the heat recovery steam generators into operation shall be permitted provided that best operational practices are adhered to and that the Subpart GG NSPS limit of 75/110 ppmvd@15% O_2 is not exceeded. The period during which such excess emissions are authorized shall not exceed a total of 90 days per combustion turbine. The applicant shall record for each CT unit the periods of start-up for each operating mode. Excess emissions during the periods of startup shall be reported to the FDEP South District office within 30 days.

  [Applicant Request (FPL estimates that CT emissions will comply with the NSPS NO_x limit following initial compliance testing, but that low load operation necessary for steam blow activities prior to initial combined cycle operation will result in NO_x emissions above the BACT limit of 9 ppmvd@15 percent O_2. Excess emission of NO_x resulting from steam blows may occur intermittently over a period of up to 30 days per CT initially, followed by a period of up to 60 days of intermittent steams blows for the piping systems serving the six interconnected combined cycle units.)].

Section III, Specific Condition Number

Compliance with the allowable emission limiting standards shall be determined within 60 days after achieving the maximum production rate at which each unit configuration (i.e., simple cycle and combined cycle) will be operated, but no later than 180 days following initial operation of each unit configuration, and annually thereafter.

2.5.2 COLD START-UP IN COMBINED CYCLE

The start-up in combined cycle operation will require an excess emission allowance greater than two hours allowed under the FDEP rules. This occurs during cold start-up where the operating load of the CTs are limited by the amount of steam that can be accepted by the steam turbine. This will result in excess emissions. The same excess emission allowance is requested for Martin Unit 8 Project that was authorized for the FPL Fort Myers Repowering Project. Both Projects have similar steam turbines that receive steam during start-up (i.e., 400 MW). The proposed condition follows:

Excess Emissions Requirements:

- Excess emissions resulting from start-up, shutdown or malfunction of the *combustion turbines and heat recovery steam generators* 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 except during both "cold start-up" to or shutdowns from combined cycle operation. During cold start-up to combined cycle operation, up to four hours of excess emissions are allowed. During shutdowns from combined cycle operation, up to three hours of excess emissions are allowed. Cold start-up is defined as a start-up to combined cycle operation following a complete shutdown lasting at least 48 hours.
- Excess emissions from the combustion turbines resulting from start-up of the *steam turbines system* 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 12 hours per cold start-up of the steam turbine system.

[Applicant Request (FPL estimates that, on average, there will be approximately 12 start-ups to combined-cycle operation per year), G.E. Combined Cycle Start-Up Curves Data and Rules 62-210.700, 62-4.130 F.A.C.)].

Table 2-1. Stack, Operating, and Emission Data for the Combustion Turbines/HRSGs and Duct Burners for Combined Cycle Operation-
Natural Gas Combustion

		Operating and Emission Data [a] for Ambient Temperarure									
		Combustion Turbine/ HRSG					Combustion Turbine/ HRSG/ Duct Burner				
Parameter		35 °F	59 °F	75 °F	80 °F [b]	95 °F	35 °F	59 °F	75 °F	80 °F [b]	95 °F
CT/HRSG Stack Data (ft)											
Height		120	120	120	120	120	120	120	120	120	120
Diameter		19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0
100 Percent Load											
Temperature (°F)		203	202	204	204	201	189	188	189	188	190
Velocity (ft/sec)		61.6	59.0	57.3	57.9	54.5	61.0	58.4	56.7	54.1	54.3
Maximum Hourly Emissions per Unit											
SO_2	lb/hr	10.2	9.8	9.4	9.5	8.9	13.3	12.8	12.4	12.5	11.9
PM/PM_{10}	lb/hr	11.1	11.0	10.9	10.9	10.8	17.2	17.1	17.0	17.0	16.9
NO_x	lb/hr	17.0	16.3	15.6	15.9	14.7	24.2	23.6	23.1	22.1	22.3
CO	lb/hr	28.6	27.5	26.6	45.0	25.5	72.6	71.5	70.6	89.0	69.5
VOC (as methane)	lb/hr	2.9	2.7	2.6	2.6	2.5	11.7	11.5	11.4	11.4	11.3
Sulfuric Acid Mist	lb/hr	1.02	0.98	0.94	0.95	0.89	1.63	1.59	1.55	1.56	1.49
75 Percent Load											
Temperature (°F)		187	188	189	NA	190	NA	NA	NA	NA	NA
Velocity (ft/sec)		48.4	47.1	45.9	NA	44.3	NA	NA	NA	NA	NA
Maximum Hourly Emissions per Unit											
SO_2	lb/hr	8.3	7.9	7.7	NA	7.3	NA	NA	NA	NA	NA
PM/PM_{10}	lb/hr	10.7	10.6	10.5	NA	10.5	NA	NA	NA	NA	NA
NO_x	lb/hr	13.6	13.1	12.6	NA	12.0	NA	NA	NA	NA	NA
CO	lb/hr	24.4	23.5	22.7	NA	21.7	NA	NA	NA	NA	NA
VOC (as methane)	lb/hr	2.3	2.2	2.2	NA	2.1	NA	NA	NA	NA	NA
Sulfuric Acid Mist	lb/hr	0.83	0.79	0.77	NA	0.73	NA	NA	NA	NA	NA
50 Percent Load											
Temperature (°F)		175	178	175	NA	182	NA	NA	NA	NA	NA
Velocity (ft/sec)		39.1	38.4	37.4	NA	36.9	NA	NA	NA	NA	NA
Maximum Hourly Emissions per Unit											
SO_2	lb/hr	6.6	6.4	6.2	NA	5.9	NA	NA	NA	NA	NA
PM/PM_{10}	lb/hr	10.3	10.3	10.2	NA	10.2	NA	NA	NA	NA	NA
NO_x	lb/hr	10.8	10.4	10.1	NA	9.6	NA	NA	NA	NA	NA
CO	lb/hr	20.1	19.5	19.0	NA	18.3	NA	NA	NA	NA	NA
VOC (as methane)	lb/hr	1.9	1.9	1.8	NA	1.7	NA	NA	NA	NA	NA
Sulfuric Acid Mist	lb/hr	0.66	0.64	0.62	NA	0.59	NA	NA	NA	NA	NA

[a] Refer to Appendix A for detailed information on basis of pollutant emission rates and operating data.
Duct firing is assumed for 100% operating load. No duct firing is assumed for loads less than 100%.

[b] Steam augmentation and inlet fogging.

Source: Golder, 2001.

Table 2-2. Stack, Operating, and Emission Data for the Combustion Turbines/HRSGs for Combined Cycle Operation-Distillate Fuel Oil Combustion

		Operating and Emission Data [a] for Ambient Temperarure			
		Combustion Turbine/ HRSG			
Parameter		35 °F	59 °F	75 °F	95 °F
CT/HRSG Stack Data (ft)					
Height		120	120	120	120
Diameter		19.0	19.0	19.0	19.0
100 Percent Load					
Temperature (°F)		297	295	294	294
Velocity (ft/sec)		73.6	70.2	67.7	64.5
Maximum Hourly Emissions per Unit					
SO_2	lb/hr	103.1	98.6	94.9	89.1
PM/PM_{10}	lb/hr	37.8	36.9	36.2	35.0
NO_x	lb/hr	95.4	91.2	87.7	82.3
CO	lb/hr	68.1	64.7	62.1	58.9
VOC (as methane)	lb/hr	7.6	7.3	7.0	6.7
Lead	lb/hr	0.03	0.03	0.02	0.02
Sulfuric Acid Mist	lb/hr	10.31	9.86	9.49	8.91
75 Percent Load					
Temperature (°F)		271	274	276	278
Velocity (ft/sec)		55.6	54.3	53.3	51.4
Maximum Hourly Emissions per Unit					
SO_2	lb/hr	82.0	78.8	76.3	72.2
PM/PM_{10}	lb/hr	33.6	32.9	32.4	31.6
NO_x	lb/hr	75.0	72.2	69.9	66.1
CO	lb/hr	53.5	51.7	50.5	48.3
VOC (as methane)	lb/hr	6.0	5.8	5.7	5.5
Lead	lb/hr	0.02	0.02	0.02	0.02
Sulfuric Acid Mist	lb/hr	8.20	7.88	7.63	7.22
50 Percent Load					
Temperature (°F)		256	259	264	268
Velocity (ft/sec)		44.6	44.0	43.5	42.6
Maximum Hourly Emissions per Unit					
SO_2	lb/hr	64.7	62.6	60.8	57.7
PM/PM_{10}	lb/hr	30.1	29.7	29.3	28.7
NO_x	lb/hr	58.7	56.8	55.1	52.3
CO	lb/hr	44.3	43.2	42.3	41.0
VOC (as methane)	lb/hr	4.9	4.8	4.7	4.6
Lead	lb/hr	0.02	0.02	0.02	0.01
Sulfuric Acid Mist	lb/hr	6.47	6.26	6.08	5.77

[a] Refer to Appendix A for detailed information on basis of pollutant emission rates and operating data.

Source: Golder, 2001.

Table 2-3. Stack, Operating, and Emission Data for the Combustion Turbines for Simple Cycle Operation-Natural Gas Combustion

		Operating and Emission Data[a] for Ambient Temperarure Combustion Turbine				
Parameter		35 °F	59 °F	75 °F	80 °F[b]	95 °F
CT/Bypass Stack Data (ft)						
Height		80	80	80	80	80
Diameter		22.0	22.0	22.0	22.0	22.0
100 Percent Load						
Temperature (°F)		1,095	1,116	1,128	1,125	1,143
Velocity (ft/sec)		107.9	104.8	102.2	103.0	98.7
Maximum Hourly Emissions per Unit						
SO_2	lb/hr	10.2	9.8	9.4	9.5	8.9
PM/PM_{10}	lb/hr	9.0	9.0	9.0	9.0	9.0
NO_x	lb/hr	61.3	58.7	56.3	76.2	53.1
CO	lb/hr	28.6	27.5	26.6	45.0	25.5
VOC (as methane)	lb/hr	2.9	2.7	2.6	2.6	2.5
Sulfuric Acid Mist	lb/hr	1.02	0.98	0.94	0.95	0.89
75 Percent Load						
Temperature (°F)		1,122	1,139	1,153	NA	1,170
Velocity (ft/sec)		88.2	86.7	85.1	NA	83.0
Maximum Hourly Emissions per Unit						
SO_2	lb/hr	8.3	7.9	7.7	NA	7.3
PM/PM_{10}	lb/hr	9.0	9.0	9.0	NA	9.0
NO_x	lb/hr	48.9	47.1	45.4	NA	43.1
CO	lb/hr	24.4	23.5	22.7	NA	21.7
VOC (as methane)	lb/hr	2.3	2.2	2.2	NA	2.1
Sulfuric Acid Mist	lb/hr	0.83	0.79	0.77	NA	0.73
50 Percent Load						
Temperature (°F)		1,168	1,184	1,195	NA	1,200
Velocity (ft/sec)		74.8	73.9	72.7	NA	71.1
Maximum Hourly Emissions per Unit						
SO_2	lb/hr	6.6	6.4	6.2	NA	5.9
PM/PM_{10}	lb/hr	9.0	9.0	9.0	NA	9.0
NO_x	lb/hr	38.7	37.5	36.2	NA	34.5
CO	lb/hr	20.1	19.5	19.0	NA	18.3
VOC (as methane)	lb/hr	1.9	1.9	1.8	NA	1.7
Sulfuric Acid Mist	lb/hr	0.66	0.64	0.62	NA	0.59

[a] Refer to Appendix A for detailed information on basis of pollutant emission rates and operating data.

[b] Steam augmentation and inlet fogging.

Source: Golder, 2001.

Table 2-4. Stack, Operating, and Emission Data for the Combustion Turbines for Simple Cycle Operation-Distillate Fuel Oil Combustion

		Operating and Emission Data [a] for Ambient Temperarure			
		Combustion Turbine			
Parameter		35 °F	59 °F	75 °F	95 °F
CT/Bypass Stack Data (ft)					
Height		80	80	80	80
Diameter		22.0	22.0	22.0	22.0
100 Percent Load					
Temperature (°F)		1,074	1,098	1,113	1,131
Velocity (ft/sec)		111.3	108.0	105.4	101.5
Maximum Hourly Emissions per Unit					
SO_2	lb/hr	103.1	98.6	94.9	89.1
PM/PM_{10}	lb/hr	17.0	17.0	17.0	17.0
NO_x	lb/hr	333.8	319.2	306.8	288.2
CO	lb/hr	68.1	64.7	62.1	58.9
VOC (as methane)	lb/hr	7.6	7.3	7.0	6.7
Lead	lb/hr	0.03	0.03	0.02	0.02
Sulfuric Acid Mist	lb/hr	10.31	9.86	9.49	8.91
75 Percent Load					
Temperature (°F)		1,121	1,137	1,149	1,166
Velocity (ft/sec)		89.7	88.1	87.0	84.6
Maximum Hourly Emissions per Unit					
SO_2	lb/hr	82.0	78.8	76.3	72.2
PM/PM_{10}	lb/hr	17.0	17.0	17.0	17.0
NO_x	lb/hr	262.6	252.6	244.5	231.2
CO	lb/hr	53.5	51.7	50.5	48.3
VOC (as methane)	lb/hr	6.0	5.8	5.7	5.5
Lead	lb/hr	0.02	0.02	0.02	0.02
Sulfuric Acid Mist	lb/hr	8.20	7.88	7.63	7.22
50 Percent Load					
Temperature (°F)		1,168	1,182	1,193	1,200
Velocity (ft/sec)		75.7	74.9	74.2	72.6
Maximum Hourly Emissions per Unit					
SO_2	lb/hr	64.7	62.6	60.8	57.7
PM/PM_{10}	lb/hr	17.0	17.0	17.0	17.0
NO_x	lb/hr	205.6	198.9	192.9	183.2
CO	lb/hr	44.3	43.2	42.3	41.0
VOC (as methane)	lb/hr	4.9	4.8	4.7	4.6
Lead	lb/hr	0.02	0.02	0.02	0.01
Sulfuric Acid Mist	lb/hr	6.47	6.26	6.08	5.77

[a] Refer to Appendix A for detailed information on basis of pollutant emission rates and operating data.

Source: Golder, 2001.

Table 2-5. Summary of Maximum Potential Annual Emissions for the Combustion Turbines/HRSG for Combined and Simple Cycle Operations

Operating Scenario	Maximum Emissions (tons/year) based on hours for: Year 1			Year 2	
CC/ NG 100 % Load	0	0	0	5,380	4,480
CC/ DB /NG100 % Load	0	0	0	2,880	2,880
CC/ DB&PA/NG100 % Load	0	0	0	0	400
CC/ OIL 100 % Load	0	0	0	500	0
SC/ NG 100% Load	3,390	2,890	2,890	0	500
SC/ NG HPM100% Load	0	0	60	0	0
SC/ OIL100% Load	0	500	440	0	500
TOTAL	3,390	3,390	3,390	8,760	8,760

Pollutant	Maximum Hourly Emissions (lb/hr)[a] Combined Cycle (CC) Fuel: NG Load: 100%	CC NG 100% w/DB	CC NG 100% w/DB & PA	CC Oil 100%	Simple Cycle (SC) NG 100%	SC NG HPM	SC Oil 100%	Year 1	Year 1	Year 1	Year 2	Year 2
One Combustion Turbine												
SO_2	9.80	12.8	12.5	98.6	9.80	10.3	98.6	16.6	38.8	36.2	69.5	70.0
PM/PM_{10}	11.0	17.1	17.0	36.93	9.00	9.00	17.0	15.3	17.3	17.0	63.4	59.1
NO_x	16.3	23.6	22.1	91.20	58.7	101	319	99.4	164.6	158.0	100.6	169.4
CO	27.5	71.5	89.0	64.65	27.5	48.0	64.7	46.6	55.9	55.4	193.1	205.4
VOC (as methane)	2.74	11.5	11.4	7.28	2.74	2.75	7.28	4.6	5.8	5.6	25.8	27.6
Sulfuric Acid Mist	0.98	1.59	1.56	9.86	0.98	1.03	9.86	1.7	3.9	3.6	7.4	7.5
HAPs	0.66	0.86	0.84	2.47	0.66	0.69	2.47	1.1	1.6	1.5	3.6	3.7
Lead	0.00	0.00	0.00	0.025	0.00	0.00	0.025	0.0000	0.0063	0.0056	0.0063	0.0063
Four Combustion Turbines												
SO_2	39.2	51.3	50.2	394	39.2	41.2	394	66	155	145	278	280
PM/PM_{10}	43.9	68.4	68.1	148	36.0	36.0	68.0	61.0	69.0	68.1	254	236
NO_x	65.2	94.5	88.3	365	235	405	1277	398	658	632	403	678
CO	110.0	286	356	259	110.0	192	259	186	224	222	772	822
VOC (as methane)	10.96	46.2	45.8	29.1	10.96	10.98	29.1	18.6	23.1	22.6	103.2	110.2
Sulfuric Acid Mist	3.92	6.35	6.23	39.4	3.92	4.12	39.4	6.6	15.5	14.5	29.5	30.0
HAPs	2.63	3.45	3.37	9.89	2.63	2.76	9.89	4.46	6.27	6.06	14.5	14.7
Lead	0.00	0.00	0.00	0.101	0.00	0.00	0.101	0.000	0.025	0.022	0.025	0.025

[a] Based on 59 °F ambient inlet air temperature except for power augmentation at 80 °F .

Table 2-6. Performance, Stack Parameters and Emissions for Existing and Proposed Natural Gas Fuel Heaters

	Natural Gas Heaters	
Performance[a]		
	1st Year of Operation	Year 2+ of Operation
Fuel Usage (scf/hr-gas)	23,218	23,218
Heat Input (mmBtu/hr-HHV)	23.71	23.71
Hours per Year	3,390	1,000
Maximum Fuel Usage (mmscf/yr)	78.71	23.22
Number of Units	4	4
Stack Parameters		
Diameter (ft)	1.5	1.5
Height (ft)	30	30
Temperature (°F)	713	713
Velocity (ft/sec)	55	55
Flow (acfm)	11,736	11,736
Emissions		
SO_2 -Basis (grains S/100 scf-gas; %S diesel)[b]	2	2
(lb/hr)	0.133	0.133
(tpy) - one unit	0.225	0.066
(tpy) - maximum[a]	0.90	0.27
NO_x - (lb/mmBtu)[c]	0.100	0.100
(lb/hr)	2.36	2.36
(tpy)	4.0	1.180
(tpy) - maximum[a]	16.0	4.7
CO - (lb/mmBtu)[c]	0.075	0.075
(lb/hr)	1.79	1.79
(tpy)	3.03	0.895
(tpy) - maximum[a]	12.1	3.6
VOC - (lb/mmBtu)[c]	0.004	0.004
(lb/hr)	0.102	0.102
(tpy)	0.173	0.051
(tpy) - maximum[a]	0.69	0.20
PM/PM10 - ($lb/10^6 ft^3$)[d]	6.20	6.20
(lb/hr)	0.144	0.144
(tpy)	0.244	0.072
(tpy) - maximum[a]	0.98	0.29

[a] For total number of units.

[b] Typical maximum for pipeline natural gas.

[c] Vendor information (GasTech)

[d] EPA, AP-42 Table 1.4-2 Filterable PM; higher factor used for small heater; Table 3.3-1 PM_{10}.

Table 2-7. Physical, Performance and Emissions Data for the Mechanical Draft Cooling Tower

Parameter	Martin 4 x 1 Typical
Physical Data	
Number of Cells	18
Deck Dimensions, ft	
Length	486
Width	108
Height	40
Stack Dimensions	
Height, ft	45
Stack Top Effective Inner Diameter, per cell, ft	38
Effective Diameter, all cells, ft	161.2
Performance Data	
Discharge Velocity, ft/min	1,222
Circulating Water Flow Rate (CWFR), gal/min	310,000
Design hot water temperature, °F	104
Design cold water temperature, °F	90
Heat Rejected, million Btu/hr	2,600
Design Air Flow Rate per cell, acfm	1,386,055
Liquid/ Gas (Air Flow) (L/G) Ratio	1.400
Hours of operation	8,760
Emission Data	
Drift Rate[a] (DR), percent	0.002
Total Dissolved Solids (TDS) Concentration [b] ,maximum ppm	5,000
Solution Drift [c] (SD), lb/hr	3,102
PM Drift [d,e] , lb/hr	15.51
tons/year	67.9
PM_{10} Drift	
PM_{10} Portion (percent) of PM Drift	30
PM_{10} Emissions, lb/hr	4.65
tons/year	20.4

Source: FPLE, November 19, 2001.

[a] Drift rate is the percent of circulating water

[b] TDS may range from 1000 to 9000 ppm. A TDS of 4000 results in maximum PM emissions (See paper titled "Calculation of Realistic PM10 Emissions from Cooling Towers" presented in Appendx A.

[c] Includes water and based on circulating water flow rate and drift rate (CWFR x DR x 8.34 lb/gal x 60 min/hr)

[d] PM calculated based on total dissolved solids and solution drift (TDS x SD)

[e] See paper titled "Calculating Realistic PM_{10} Emissions from Cooling Towers" presented in Appendix A.

Table 2-8. Summary of Maximum Potential Annual Emissions for the FPL Martin Unit 8 Combined Cycle Project

Pollutant	Annual Emissions (tons/year) Year 1: 4 CTs Simple Cycle	Year 1: 4 Natural Gas Fuel Heaters	Year 1: TOTAL	Year 2: 4 CTs/HRSGs with Duct Burners	Year 2: 4 Natural Gas Fuel Heaters	Year 2: Cooling Tower	Year 2: TOTAL	PSD Significant Emission Rate (tons/year)	PSD Review Required?
SO_2	155	0.35	156	280	0.27	NA	280	40	Yes
PM	69.0	0.38	69	254	0.29	67.9	322	25	Yes
PM_{10}	69.0	0.38	69	254	0.29	20.4	275	15	Yes
NOx	658	6.2	664	678	4.7	NA	683	40	Yes
CO	224	4.7	228	822	3.6	NA	826	100	Yes
VOC (as methane)	23.1	0.27	23	110.2	0.20	NA	110	40	Yes
Sulfuric Acid Mist	15.5	NA	15.5	30.0	Neg.	NA	30.0	7	Yes
Lead	0.025	NA	0.025	0.025	NA	NA	0.025	0.6	No

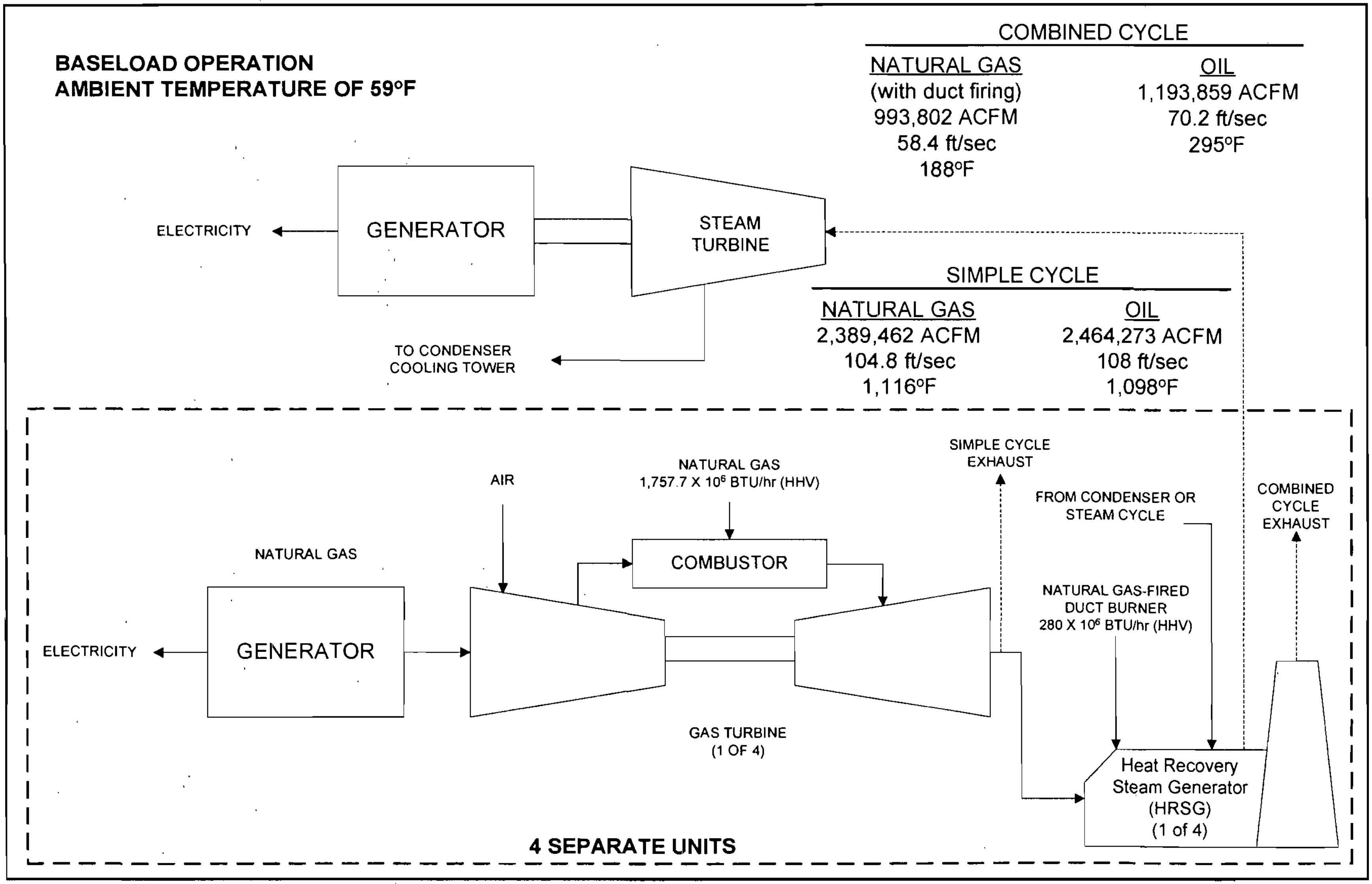

Figure 2-1. Process Flow Diagram
Baseload Operation, Ambient Temperature of 59°F

Process Flow Legend
Solid/Liquid →
Gas →
Steam →

FPL
Martin Unit 8

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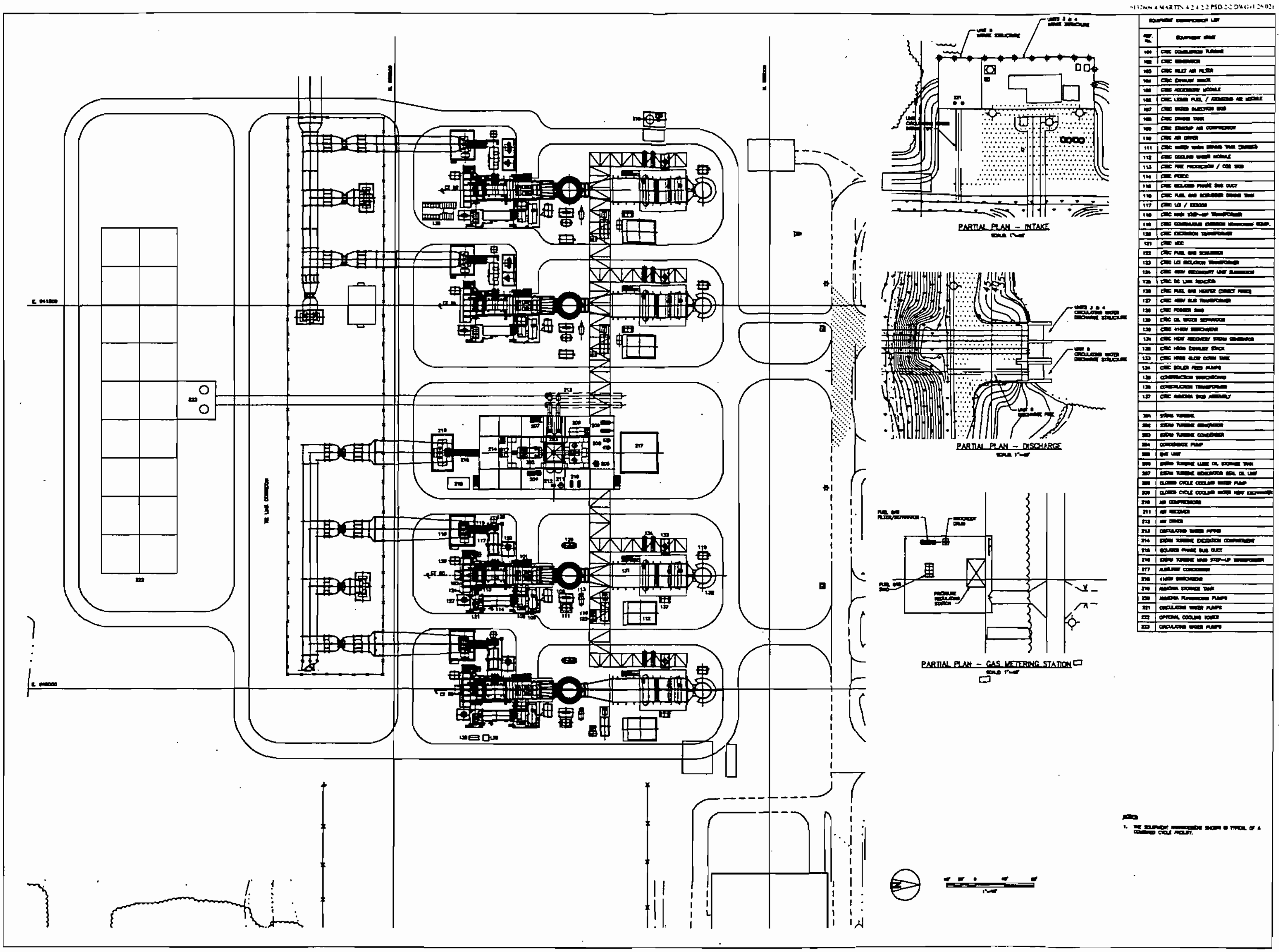

Figure 2-2. Overall Site Arrangement

Source: Black & Veatch, 2001; FPL, 2001; and Golder, 2001.

FPL
Martin Unit 8

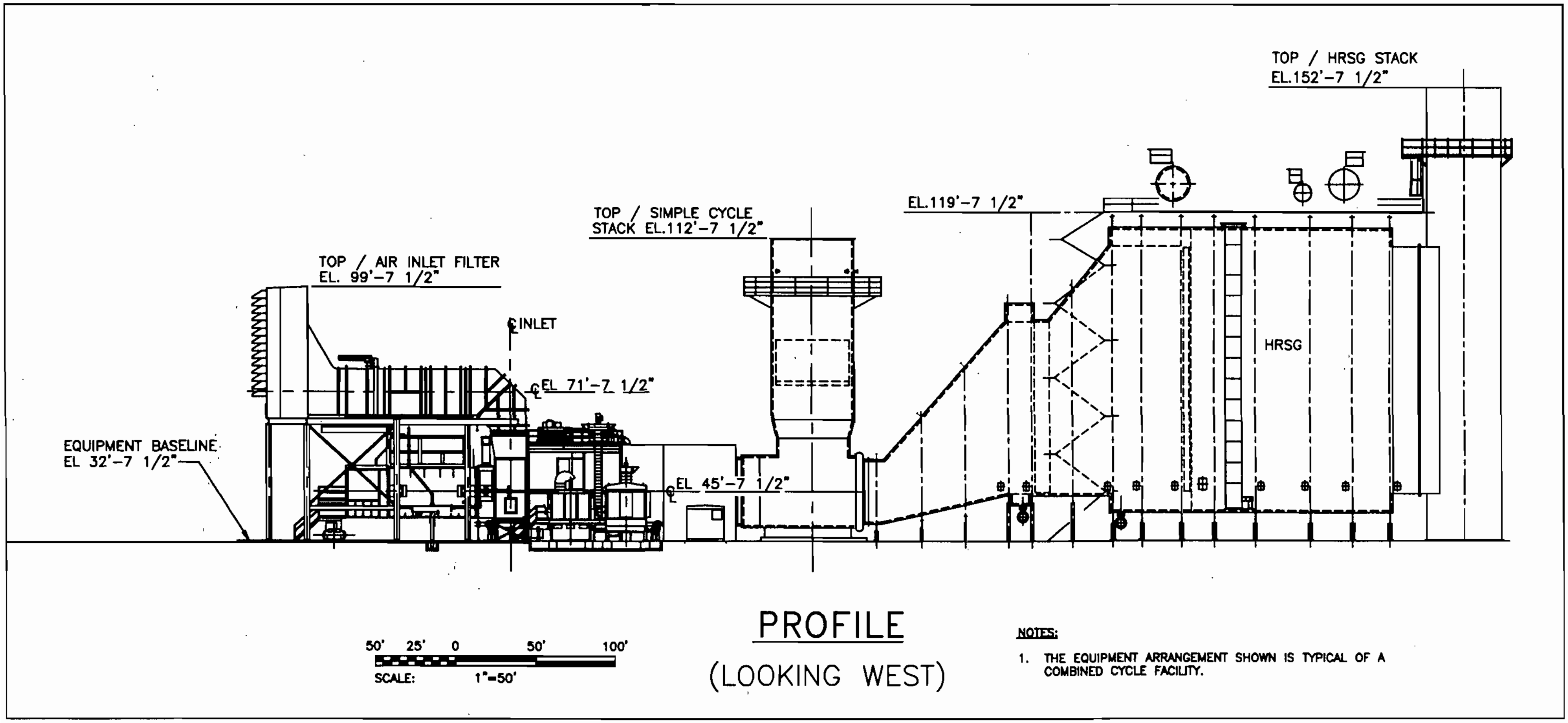

Figure 2-3. Profile of Combustion Turbine and Heat Recovery Steam Generator

Source: Block & Veatch, 2001; FPL, 2001; and Golder, 2001.

FPL
Martin Unit 8

3.0 AIR QUALITY REVIEW REQUIREMENTS AND APPLICABILITY

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

3.1 NATIONAL AND STATE AAQS

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

3.2 PSD REQUIREMENTS

3.2.1 GENERAL REQUIREMENTS

Under federal and State of Florida PSD review requirements, all major new or modified sources of air pollutants regulated under the Clean Air Act (CAA) must be reviewed and a pre-construction permit issued. Florida's State Implementation Plan (SIP), which contains PSD regulations, has been approved by EPA; therefore, PSD approval authority has been granted to FDEP.

A "major facility" is defined as any 1 of 28 named source categories that have the potential to emit 100 tons per year (TPY) or more or any other stationary facility that has the potential to emit 250 TPY or more of any pollutant regulated under CAA. "Potential to emit" means the capability, at maximum design capacity, to emit a pollutant after the application of control equipment.

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

EPA has promulgated regulations providing that certain increases above an air quality baseline concentration level of SO_2, PM_{10}, and NO_2 concentrations that would constitute significant deterioration. The EPA class designations and allowable PSD increments are presented in Table 3-1.

The State of Florida has adopted the EPA class designations and allowable PSD increments for SO_2, PM_{10}, and NO_2.

PSD review is used to determine whether significant air quality deterioration will result from the new or modified facility. Federal PSD requirements are contained in 40 CFR 52.21, *Prevention of Significant Deterioration of Air Quality*. The State of Florida's PSD regulations are found in Rule 62-212.400 F.A.C. Major facilities and major modifications are required to undergo the following analysis related to PSD for each pollutant emitted in significant amounts:

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

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

3.2.2 CONTROL TECHNOLOGY REVIEW

The control technology review requirements of the federal and state PSD regulations require that all applicable federal and state emission-limiting standards be met, and that BACT be applied to control emissions from the source (Rule 62-212.400, F.A.C.). The BACT requirements are applicable to all regulated pollutants for which the increase in emissions from the facility or modification exceeds the significant emission rate (see Table 3-2).

BACT is defined in 52.21 (b)(12) and Rule 62-210.200(38), F.A.C., as:

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

> the application of measurement methodology to a particular part of a source or facility would make the imposition of an emission standard infeasible, a design, equipment, work practice, operational standard or combination thereof, may be prescribed instead to satisfy the requirement for the application of BACT. Such standard shall, to the degree possible, set forth the emissions reductions achievable by implementation of such design, equipment, work practice, or operation and shall provide for compliance by means which achieve equivalent results.

BACT was promulgated within the framework of the PSD requirements in the 1977 amendments of the CAA [Public Law 95-95; Part C, Section 165(a)(4)]. The primary purpose of BACT is to optimize consumption of PSD air quality increments and thereby enlarge the potential for future economic growth without significantly degrading air quality (EPA, 1978; 1980). Guidelines for the evaluation of BACT can be found in *Guidelines for Determining Best Available Control Technology (BACT)* (EPA, 1978) and in the *PSD Workshop Manual* (EPA, 1980). These guidelines were promulgated by EPA to provide a consistent approach to BACT and to ensure that the impacts of alternative emission control systems are measured by the same set of parameters. In addition, through implementation of these guidelines, BACT in one area may not be identical to BACT in another area. According to EPA (1980), "BACT analyses for the same types of emissions unit and the same pollutants in different locations or situations may determine that different control strategies should be applied to the different sites, depending on site-specific factors. Therefore, BACT analyses must be conducted on a case-by-case basis."

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

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

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

3.2.3 SOURCE IMPACT ANALYSIS

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

The EPA has proposed significant impact levels for Class I areas. The levels are as follows:

Pollutant	Averaging Time	Proposed EPA PSD Class I Significant Impact Levels ($\mu g/m^3$)
SO_2	3-hour	1
	24-hour	0.2
	Annual	0.1
PM_{10}	24-hour	0.3
	Annual	0.2
NO_2	Annual	0.1

[a] $\mu g/m^3$ = micrograms per cubic meter.

Although these levels have not been officially promulgated as part of the PSD review process and may not be binding for states in performing PSD reviews, the proposed levels serve as a guideline in assessing a source's impact in a Class I area. The EPA action to incorporate Class I significant impact levels in the PSD process is part of implementing NSR provisions of the 1990 CAA Amendments. Because the process of developing the regulations will be lengthy, EPA believes that the proposed rules concerning the significant impact levels is appropriate to assist states in implementing the PSD permit process. The FDEP has accepted the use of these significant impact levels.

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

The term "baseline concentration" evolves from federal and state PSD regulations and refers to a concentration level corresponding to a specified baseline date and certain additional baseline sources. By definition, in the PSD regulations as amended August 7, 1980, baseline concentration means the ambient concentration level that exists in the baseline area at the time of the applicable baseline date.

A baseline concentration is determined for each pollutant for which a baseline date is established and includes:

1. The actual emissions representative of facilities in existence on the applicable baseline date; and
2. The allowable emissions of major stationary facilities that commenced construction before January 6, 1975, for SO_2 and PM(TSP) concentrations or February 8, 1988, for NO_2 concentrations, but that were not in operation by the applicable baseline date.

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

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

In reference to the baseline concentration, the term "baseline date" actually includes three different dates:

1. The major facility baseline date, which is January 6, 1975, in the cases of SO_2 and PM(TSP) and February 8, 1988, in the case of NO_2.
2. The minor facility baseline date, which is the earliest date after the trigger date on which a major stationary facility or major modification subject to PSD regulations submits a complete PSD application.
3. The trigger date, which is August 7, 1977, for SO_2 and PM(TSP) and February 8, 1988, for NO_2.

The minor source baseline date for SO_2 and PM(TSP) has been set as December 27, 1977, for the entire State of Florida (Rules 62-204.200(22); 204.360, F.A.C.). The minor source baseline for NO_2 has been set as March 28, 1988 (Rule 62-204.200(22);204.360, F.A.C). It should be noted that references to PM(TSP) are also applicable to PM_{10}.

3.2.4 AIR QUALITY MONITORING REQUIREMENTS

In accordance with requirements of 40 CFR 52.21(m) and Rule 62-212.400(5)(f), F.A.C., any application for a PSD permit must contain an analysis of continuous ambient air quality data in the area affected by the proposed major stationary facility or major modification. For a new major facility, the affected pollutants are those that the facility potentially would emit in significant amounts. For a major modification, the pollutants are those for which the net emissions increase exceeds the significant emission rate (see Table 3-2).

Ambient air monitoring for a period of up to 1 year generally is appropriate to satisfy the PSD monitoring requirements. Data for a minimum of 4 months are required. Existing data from the vicinity of the proposed source may be used, if the data meet certain quality assurance requirements; otherwise, additional data may need to be gathered. Guidance in designing a PSD monitoring network is provided in *Ambient Monitoring Guidelines for Prevention of Significant Deterioration* (EPA, 1987a).

The regulations include an exemption that excludes or limits the pollutants for which an air quality analysis must be conducted. This exemption states that a proposed major stationary facility or major modification is exempt from the monitoring requirements with respect to a particular pollutant, if the emissions increase of the pollutant from the facility or modification would cause, in any area, air quality impacts less than the *de minimis* levels presented in Table 3-2 (Rule 62-212.400-3, F.A.C.). If a facility predicted impacts are less than the *de minimis* levels, therefore, preconstruction monitoring will not be required.

3.2.5 SOURCE INFORMATION/GEP STACK HEIGHT

Source information must be provided to adequately describe the proposed facility. The general type of information required for this facility is presented in Section 2.0.

The 1977 CAA Amendments require that the degree of emission limitation required for control of any pollutant can not be affected by a stack height that exceeds GEP or any other dispersion technique. On July 8, 1985, EPA promulgated final stack height regulations (EPA, 1985a). Identical regulations have been adopted by FDEP (Rule 62-210.550, F.A.C.). GEP stack height is defined as the highest of:

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

   Hg = H + 1.5L

   where: Hg = GEP stack height,

   H = Height of the structure or nearby structure, and

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

"Nearby" is defined as a distance up to 5 times the lesser of the height or width dimensions of a structure or terrain feature, but not greater than 0.8 km. Although GEP stack height regulations require that the stack height used in modeling for determining compliance with AAQS and PSD increments not exceed the GEP stack height, the actual stack height may be greater.

The stack height regulations also allow increased GEP stack height beyond that resulting from the above formula in cases where plume impaction occurs. Plume impaction is defined as concentrations measured or predicted to occur when the plume interacts with elevated terrain. Elevated terrain is defined as terrain that exceeds the height calculated by the GEP stack height formula.

3.2.6 ADDITIONAL IMPACT ANALYSIS

In addition to air quality impact analyses, federal and State of Florida PSD regulations require analyses of the impairment to visibility and the impacts on soils and vegetation that would occur as a result of the proposed source [40 CFR 52.21(o); Rule 62-212.400(5)(e), F.A.C.]. These analyses are to be conducted primarily for PSD Class I areas. Impacts as a result of general commercial, residential, industrial, and other growth associated with the source also must be addressed. These analyses are required for each pollutant emitted in significant amounts (see Table 3-2).

3.3 NONATTAINMENT RULES

Based on the current nonattainment provisions (Rule 62-212.500, F.A.C.), all major new facilities and modifications to existing major facilities, located in a nonattainment area, must undergo nonattainment review. A new major facility is required to undergo this review, if the proposed pieces of equipment have the potential to emit 100 TPY or more of the nonattainment pollutant. A major modification at a major facility is required to undergo review, if it results in a significant net emission increase of 40 TPY or more of the nonattainment pollutant or if the modification is major (i.e., 100 TPY or more).

For major facilities or major modifications that locate in an attainment or unclassifiable area, the nonattainment review procedures apply if the source or modification is located within the area of influence of a nonattainment area. The area of influence is defined as an area that is outside the boundary of a nonattainment area but within the locus of all points that are 50 km outside the boundary of the nonattainment area. Based on Rule 62-2.500(2)(c)2.a., F.A.C., all VOC sources that are located within an area of influence are exempt from the provisions of NSR for nonattainment areas. Sources that emit other nonattainment pollutants and are located within the area of influence are subject to nonattainment review unless the maximum allowable emissions from the proposed source do not have a significant impact within the nonattainment area.

3.4 EMISSION STANDARDS

3.4.1 NEW SOURCE PERFORMANCE STANDARDS

The NSPS are a set of national emission standards that apply to specific categories of new sources. As stated in the 1977 CAA Amendments, these standards "shall reflect the degree of emission limitation and the percentage reduction achievable through application of the best technological system of continuous emission reduction the Administrator determines has been adequately demonstrated."

The proposed Project will be subject to one or more NSPS. The CTs will be subject to 40 CFR Part 60, Subpart GG, the duct burners will be subject to 40 CFR Part 60, Subpart Da, and the fuel oil storage tanks (2.1 million gallon capacity each) will be subject to 40 CFR Part 60, Subpart Kb.

Combustion Turbine

The CTs will be subject to emission limitations covered under Subpart GG, which limits NO_x and SO_2 emissions from all stationary CTs with a heat input at peak load equal to 10.7 gigajoules per hour (10 MMBtu/hr), based on the lower heating value of the fuel fired.

NO_x emissions are limited to 75 ppmvd corrected to 15-percent O_2 and heat rate, while SO_2 emissions are limited to using a fuel with a sulfur content of 0.8 percent. In addition to emission limitations, there are requirements for notifying, record keeping, reporting, performance testing, and monitoring. These are summarized below:

40 CFR 60.7 Notification and Record Keeping

(a)(1) Notification of the date of construction - 30 days after such date.

(a)(3) Notification of actual date of initial start-up - within 15 days after such date.

(a)(5) Notification of date which demonstrates CEM - not less than 30 days prior to date.

60.7 (b) Maintain records of all start-ups, shutdowns, and malfunctions.

(c) Excess emissions reports – semi-annually by the 30th day following six-month period. (required even if no excess emissions occur)

(d) Maintain file of all measurements for 2 years.

60.8 Performance Tests

(a) must be performed within 60 days after achieving maximum production rate but no later than 180 days after initial start-up.

(d) Notification of Performance tests at least 30 days prior to them occurring.

40 CFR Subpart GG

60.334 Monitoring of Operations

(a) continuous monitoring system required for water-to-fuel ratio to meet NSPS; system must be accurate within ±5 percent.

(b) Monitor sulfur and nitrogen content of fuel.

Oil - (1): each occasion that fuel is transferred to bulk storage tank.

No intermediate storage – (2): daily monitoring required.

Duct Burner

The applicable NSPS is 40 CFR Part 60, Subpart Da, Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978. This subpart applies to electric utility combined-cycle combustion turbines that are capable of combusting more than 250-mmBtu/hr heat input of fossil fuel in the steam generator. Only emissions resulting from combustion of fuels in the steam-generating unit are subject to this regulation.

The applicable NO_x and PM NSPS limits are 1.6 lb/MW (gross) and 0.03 lb/MMBtu, respectively, for the gas-fired duct burners being considered for the Project. The proposed NO_x and PM emission limits of 0.08 lb/MW and 0.008 lb/MMBtu, respectively, for the Project will be much lower than the NSPS.

Fuel Oil Storage Tank

The applicable NSPS is 40 CFR Part 60, Subpart Kb--Standards of Performance for Volatile Organic Liquid Storage Vessels (including petroleum liquid storage vessels for which construction, reconstruction, or modification commenced after July 23, 1984). The storage tanks will contain distillate fuel oil, a volatile organic liquid as defined in Subpart Kb. There are no emission limiting or control requirements under Subpart Kb for the use of distillate fuel oil. The facility, however, must perform record keeping for the type of organic liquid in the tank. These storage tanks were previously approved with the permitting of Martin Units 3 and 4.

3.4.2 FLORIDA RULES

The FDEP regulations for new stationary sources are covered in the F.A.C. The FDEP has adopted the EPA NSPS by reference in Rule 62-204.800(7): subsection (b)39 for stationary gas turbines Substation (6)(2) for the duct burners, and subsection (b)16 for volatile organic liquid storage vessels. Therefore, the facility is required to meet the same emissions, performance testings, monitoring, reporting, and record keeping as those described in Section 3.4.1. FDEP has authority for implementing NSPS requirements in Florida.

3.4.3 FLORIDA AIR PERMITTING REQUIREMENTS

The FDEP regulations require any new source to obtain an air permit prior to construction. Major new sources must meet the appropriate PSD and nonattainment requirements as discussed previously. Required permits and approvals for air pollution sources include NSR for nonattainment areas, PSD, NSPS, National Emission Standards for Hazardous Air Pollutants (NESHAP), Permit to Construct, and Permit to Operate. The requirements for construction permits and approvals are contained in Rules 62-4.030, 62-4.050, 62-4.210, 62-210.300(1), and 62-212.400 F.A.C. Specific emission standards are set forth in Chapter 62-296, F.A.C.

3.4.4 LOCAL AIR REGULATIONS

Martin County has not implemented air regulations or ordinances.

3.5 SOURCE APPLICABILITY

3.5.1 AREA CLASSIFICATION

The facility site is located in Martin County, which has been designated by EPA and FDEP as an attainment area (includes unclassifiable) for all criteria pollutants. Martin County and surrounding counties are designated as PSD Class II areas for SO_2, PM(TSP), and NO_2. The nearest Class I area is the Everglades National Park (NP) located about 144 km (90 miles) to the south-southwest of the facility site.

3.5.2 PSD REVIEW

Pollutant Applicability

The Martin Plant is considered to be a major facility because the emissions of several regulated pollutants are estimated to exceed 100 TPY and the emissions units are one of the 28 listed categories. The addition of the Project at the Martin Plant is a modification under the PSD rules and PSD review is required for any pollutant for which the emissions exceed the PSD significant emission rates. As shown in Table 3-3, potential emissions from the proposed Project will trigger PSD for PM(TSP), PM_{10}, SO_2, NO_x, CO, VOC and sulfuric acid mist. Impacts for these pollutants that are predicted to be above the significant impact levels require a modeling analysis incorporating the impacts from other sources is required. (Note: EPA no longer requires PSD review for hazardous air pollutants (HAPs) from PSD review. The pollutants vinyl chloride, asbestos, and beryllium are no longer evaluated in PSD review because they are addressed through the NESHAP program.)

As part of the PSD review, a PSD Class I increment analysis is required if the proposed facility's impacts are greater than the proposed EPA Class I significant impact levels. The nearest Class I area to the plant site is about 144 km from the site and a PSD Class I increment analysis and an evaluation of impacts to AQRVs is required.

Emission Standards

The applicable NSPS for the CTs is 40 CFR Part 60, Subpart GG. The proposed emissions for the turbines will be well below the specified limits (see Section 4.0).

The applicable NSPS for the duct burners is 40 CFR Part 60, Subpart Da. The proposed emissions for the duct burners will be well below the specified limits (see Section 4.0).

The fuel oil storage tanks will have a maximum storage capacity of 2.1 million gallons of No. 2 fuel oil each. Since the storage tank has a capacity greater than 40 cubic meters (m^3)(approximately 10,568 gallons), the applicable NSPS is 40 CFR Part 60, Subpart Kb. Each storage tank will contain distillate fuel oil, a volatile organic liquid as defined in Subpart Kb, with a true vapor pressure of 0.022 pound per square inch (psi) at 100°F. Because the fuel oil is expected to have a maximum true vapor pressure of less than 3.5 kilopascals (kPa) or 0.51 psi, only the minor monitoring of operating requirements specified in 40 CFR 60 116b(a) and (b) will apply.

Ambient Monitoring

Based on the estimated pollutant emissions from the proposed plant (see Table 3-4), a pre-construction ambient monitoring analysis is required for PM_{10}, SO_2 , NO_2, CO, and O_3 (based on VOC emissions). If the net increase in impact of other pollutants is less than the applicable *de minimis* monitoring concentration (100 TPY in the case of VOC), then an exemption from the pre-construction ambient monitoring requirement is available by Rule 62-212.400(3)(e) F.A.C. In addition, if an acceptable ambient monitoring method for the pollutant has not been established by EPA, monitoring is not required.

As shown in Table 3-4, the proposed plant's impacts are predicted to be below the applicable *de minimis* monitoring concentration levels for all pollutants. Therefore, pre-construction monitoring is not required to be submitted for this facility. The emissions of VOC are above the *de minimis* monitoring threshold. The monitoring analysis is presented in Section 5.0.

GEP Stack Height Impact Analysis

The GEP stack height regulations allow any stack to be at least 65 m [213 feet (ft)] high. The stacks for the Project will be 120 ft for the HRSG stacks and 80 ft for the simple cycle stacks. These stack heights do not exceed the GEP stack height. However, as discussed in Section 6.0, Air Quality Modeling Approach, since the stack height is less than GEP, building downwash effects must be considered in the modeling analysis. As a result, the potential for downwash of the CT emissions caused by nearby structures are included in the modeling analysis.

3.5.3 NONATTAINMENT REVIEW

The facility site is located in Martin County, which is classified as an attainment area for all criteria pollutants. Therefore, nonattainment requirements are not applicable.

3.5.4 OTHER CLEAN AIR ACT REQUIREMENTS

The 1990 CAA Amendments established a program to reduce potential precursors of acidic deposition. The Acid Rain Program was delineated in Title IV of the CAA Amendments and required EPA to develop the program. EPA's final regulations were promulgated on January 11, 1993, and included permit provisions (40 CFR Part 72), allowance system (Part 73), continuous emission monitoring (Part 75), excess emission procedures (Part 77), and appeal procedures (Part 78).

EPA's Acid Rain Program applies to all existing and new utility units except those serving a generator less than 25 MW, existing simple cycle CTs, and certain non-utility facilities; units which fall under the program are referred to as affected units. The EPA regulations would be applicable to the proposed facility for the purposes for obtaining a permit and allowances, as well as emission monitoring. New units are required to obtain permits under the program by submitting a complete application 24 months before the date on which the unit commences operation (e.g., first fire).

The permit would require the units to hold SO_2 emission allowances. Emission limitations established in the Acid Rain Program are presumed to be less stringent than BACT or lowest achievable emission rate (LAER) for new units. An allowance is a market-based financial instrument that is equivalent to 1 ton of SO_2 emissions. Allowances can be sold, purchased, or traded.

Continuous emission monitoring (CEM) for SO_2 and NO_x is required for gas fired and oil fired affected units. When an SO_2 CEM is selected to monitor SO_2 mass emissions, a flow monitor is also required. Alternately, SO_2 emissions may be determined using procedures established in Appendix D, 40 CFR Part 75 (flow proportional oil sampling or manual daily oil sampling). CO_2 emissions must also be determined either through a CEM (e.g., as a diluent for NO_x monitoring) or calculation. Alternate procedures, test methods, and quality assurance/quality control (QA/QC) procedures for CEM are specified (Part 75, Appendices A through I). The acid rain CEM requirements including QA/QC procedures are, in general, more stringent than those specified in the NSPS for Subpart GG.

New units are required to meet the requirements by the later of January 1, 1995, or not later than 90 days after the unit commences commercial operation.

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

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

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

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

[b] Maximum concentrations are not to be exceeded.

[c] On July 18, 1997, EPA promulgated revised AAQS for particulate matter and ozone. For particulate matter, $PM_{2.5}$ standards were introduced with a 24-hour standard of 65 g/m^3 (3-year average of 98th percentile) and an annual standard of 15 g/m^3 (3-year average at community monitors). These standards are not yet applicable and have been challenged at the federal level.

[d] 0.08 ppm; achieved when 3-year average of 99th percentile is 0.08 ppm or less. The standard is not yet applicable and has been challenged at the federal level.

Sources: Federal Register, Vol. 43, No. 118, June 19, 1978.
40 CFR 50; 40 CFR 52.21.
Chapter 62-204, F.A.C.

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

Pollutant	Regulated Under	Significant Emission Rate (TPY)	*De Minimis* Monitoring Concentration[a] ($\mu g/m^3$)
Sulfur Dioxide	NAAQS, NSPS	40	13, 24-hour
Particulate Matter [PM(TSP)]	NSPS	25	10, 24-hour
Particulate Matter (PM_{10})	NAAQS	15	10, 24-hour
Nitrogen Dioxide	NAAQS, NSPS	40	14, annual
Carbon Monoxide	NAAQS, NSPS	100	575, 8-hour
Volatile Organic Compounds (Ozone)	NAAQS, NSPS	40	100 TPY[b]
Lead	NAAQS	0.6	0.1, 3-month
Sulfuric Acid Mist	NSPS	7	NM
Total Fluorides	NSPS	3	0.25, 24-hour
Total Reduced Sulfur	NSPS	10	10, 1-hour
Reduced Sulfur Compounds	NSPS	10	10, 1-hour
Hydrogen Sulfide	NSPS	10	0.2, 1-hour
Mercury	NESHAP	0.1	0.25, 24-hour

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

NAAQS = National Ambient Air Quality Standards.
NM = No ambient measurement method established; therefore, no *de minimis* concentration has been established.
NSPS = New Source Performance Standards.
NESHAP = National Emission Standards for Hazardous Air Pollutants.
g/m^3 = micrograms per cubic meter.

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

Sources: 40 CFR 52.21.
Rule 62-212.400

Table 3-3. Maximum Emissions Due to the Proposed Project Compared to the PSD Significant Emission Rates

Pollutant	Pollutant Emissions (TPY)		PSD Review
	Potential Emissions from Proposed Project[a]	Significant Emission Rate	
Sulfur Dioxide	280	40	Yes
Particulate Matter [PM(TSP)]	322	25	Yes
Particulate Matter (PM_{10})	275	15	Yes
Nitrogen Dioxide	683	40	Yes
Carbon Monoxide	826	100	Yes
Volatile Organic Compounds	110	40	Yes
Lead	0.025	0.6	No
Sulfuric Acid Mist	30.0	7	Yes
Total Fluorides	NEG	3	No
Total Reduced Sulfur	NEG	10	No
Reduced Sulfur Compounds	NEG	10	No
Hydrogen Sulfide	NEG	10	No
Mercury	$2.3\text{x}10^{-3}$	0.1	No

Note: NEG = Negligible.

[a] Based on emissions from operating at base load at 59°F:

1. Combined Cycle
   - 100-percent load, natural gas – 4,480 hours
   - 100-percent load with duct burners, natural gas – 2,880 hours
   - 100-percent load with duct burners and high power mode – 400 hours
2. Simple Cycle
   - 100-percent load, natural gas – 500 hours
   - 100-percent load, oil firing – 500 hours

Includes four natural gas heaters (see Table 2-6) and cooling tower (see Table 2-7).

Table 3-4. Predicted Net Increase in Impacts Due to the Proposed Project Compared to PSD *De Minimis* Monitoring Concentrations

	Concentration (µg/m³)		
	Predicted Increase in Impacts[a]		*De Minimis* Monitoring
Pollutant	4 on 1 CC	4 SC	Concentration
Sulfur Dioxide	8.64	0.84	13, 24-hour
Particulate Matter (PM_{10})	4.01	0.23	10, 24-hour
Nitrogen Dioxide	0.56	0.23	14, annual
Carbon Monoxide	16.2	1.42	575, 8-hour
Volatile Organic Compounds	110 TPY	22.6 TPY	100 TPY

Note: SC = simple cycle operation

CC = combined cycle operation

[a] See Section 6.0 for air dispersion modeling results.

4.0 CONTROL TECHNOLOGY REVIEW

4.1 APPLICABILITY

The PSD regulations require new major stationary sources to undergo a control technology review for each pollutant that may potentially be emitted above significant amounts. The control technology review requirements of the PSD regulations are applicable to emissions of NO_x, SO_2, CO, PM/PM_{10}, and sulfuric acid mist (see Section 3.0). The maximum potential annual emissions of these pollutants from the proposed "F" Class CTs are summarized in Table 2-5.

This section presents the applicable NSPS and the proposed BACT for these pollutants. The approach to the BACT analysis is based on the regulatory definitions of BACT, as well as consideration of EPA's current policy guidelines requiring a top-down approach. A BACT determination requires an analysis of the economic, environmental, and energy impacts of the proposed and alternative control technologies [see 40 CFR 52.21(b)(12)]. The analysis must, by definition, be specific to the Project (i.e., case by case).

4.2 NEW SOURCE PERFORMANCE STANDARDS

The applicable NSPS for CTs are codified in 40 CFR 60, Subpart GG and summarized in Appendix B. The applicable NSPS emission limit for NO_x is 75 parts per million by volume dry (ppmvd) corrected for heat rate and 15-percent O_2. For the CTs being considered for the Project, the NSPS emission limit for NO_x, with the NSPS heat rate correction, is over 100 parts per million (ppm) firing natural gas and distillate oil (corrected to 15-percent O_2 at a fuel-bound nitrogen content of 0.015 percent). The proposed NO_x emission limits for the Project in combined cycle mode will be 40 times lower than the NSPS when firing natural gas and 8 times lower than the NSPS when firing distillate oil.

The applicable NSPS for the duct burner are codified in 40 CFR 60, Subpart Da and is also summarized in Attachment B. The applicable NO_x emission limit is 1.6 lb/MW-hr. The combined CT and duct burner emissions rate with SCR of 2.5 ppmvd corrected to 15-percent O_2 is equivalent to about 0.08 lb/MW-hr or over 10 times lower than the applicable NSPS.

4.3 BEST AVAILABLE CONTROL TECHNOLOGY

4.3.1 OVERVIEW OF PROPOSED BACT

In recent permitting actions, BACT for heavy-duty industrial gas turbines has been determined. These decisions established emission rates that were achieved through the use of advanced DLN combustors and SCR for limiting emissions of NO_x, good combustion practices for minimizing CO and VOC emissions, and the use of clean fuels (natural gas) for control of other emissions, including PM_{10} and SO_2. The BACT proposed for the Project is consistent with these permits. The results of the BACT analysis have concluded the following controls as BACT for the Project operating in combined cycle mode.

1. The Project when in combined cycle operation will use state-of-the-art DLN combustion technology and SCR to achieve gas turbine exhaust NO_x levels of no greater than 2.5 ppmvd corrected to 15-percent O_2 when firing natural gas and 12 ppmvd corrected to 15-percent O_2 when firing. For the first year and limited operation in the future, the Project will operate in simple cycle mode. The simple cycle BACT emission rates for NO_x are 9 ppmvd corrected to 15-percent O_2 when firing gas and 42 ppmvd corrected to 15-percent O_2 when firing oil.
2. CO emissions when firing natural gas will be limited to 9 ppmvd at baseload to 50 percent load (simple and combined cycle) 24.5 ppmvd with duct firing (combined cycle) and 29.6 ppmvd with HPM and duct firing. When firing distillate oil CO will be limited to 20 ppmvd (simple and combined cycle).
3. Emission rates of PM_{10} and SO_2 will be limited using natural gas.

A summary of the emission rates proposed as BACT is presented in Table 4-1. Excess emissions proposed for the Project is addressed in Section 2.5.

4.3.2 NITROGEN OXIDES – COMBINED CYCLE

Technology Description

The BACT analysis was performed based on those available and feasible control technologies that can provide the maximum degree of emission reduction for NO_x emissions. An evaluation of the available and feasible control technologies determined that combustion along with SCR could provide the maximum degree of emission reduction. $SCONO_x$™ is commercially available but has not been demonstrated on "F" Class combustion turbines. Other available technologies such as NO_xOut, Thermal $DeNO_x$, NSCR, and XONON™ Combustion System were evaluated and determined to be technically infeasible or not commercially demonstrated for the Project. Appendix B presents a discussion of these NO_x control technologies and their feasibility for the Project.

DLN combustor technology has been offered and installed by manufacturers to reduce NO_x emissions by inhibiting thermal NO_x formation through premixing fuel and air prior to combustion and providing staged combustion to reduce flame temperatures. NO_x emissions from 25 ppmvd (corrected to 15-percent O_2) and less has been offered by manufacturers for advanced CTs. This technology prevents pollution since NO_x emissions are inhibited from forming. When firing distillate oil, NO_x is limited using water injection to 42 ppmvd (corrected to 15-percent O_2).

SCR is a post-combustion process where NO_x in the gas stream is reacted with ammonia in the presence of a catalyst to form nitrogen and water. It is available from vendors for combined cycle applications. The reaction occurs typically between 600°F and 750°F, which occur in combined cycle units in the HRSG. SCR has been installed and operated on combined cycle facilities using catalysts with temperature ranges from 600 to 750°F and generally achieving 9 ppmvd (corrected to 15-percent O_2) or less while burning natural gas.

Ammonium salts (ammonium sulfate and ammonium bisulfate) are formed by the reaction of sulfur oxides in the gas stream and ammonia. These salts are highly acidic and special precautions in materials and ammonia injection rates must be implemented to minimize their formation.

Ammonia injected in the SCR system, which does not react with NO_x, is emitted directly and referred to as ammonia slip. In general, SCR manufacturers guarantee an ammonia slip to be no more than 9 ppmvd corrected to 15-percent oxygen (O_2). SCR is technically feasible for the Project.

Although $SCONO_x$™ is available, it has not been demonstrated on a "F" Class combustion turbine. Performance data on future applications on "F" Class turbines considering $SCONO_x$™ will only likely be available after 2002, well after the facility is scheduled for construction. The $SCONO_x$™ system has only been operated on a 32-MW facility in California since 1996 and a 5 MW unit in Massachusetts since 1999. The scale up of this complicated technology should not be underestimated. The $SCONO_x$™ technology installed on an "F" Class turbine would involve about a dozen or more different chambers of catalyst for absorption and regeneration. Every 15 to

30 minutes, dampers would be operated to isolate a particular catalyst chamber for regeneration. Each regeneration cycle must isolate the chamber so that O_2 is not introduced and regeneration gas (hydrogen) is introduced. Seal leaks could be significant as applied to the large volume flows associated with a "F" Class turbine. Although the amount of sulfur in natural gas is very low, the $SCONO_x$™ catalyst is poisoned with sulfur compounds requiring the installation of the $SCOSO_x$™ to further remove sulfur compounds as part of the overall system. While the distillate oil proposed for the Project will contain 0.05 percent sulfur or less, the amount will be about 20 times higher than that normally contained in natural gas. The ability of $SCOSO_x$™ to further remove sulfur compounds as part of the overall $SCONO_x$™ system has not been demonstrated when firing distillate oil.

Over the last several years, the permitting trend for advanced CTs, even in combined cycle configuration, is the use of DLN combustors with SCR. In Region IV, the predominate emission rate established as BACT has been 3.5 ppmvd corrected to 15-percent O_2 when firing natural gas. Several projects in Florida have established case-by-case BACT of 3.5 and 2.5 ppmvd corrected to 15-percent O_2 when firing natural gas using DLN and SCR.

The proposed CTs will be fired with natural gas and distillate oil. The BACT evaluation was based on DLN combustors in combination with SCR and $SCONO_x$™. The BACT evaluation considered both 3.5 and 2.5 ppmvd corrected to 15 percent oxygen when firing natural gas.

The following sections present a summary of the economic, environmental, and energy impacts of the available, technically feasible and demonstrated control technology alternatives for the combined cycle units. Appendix B contains the detailed information on the costs, environmental, and energy impacts.

Impacts Analysis – 3.5 ppmvd Corrected to 15 Percent O_2

Economic--The total estimated capital costs of SCR on a CT/HRSG are $2,365,937. The total annualized cost of applying SCR with DLN combustion is $1,136,656. Appendix B contains the detailed cost estimates for the capital and annualized costs. The incremental cost effectiveness of adding SCR to the DLN combustors is estimated at $4,216 per ton of NO_x removed.

The capital and annualized costs for $SCONO_x$™ are based on a budgetary cost estimate provided by ABB Alstom Environmental Systems. The budgetary estimate of capital costs for $SCONO_x$™ on one turbine/HRSG unit for one combined cycle unit is \$26.6 million. In contrast, the capital costs for SCR is about \$2.4 million, which clearly is about 10 times less costly than $SCONO_x$™ of SCR. The annualized cost of $SCONO_x$™ is estimated at \$5.3 million. The cost effectiveness of $SCONO_x$™ is \$19,800 per ton of NO_x. In contrast, the cost effectiveness of SCR is about \$4,200 per ton of NO_x removed. The cost effectiveness of $SCONO_x$™ is over 400 percent higher than SCR with uncertainty in its demonstrated feasibility. It should be noted that the annualized costs for $SCONO_x$™ did not include provisions for required mechanical maintenance activities.

Environmental--The maximum predicted NO_x impact of the Project is considerably below the NO_2 PSD Class II increment of 25 $\mu g/m^3$ (annual average) and the AAQS of 100 $\mu g/m^3$ (annual average). The maximum annual impact for the Project is about 0.6 $\mu g/m^3$ when firing natural gas, which is less than 1 percent of the AAQS. The addition of SCR will reduce NO_x emissions by about 270 TPY per CT/HRSG (about 67-percent reduction) from the combined cycle operation beyond those achieved through the use of DLN combustors.

The use of DLN combustor technology is "pollution prevention". The use of SCR has associated primary and secondary environmental impacts. Emissions of ammonia and ammonium salts (such as ammonium sulfate and bisulfate) will occur. Ammonia emissions with the use of SCR are a result of unreacted ammonia that may be emitted. Vendors typically provide ammonia slip guarantees of 9 ppmvd corrected to 15-percent O_2. Maximum ammonia emissions are 112 TPY at the guarantee ammonia slip level. However, this level of ammonia slip occurs only as the catalyst ages. Initial ammonia slip levels are less than 5 ppmvd. Potential emissions of ammonium sulfate and bisulfate will increase emissions of PM_{10} and up to 11.9 TPY could be emitted.

The electrical energy required to run the SCR system and the backpressure from the turbine will reduce the available power from the Project. The backpressure is a result of the catalyst modules located in the exhaust gas stream in the HRSG. With use of DLN combustors at an emission level of 9 ppmvd (corrected to 15-percent O_2), the backpressure to reduce NO_x to 3.5 ppmvd (corrected to 15-percent O_2) is about 2.5 inches of water gauge. This backpressure reduces the power generated by the combustion turbine. This lost power, which would otherwise be available to the electrical system, will have to be replaced by other less efficient units. The replacement power will cause air pollutant emissions that would not have occurred without SCR. The net reduction in emissions with SCR (i.e., reduction in NO_x minus ammonia and secondary emissions), when all criteria pollutants are considered, will be about 140 TPY. In addition to criteria pollutants, additional secondary emissions of carbon dioxide would be emitted.

SCR will require the construction and maintenance of storage vessels for aqueous ammonia for use in the reaction. Ammonia has potential health effects, and the construction of ammonia storage facilities triggers the application of at least three major standards: Clean Air Act (section 112), Occupational Safety and Health Administration (OSHA) 29 CFR 1910.1000, and OSHA 29 CFR 1910.119. The Project proposes using aqueous ammonia for the SCR system.

While ammonia is not used or emitted from a $SCONO_x$™ system, there are substantial natural gas, steam, and back pressure for the $SCONO_x$™ system that would directly result in environmental impacts. $SCONO_x$™ requires about 17,795 lb/hr of steam and 80 lb/hr of natural gas. In addition, the backpressure of the $SCONO_x$™ system is 200 percent over that of the SCR. This increased energy use would create additional criteria pollutants of about 41 TPY per unit and about 23,000 TPY per unit of additional carbon dioxide emissions compared to the Project using SCR (i.e., about 3,400 TPY per unit).

<u>Energy</u>--Energy penalties occur with SCR. With SCR, the output of the CT can be reduced over that of advanced low-NO_x combustors due to the backpressure on the CT. In combined cycle configuration and with a low base emission level (i.e., 9 ppmvd corrected to 15-percent O_2) and 67 percent NO_x reduction, the output reduction is estimated to be about 0.3 percent. This penalty is the result of the SCR pressure drop, which would be about 2.5 inches of water and would amount to about 4,532,000 kWh per year in potential lost generation. The energy required by the SCR equipment would be about 700,800 kWh per year. Taken together, the total lost generation and energy requirements of SCR of 5,233,000 kWh per year could supply the electrical needs of about 426 residential customers. To replace this lost energy, an additional 5.4 x 10^{10} British thermal units per year (Btu/yr) or about 54 million cubic feet per year (ft^3/yr) of natural gas would be required.

$SCONO_x$™, in contrast to SCR, is very energy intensive. The $SCONO_x$™ system has about 2 times more backpressure on the turbine requires steam and natural gas for the regeneration process. The natural gas needed to generate the steam for the $SCONO_x$™ system is equivalent to 26.3 MMBtu/hr/unit or 230,000 MMBtu per year per unit. The overall energy usage is equivalent to about 34,800,000 kW per hours per year or equivalent energy for about 2,900 residential customers.

The energy equivalence in terms of natural gas usage is 362 million cubic feet per year or about 7 times that of SCR. When all the energy requirements for $SCONO_x$™ are considered, it is about 2.32 percent of the combustion turbine heat input. In contrast, SCR results in an additional 0.35 percent of the combustion turbine heat input.

Technology Comparison--The proposed Project will use an advanced heavy-duty industrial gas turbine with advanced DLN combustors. This type of machine advances the state-of-the-art for CTs by being more efficient and less polluting than previous CTs. Integral to the machine's design is DLN combustors that prevent the formation of air pollutants within the combustion process, thereby minimizing the amount of add-on controls that can have an impact on the environment. An analogy of this technology is a more efficient automotive engine that gives better mileage and reduces pollutant formation without the need of a catalytic converter.

An advanced gas turbine is unique from an engineering perspective in two ways. First, the advanced machine is larger and has higher initial firing (i.e., combustion) temperatures than conventional turbines. This results in a larger, more thermally efficient machine. For example, the electrical generating capability of the proposed "F" class advanced machine is about 170 MW compared to the 70 to 120 MW conventional machines. The higher initial firing temperature (i.e., 2,600°F) results in about 20 percent more electrical energy produced for the same amount of fossil fuel used in conventional machines. This has the added advantage of producing less air pollutant emissions (e.g., NO_x, PM, and CO) for each MW generated. While the increased firing temperature increases the thermal NO_x generated, this NO_x increase is controlled through combustor design.

The second unique attribute of the advanced machine is the use of DLN combustors that will reduce NO_x emissions to 9 ppmvd when firing natural gas. Thermal NO_x formation is inhibited by using staged combustion techniques where the natural gas and combustion air is premixed prior to ignition. This level of control will result in NO_x emissions of about 0.04 lb/10^6 Btu for gas firing, which are less than half of the emissions generated from conventional fossil fuel-fired steam generators.

The use of SCR on combined cycle projects has been a recent trend in Florida and Region IV. Its use can limit NO_x emissions, while retaining much of the benefits of the advanced CT technology in combined cycle configuration.

From a technology standpoint, SCR has been demonstrated as feasible on over 100 combined cycle projects. In contrast, $SCONO_x$™ has only been operating over a few years on small turbines that are over ten times smaller than the "F" Class turbine being proposed for the Project. As noted from the information in Appendix B, the $SCONO_x$™ system requires a considerable amount of mechanical equipment that must be operated in a high volume flow field. SCR has no moving parts to complicate operation. Over time, there is considerable uncertainty in the maintenance and replacement requirements of the mechanical components of the $SCONO_x$™ system on a large turbine.

<u>Economic Impact Analysis – 2.5 ppmvd Corrected to 15 Percent O_2</u>-- Appendix B contains cost evaluation for a NO_x emission rate of 2.5 ppmvd corrected to 15-percent O_2 when firing natural gas. The NO_x emission rate when firing distillate oil was kept at 12 ppmvd corrected to 15-percent O_2. The cost for SCR were adjusted based on vendor estimates. For $SCONO_x$™, the capital cost was kept the same and only the catalyst changeout cost were increased.

The results of the evaluation for total cost effectiveness are presented below:

	SCR @ 3.5 ppmvd	$SCONO_x$™ @ 3.5 ppmvd
Total Annualized Costs	$1,136,656	$5,328,516
Cost Effectiveness	$4,216	$19,765
	SCR @ 2.5 ppmvd	$SCONO_x$™ @ 2.5 ppmvd
Total Annualized Costs	$1,479,017	$5,682,303
Cost Effectiveness	$4,918	$18,894

Note: Total tons removed at 3.5 ppmvd is 270 TPY and at 2.5 ppmvd is 301 TPY.

Assuming that $SCONO_x$™ can achieve 2.0 ppmvd corrected to 15-percent O_2 when firing gas the cost effectiveness is about $18,000 per ton of NO_x removed (for about 316 TPY removed). It should be emphasized that $SCONO_x$™ is not considered a demonstrated technology for "F" Class combustion turbines and has not been used or proposed when firing distillate oil. Moreover, the operational experience is non existent on "F" Class turbines. Indeed, the cost effectiveness did not consider any additional operational cost of this technology as a result of the extensive mechanical equipment required. Moreover, $SCONO_x$™ has considerable collateral environmental and energy impacts as noted in the application.

The incremental cost using SCR from an emissions rate of 3.5 ppmvd corrected to 15-percent O_2 to 2.5 ppmvd corrected to 15-percent O_2 is shown below:

Incremental Cost Effectiveness (3.5 to 2.5 ppmvd)	
$1,479,017	Annualized cost for SCR at 2.5 ppmvd
$1,136,656	Annualized cost for SCR at 3.5 ppmvd
$342,360.55	Difference
100.69	TPY emissions at 2.5 ppmvd
131.84	TPY emissions at 3.5 ppmvd
31.15	TPY reduced
$10,989.03	Incremental Cost Effectiveness

Technical Feasibility--There are also significant issues in demonstration compliance with an emission limit as low as 2.5 ppmvd corrected to 15-percent O_2. Such problems will occur with an emission rate of 3.5 ppmvd but be exacerbated with even a lower limit. The difficulties include the reliability of the continuous emission monitoring measurement, availability and stability of calibration gases, precision and accuracy of reference measurements (e.g., EPA Method 7E) and increased ammonia slip. Moreover, there is a general lack of experience in demonstrating compliance over the long term. These concerns are being evaluated by the Electric Power Research Institute (EPRI) Low Level NO_x Project, and the project has validated many of these concerns. While this project is still on going, the information to date suggests the potential trend of increasing ammonia injection rates to maintain low NO_x levels and difficulties in monitor performance. The latter included increased span drift and bias test failures during RATA testing. As a result of these monitoring issues, a longer averaging time is considered appropriate for a 2.5 ppmvd emission limit.

Environmental--There would also be collateral environmental consequences to achieve a NO_x emission rate of 2.5 ppmvd corrected to 15-percent O_2 rather than 3.5 ppmvd corrected to 15-percent O_2. This will be a direct result of increased backpressure on the turbine resulting from more catalyst volume required. Backpressure will increase by 15 percent over the proposed BACT emission rate resulting in increased energy losses and greater secondary emissions. Indeed, the lost energy will increase by 679,759 kW-hours/year/turbine or enough additional electric power to support about 57 residential customers for a year. To supply this lost energy, at least 0.8 TPY of additional criteria pollutants as well as 443 TPY of additional carbon dioxide would be generated.

Proposed BACT and Rationale for Combined Cycle Operation

The proposed BACT for combined cycle operation is advanced DLN combustion technology and SCR. The proposed NO_x emissions level using this technology is 2.5 ppmvd corrected to 15-percent O_2 when firing natural gas and 12 ppmvd corrected to 15-percent O_2 when firing distillate fuel oil. This combination of the technology can achieve the maximum amount of emission reduction available, technically feasible and demonstrated for the Project. SCR cannot be rejected based on the economic, environmental, and energy impacts given the recent BACT decisions on other similar projects.

$SCONO_x$™ is rejected as BACT based on significant energy, environmental and economic impacts. The costs are significantly different between SCR and $SCONO_x$™, yet both technologies can achieve the same level of NO_x reduction. From an environmental perspective, the only advantage of $SCONO_x$™ is the lack of ammonia slip. Ammonia is an unregulated air pollutant and ammonia slip can be minimized through design and operation of the SCR system. $SCONO_x$™ requires steam and natural gas that SCR does not require. These have direct environmental consequences in the form of additional air pollutant emissions including about 23,000 TPY per unit of additional CO_2. Thus, the energy and other environmental disadvantages of $SCONO_x$™ outweigh any advantages in the reduction of these emissions. Taking together the energy, economic and environmental impacts and other costs, $SCONO_x$™ is rejected as BACT. In addition, the use of distillate fuel oil further limits the ability of $SCONO_x$™ to be used for the Project.

4.3.3 NITROGEN OXIDES – SIMPLE CYCLE

Technology Description

The Martin Unit 8A and 8B are proposed to operate in simple cycle mode during the first year of operation (3,390 hours/year) and limited hours when combined cycle operations begins (1,000 hours/year). The emissions rates established as BACT in attainment areas have predominately been based on emissions using DLN combustion technology when firing natural gas and water injection when firing oil. For the GE Frame 7FA turbine these emission rates established as BACT have been 9 ppmvd corrected to 15-percent O_2 when firing natural gas and 42 ppmvd corrected to 15-

percent O_2 when firing distillate oil. These are the current GE guarantees. FDEP has approved numerous projects with these emission limits as BACT including the BACT determination Martin Units 8A and 8B issued in 2000.

In its Guidance for Power Plant Siting and Best Available Control Technology document, the California Air Resources Board (CARB 1999) states that the most stringent BACT limit for NO_x from a simple cycle combustion turbine is 5 ppmv (3-hour average) based on the Carson Energy Group facility in California. This project is a small (<50 MW) aeroderivative turbine. In a discussion of exhaust gas temperature considerations, CARB also states that whereas catalytic control systems are feasible for aeroderived simple cycle gas turbines, "the high exhaust temperatures approaching 1,100°F" of industrial frame gas turbines (such as the GE industrial frame series) "may require case-by-case evaluation regarding the feasibility of NO_x control through selective catalytic reduction."

Manufacturers of SCR were contacted regarding application of "hot" SCR on large frame combustion turbines. This includes the "E" class and "F" Class turbines. The "E" Class turbines have slightly lower exhaust temperatures (up to 1,100°F) than the "F" Class turbines (up to 1,200°F). However, the exhaust temperatures for both type of turbines exceed 1,000°F and some type of cooling is required. Applications of SCR to simple cycle projects have been applied to one known "E" Class turbine and four known "F" Class turbines (two operating and two planned for operation). Engelhard Corporation remains the only supplier providing application of "hot" SCR above 1,000°F. Engelhard's experience with "hot" SCR lists 112 turbines that are either operating or planned to operate. Of these 112 turbines, only 5 turbines are "E" or "F" Class in size. Through discussion with Kenneth Burns of Engelhard Corporation, as the only manufacturer of the high-temperature zeolite catalyst for hot SCR systems, there are currently no projects involving a dual-fuel "F" Class combustion turbine and hot SCR. In all "hot" SCR applications on and "F" Class turbines, the turbines have only been firing with natural gas and the exhaust gases are cooled to 1,025°F or less.

The application of "hot" SCR is not considered technically feasible for the Project. This is based on the lack of demonstration of this technology on dual fuel gas turbines and anticipated technical difficulties associated with oil firing. In the 1990s, there are four simple cycle combustion turbine projects that have installed SCR with any significant operating experience.

These projects are:

- Redding Municipal Power – 3 GE Frame 5 CTs fired with natural gas. The CTs are operated as a peaking facility.
- SoCal Gas Company – 4 Solar Centaur CTs (4MW equivalent each) fired with natural gas. The CTs are operated in intermediate cycling duty.
- UnoCal Brea Research Center – a single 4 MW CT firing natural gas. The CT operates in intermediate to base load duty.
- Puerto Rico Electric Power Authority (Cambalache Facility) – 3 ABB Type 11 N (83 MW each) firing No. 2 distillate oil.

The SCRs for all these CTs were designed to operate at temperatures less than 1,000°F. Many of the smaller CTs have exhaust temperatures less than 1,000°F. The Cambalache Facility had a once through steam generator in the ductwork leading to SCR used for power augmentation that reduced the catalyst temperature to less than 1,000°F. Experience on these systems has shown significant catalyst deactivation occurs with peaking and intermediate cycling duty while firing natural gas. Under these conditions catalyst deactivation has occurred after operating from 350 to 4,000 hours. For intermediate-base load duty and firing natural gas, catalyst deactivation improved but still occurred after 8,000 hours of operation and well less than the catalyst guarantee. When firing distillate oil, catalyst deactivation occurred after 600 hours. The SCR system for the Cambalache Facility had significant problems resulting in the removal of the SCR catalyst. The units proposed for Martin Unit 8 will be peaking units that will be limited to 1,500 hours per year. The normal operation of these units will be fast startups with maximum operation of 16 hours/day or less. Startup is relatively a short time period (i.e., about 30 minutes) with temperatures exceeding 1,000°F. This type of operation will result in wide variations of exhaust temperatures causing significant thermal stresses on downstream equipment. The need to use oil is also a limiting factor in the application of SCR for the Project because of the demonstrated technical difficulties experienced with oil firing in "hot SCR" systems. Inherent in the consideration of technical feasibility, is the ability of the alternative control technology to meet an emission limit.

"Hot" SCR has even been determined not to be feasible in ozone non-attainment areas where LAER is the applicable criteria rather than BACT. For example, in the summer of 2000, the Maryland Department of Environment (MDE) evaluated the installation of "hot" SCR on GE Frame 7FA turbines for the Old Dominion Electric Cooperative Rock Springs Project. The MDE concluded that

- Redding Municipal Power – 3 GE Frame 5 CTs fired with natural gas. The CTs are operated as a peaking facility.
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In addition, the installation of "hot" SCR has considerable co-lateral economic, environmental and energy disadvantages that are components of the BACT analysis. Many of these disadvantages have been identified for modern combustion turbines in guidance issued by John Seitz, Director of EPA's Office of Air Quality Planning and Standards (EPA, 2000a).

Impact Analyses

Economic Impacts

The total capital and annualized cost for SCR applied to simple cycle operation for one GE Frame 7FA was developed (Golder, 2000). The costs were developed using EPA Cost Control Manual (EPA, 1990 & 1993). Vendor based estimates were used for the SCR system, while assuming the technology could consistently achieve 3.5 ppmvd corrected to 15-percent O_2 when firing natural gas and 15 ppmvd corrected to 15-percent O_2 when firing distillate oil. It should be noted that these emission limits have not been demonstrated in practice. In performing the economic analysis, standard EPA recommended cost factors were used. A capital recovery period of 15 years at 7 percent was used for determining the annualized costs of capital. The total capital costs of "hot" SCR for the simple cycle operation are estimated to be $5,866,600. This is a factor of two higher than SCR installed in the HRSG. The total annualized cost of applying SCR with DLN combustion and water injection is $1,728,750 for 3,390 hours of operation and $1,659,000 for 1,000 hours of operation. The incremental cost effectiveness of adding SCR to the DLN combustors and water injection (for oil firing) is estimated at about $25,200 and $57,700 per ton of NO_x removed for 3,390 hours and 1,000 hours, respectively. This cost effectiveness for "hot" SCR is substantially higher than applying SCR in the HRSG and higher than that previously considered appropriate for BACT for NO_x.

Energy Impacts

Significant energy penalties occur with "hot" SCR. With SCR, the output of the CT can be reduced by up to 0.50 percent over that of advanced low-NO_x combustors. This is the estimated reduction in CT output resulting from "hot" SCR. This penalty is the result of the SCR pressure drop, which would be about 4 inches of water and would amount to about 3,870,000 kWh per year in potential lost generation for 3,390 hours per year. This lost energy could supply the electrical needs of about 320 residential customers. To replace this lost energy, an additional 37.5 x 10^{10} British thermal units per year (Btu/yr) or about 37 million ft^3/yr of natural gas would be required.

Environmental Impacts

The maximum predicted NO_x impacts using the DLN technology with the simple cycle unit is considerably below the NO_2 PSD Class II increment of 25 $\mu g/m^3$ (annual average) and the AAQS of 100 $\mu g/m^3$ (annual average). The maximum annual impact for the Project in simple cycle operation is less than 1 $\mu g/m^3$ (PSD significant impact level), which is less than one percent of the AAQS and less than the significant impact level of 1 $\mu g/m^3$. The effect of adding "hot" SCR on the simple cycle operation will have marginal overall air quality benefits given the proposed period of long-term operation (1,000 hours/year when combined cycle begins). Indeed, these have been recognized by EPA in evaluating DLN technology for combined cycle technology (EPA, 2000b). This includes the collateral impact resulting from ammonia emissions, formation of fine particulates, global warming and ammonia safety.

The use of DLN combustor technology is truly "pollution prevention" for simple cycle operation. The use of "Hot" SCR has associated primary and secondary environmental impacts. The electrical energy required to run the SCR system and the back pressure from the turbine will reduce the available power. The back pressure is a result of the amount of catalyst needed for the reduction and the velocity of exhaust gases. With simple cycle applications, the back pressure from "hot" SCR is about 4 inches of water gauge, significantly reducing the available power. This power, which would otherwise be available to the electrical system, will have to be replaced by other units. The replacement power will cause air pollutant emissions that would not have occurred without SCR. In addition, since the simple cycle unit provides peaking power, the replacement energy will be from much older and less efficient units, with much higher emission rates. In addition to criteria pollutants, additional secondary emissions of carbon dioxide would be emitted.

Proposed NO_x BACT

The proposed BACT for simple cycle operation is based on emission rates using advanced DLN combustion technology when firing natural gas and water injection when firing distillate oil. The proposed NO_x emissions level using this DLN technology is 9 ppmvd corrected to 15-percent O_2 when firing natural gas. The NO_x emissions rate when oil firing will be controlled using water injection to 42 ppmvd corrected to 15-percent O_2. This combination of the technology can achieve the maximum amount of emission reduction available, is technically feasible and demonstrated for the limited amount of simple cycle operation proposed for the Project. SCR is rejected based on the technical feasibility, and economic, environmental, and energy impacts. Moreover, the simple cycle operation will be limited after combined cycle in operational. In combined cycle configuration, SCR has been determined to be technical feasible and cost effective. The proposed BACT is consistent with recent BACT decisions on other similar projects.

"Hot" SCR is rejected for the following reasons:

- SCR has not been demonstrated on an "F" Class dual fuel turbine. Applications of this technology on much smaller turbines have not been successful. SCR is considered technically infeasible for the Project.
- The estimated incremental cost of "Hot" SCR is approximately 10 times higher on a $ per ton of NO_x removed basis, than SCR applied to combined cycle. Similar costs for other projects that have rejected "Hot" SCR as being unreasonable. This is even more apparent if additional pollutant emissions due to SCR are considered.
- The energy impacts of SCR will reduce potential electrical power generation much greater than that for combined cycle (about 70% greater). This amount of energy is sufficient to provide greater electrical power for residential customers. Moreover, simple cycle operation will only be used when power demands are high (first year) or when combined cycle becomes inoperative. Peaking energy supplied by more efficient and lower polluting units will benefit the environment.
- The proposed BACT (i.e., DLN combustion) provides the most cost effective control alternative for simple cycle operation, is pollution preventing, and results in low environmental impacts (less than the significant impact levels). DLN combustion at the proposed emissions levels has been adopted in BACT determinations for simple cycle projects.

4.3.4 CARBON MONOXIDE

Technology Description

Emissions of CO are dependent on the combustor design, which is a result of the manufacturer's operating specifications, including the air-to-fuel ratio, staging of combustion, and the amount of water injected. The CTs proposed for the Project have designs to optimize combustion efficiency and minimize NO_x emissions to the lowest achievable using DLN combustion technology while maintaining low CO emission levels.

For the Project, the following alternatives were evaluated as BACT:

1. Combustion controls, and
2. Oxidation catalyst at 2 ppmvd emission rate.

There are two alternatives for installing an oxidation catalyst. The first would be to install a catalyst prior to the HRSG to reduce CO emissions from the turbine. This would result in the CO emissions from the duct burners being uncontrolled. The second alternative is to install an oxidation catalyst or $SCONO_x$™ within the HRSG. This would control all the CO emissions, including CO from the duct burners. The capital cost for an oxidation catalyst and its technical feasibility is not different when considering simple or combined cycle operation

Impact Analysis

Economic--The estimated capital cost for an oxidation catalyst installed in the HRSG is $1.64 million. The annualized cost of a CO oxidation catalyst is $691,000. The resulting cost effectiveness is approximately $4,165 per ton of CO removed for gas and oil firing. No costs are associated with combustion techniques, since they are inherent in the design.

$SCONO_x$™ also reduces CO emissions. The incremental cost effectiveness for CO removal for this system is over $20,000 per ton. This is based on the differential between the annualized cost of $SCONO_x$™ ($5.3 million) and SCR ($1.1 million) and the tons of CO potentially removed in the $SCONO_x$™ system.

Environmental--The air quality impacts of both oxidation catalyst control and combustion design control techniques are below the significant impact levels for CO. Therefore, no significant environmental benefit would be realized by the installation of a CO catalyst. Moreover, the air quality impacts, at the proposed CT emission rate, are predicted to be much less than the PSD significant impact levels. The maximum CO impacts are less than 0.1 percent of the applicable AAQS. There would also be no secondary benefits, such as reductions in O_3 precursors and acidic deposition, to reducing CO.

In contrast, the installation of an oxidation catalyst would create additional back pressure on the turbine that will result in lost electric generation that would otherwise be available and thus replaced by older, less efficient technology. The end result is an additional 1,970 TPY of carbon dioxide (CO_2). The ultimate end product of CO is CO_2, regardless of whether the process results from an oxidation catalyst or in the atmosphere. The lost energy caused by the back pressure from the oxidation catalyst would result in the generation of 10 times more greenhouse gases than the amount of CO converted to CO_2 in the oxidation catalyst.

__Energy__--An energy penalty would result from the pressure drop across the catalyst bed. A pressure drop of about 1.5 to 2 inches of water gauge would be expected. A catalyst back pressure of 2 inches would result in an energy penalty of about 3 million kWh/yr. The energy penalties are sufficient to supply the electrical needs of about 252 residential customers for a year. To replace this lost energy, about 3.1×10^{10} Btu/yr or about 31 million ft^3/yr of natural gas would be required. In contrast, the total energy requirements of $SCONO_x$™ is 36.3×10^{10} Btu/yr or about 363 million ft^3/yr of natural gas.

__Proposed BACT and Rationale__

Combustion design is proposed as BACT, as there are adverse technical and economic consequences of using catalytic oxidation on CTs. The proposed BACT emission rates for CO will not exceed 9 ppmvd when firing natural gas at baseload to 50-percent load (simple and combined cycle), 22.9 ppmvd when firing natural gas with duct firing (combined cycle) and 20 ppmvd when firing distillate oil (simple and combined cycle). Catalytic oxidation is considered unreasonable for the following reasons:

1. Catalytic oxidation will not produce measurable reduction in the air quality impacts,
2. The economic impacts are significant (i.e., the capital cost is $1.64 million, with an annualized cost of about $691,000 per year per unit), and
3. Recent projects in Florida and Region IV have been authorized with BACT emission limits of similar magnitude.

$SCONO_x$™ is rejected as BACT based on the high differential costs of the technology. Also, the as described in the BACT evaluation for NO_x, the use of $SCONO_x$™ on a "F" Class turbine has associated technical uncertainty, as well as significant energy and environmental impacts.

Combustion design is proposed as BACT as a result of the technical and economic consequences of using catalytic oxidation on CTs. Catalytic oxidation is considered unreasonable, since it will not produce a measurable reduction in the air quality impacts. Indeed, recent BACT decisions for similar advanced CTs have set limits in the 9- to 25-ppmvd range when firing natural gas and distillate oil. The cost of an oxidation catalyst would be significant and not be cost effective given the maximum proposed emission limits.

The cost effectiveness calculations are significantly understated if the actual emission performance is considered. The actual CO emissions performance of the GE Frame 7FA turbines is much less than the guaranteed rates. This is a direct result of turbine manufacturers and duct burner vendors including significant margins on emissions of CO and VOCs to assure that NO_x emission guarantees can be achieved in the combustion systems. CO test data indicated that emissions range from 0.0 to 1.01 ppmvd (corrected to 15-percent O_2) with and average of 0.25 ppmvd (corrected to 15-percent O_2) when firing natural gas over loads from 50 percent to 100 percent. These data were from 67 tests. The GE guarantee is equivalent to 7.4 ppmvd corrected to 15-percent O_2 (i.e., 9 ppmvd) when firing natural gas. The actual CO emissions over 10 times less than the guarantee emission level.

4.3.5 PM/PM_{10}, SO_2, AND SULFURIC ACID MIST

The PM/PM_{10} emissions from the CTs are a result of incomplete combustion and trace elements in the fuel. The design of the CT ensures that particulate emissions will be minimized by combustion controls and the use of clean fuels. A review of EPA's BACT/LAER Clearinghouse Documents did not reveal any post-combustion particulate control technologies being used on gas-fired or distillate oil-fired CTs.

The maximum particulate emissions from the CT will be lower in concentration than that normally specified for fabric filter designs. The grain loading associated with the maximum particulate emissions (less than 20 lb/hr when firing natural gas) is less than 0.01 grain per standard cubic foot (gr/scf), which is a typical design specification for a baghouse. This further demonstrates that no further particulate controls are necessary for the proposed Project.

There are no technically feasible methods for controlling the emissions of SO_2 and sulfuric acid mist from CTs, other than the inherent quality of the fuel. The use of flue gas desulfurization (FGD) systems are not available, technically feasible, demonstrated or cost effective on CTs using natural gas. The use of natural gas, a clean fuel, represents BACT and will limit emissions of SO_2.

4.3.6 VOLATILE ORGANIC COMPOUNDS

VOCs will be emitted by the CTs as a result of incomplete combustion. The proposed emission rates for VOC emissions will be the use of combustion technology and the use of clean fuels so that emissions when firing natural gas will not exceed 1.5 ppmvd when firing natural gas at baseload and 7.0 ppmvd when duct firing. When firing distillate oil the emissions will not exceed 3.5 ppmvd. This emission level is similar to the BACT emission levels established for other similar sources. Combustion controls and the use of clean fuels have been overwhelmingly approved as BACT for CTs. The environmental effect of further reducing emissions would not be significant.

A review of the BACT/LAER Information System (BLIS) did not indicate any oxidation catalysts on natural gas fired combustion turbines to limit emissions of VOCs. A vendor of oxidation catalysts was contacted to determine the removal of VOCs in an oxidation catalyst typically used (i.e., primarily used for CO in nonattainment areas as LAER). The vendor stated that the typical VOC removal in a turbine application is from 30 to 40 percent. The cost effectiveness calculation is presented below:

VOC Cost Effectiveness Calculations

2.74	lb/hr gas firing at baseload
11.54	lb/hr gas firing at baseload w/duct firing
7.28	lb/hr oil firing
25.81	TPY
40.00%	removal
10.32	TPY removal
$66,936	per ton VOC removed
90.00%	removal
23.22738	TPY removed
$29,749	per ton VOC removed

At 40-percent VOC removal the cost effectiveness of an oxidation catalyst is over $66,000 per ton of VOC removed. Assuming that 90 percent reduction were available at the same cost, the cost effectiveness is over $29,000 per ton of VOC removed.

Similar to the results for CO, the actual VOC emission rates have been extremely low when compared with the emission guarantees. VOC test data indicated that emissions range from 0.0 to 1.65 ppmvd (corrected to 15-percent O_2) with and average of 0.23 ppmvd (corrected to 15-percent O_2) when firing natural gas over loads from 50 to 100 percent. These data were from 34 tests. The GE guarantee is 1.3 ppmvd (corrected to 15-percent O_2). The actual VOC emissions are 5 times lower than the guarantee emission level. Test results for duct firing with natural gas suggest that VOC emission rates remain unchanged.

4.3.7 GAS HEATERS

The emissions from these units are a result of incomplete combustion and trace elements in the fuel. There are no technically feasible methods for controlling emissions other than the inherent quality of the fuel (i.e., natural gas, diesel fuel oil). BACT proposed for the gas heaters is based on limiting annual hours of operation as indicated in the application.

4.3.8 COOLING TOWER

For the cooling tower, the installation of drift eliminators is the only feasible technology for controlling PM emissions. Drift eliminators use inertial separation caused by airflow direction changes to remove water droplets from the air stream exhausting from the cooling tower. These water droplets generally contain the same concentration of dissolved solids and chemical impurities as the water circulating through the tower and can be converted to airborne emissions.

Drift eliminator configurations include cellular (or honeycomb), wave-form, and herringbone (blade-type) designs. Drift eliminators may include various materials such as wood installed or formed into closely spaced slats, sheets, honeycomb assemblies, or tiles; ceramics, fiberglass, metal, and plastic.

Particulate emissions from the Project's cooling tower will be controlled utilizing high-efficiency drift eliminators achieving a drift loss rate of 0.002 percent of the cooling tower recirculating water flow.

Table 4-1. Proposed BACT Emission Limitations and Compliance Methods For Each CT/HRSG Unit

Pollutant	Emission Rate (Basis[a])	Conditions[b]	Compliance Method Proposed
Particulate Matter	9 / 17.2 lb/hr	SC/CC Gas Firing	VE < 10%
Sulfur Dioxide	17 / 37.8 lb/hr	SC/CC Oil Firing	VE < 20%
	10.2 / 13.3 lb/hr	SC/CC Gas Firing	Pipeline Natural Gas
	103.1 lb/hr	SC/CC Oil Firing	Distillate Oil (0.05-percent maximum sulfur)
Nitrogen Oxides	9 / 2.5 ppmvd corrected to 15-percent O_2	SC/CC Gas Firing	EPA Method 7E Initial Test; CEM 24-hour Block Average
	42 / 12 ppmvd corrected to 15-percent O_2	SC/CC Oil Firing	EPA Method 7E Initial Test; CEM 24-hour Block Average
Carbon Monoxide	9 ppmvd	SC/CC Gas Firing no DB	EPA Method 10
	24.5 ppmvd	CC Gas Firing with DB	EPA Method 10
	29.5 ppmvd	CC Gas Firing HPM/DB	EPA Method 10
	20 ppmvd	SC/CC Oil Firing	EPA Method 10
Volatile Organic Compounds	1.5 ppmvw	SC/CC Gas Firing no DB	EPA Methods 18, 25, or 25a
	7 ppmvw	CC Gas Firing with DB	EPA Methods 18, 25, or 25a
	3.5 ppmvw	SC/CC Oil Firing	EPA Methods 18, 25, or 25a

[a] Based on maximum emission rate over turbine inlet operating conditions.
[b] Operating loads from 50 to 100 percent.

Note:
CC = combined cycle.
DB = duct burner.
HPM = higher power mode.
ppmvd = parts per million, volume dry.
ppmvw = parts per million, volume wet.
SC = simple cycle.

5.0 AMBIENT MONITORING ANALYSIS

The CAA requires that an air quality analysis be conducted for each criteria and noncriteria pollutant subject to regulation under the act before a major stationary source is constructed. Criteria pollutants are those pollutants for which AAQS have been established. Noncriteria pollutants are those pollutants that may be regulated by emission standards, but no AAQS have been established. This analysis may be performed by the use of modeling and/or by monitoring the air quality. In addition, if EPA has not established an acceptable ambient monitoring method for the pollutant, monitoring is not required.

Based on the estimated emissions from the Project (see Table 3-3), pre-construction ambient monitoring analyses for SO_2, PM_{10}, NO_2, CO, ozone (based on VOC emissions) and sulfuric acid mist are required to be submitted as part of the application. The ambient monitoring analysis is not required if it can be demonstrated that the proposed source's maximum air quality impacts will not exceed the PSD *de minimis* concentration levels and, for ozone (based on VOC emissions), VOC emission level of 100 TPY.

As shown in Table 3-4, the proposed Project's impacts are predicted to be below the *de minimis* monitoring concentrations when the Project is operating in simple cycle configuration. When the Project is operating in combined cycle configuration, the Project's impacts are also predicted to be below the applicable *de minimis* monitoring concentrations. In the case of ozone, the Project's VOC emissions are greater than the monitoring emission level of 100 TPY. Therefore, pre-construction ambient monitoring analyses for ozone (based on VOC emissions) are required to be submitted as part of the application.

For sulfuric acid mist, which is a noncriteria pollutant, although the Project's emissions are greater than the significant emission rate, EPA has established no acceptable monitoring method for this pollutant.

As a result, ambient ozone monitoring data from existing monitoring stations operated by FDEP are included in this application to satisfy the pre-construction monitoring requirement. Martin County and adjacent counties are classified as attainment for ozone. There are no ozone monitors located in Martin County. The nearest monitor to the Project that measures ozone concentrations is located at Fort Pierce in St. Lucie County (AIRS No. 12-111-0012), located approximately 50 km to the northeast of the Project. Since ozone is a regional pollutant, ozone monitoring data collected in St. Lucie County are considered to be representative of ozone concentrations for the region and is used to satisfy this requirement for the Project. This station is operated by the FDEP and measure concentrations according to EPA procedures.

From 1998 through July 2001, the second-highest 1-hour average ozone concentration measured at this site was 0.095 ppm. This maximum concentration is less than the existing 1-hour average ozone AAQS of 0.12 ppm. In addition, the 3-year average of the 4th highest 8-hour average ozone concentration was 0.073 ppm that is below the proposed 8-hour average ozone AAQS of 0.08 ppm. These O_3 monitoring data are proposed as part of this construction permit application to satisfy the preconstruction monitoring requirement for the project.

Therefore, based on the existing ozone ambient data and lack of an acceptable monitoring method for sulfuric acid mist, an exemption from the preconstruction monitoring requirement for ozone and sulfuric acid mist in accordance with the PSD regulations is appropriate.

6.0 AIR QUALITY IMPACT ANALYSIS

6.1 SIGNIFICANT IMPACT ANALYSIS APPROACH

6.1.1 SITE VICINITY

The general modeling approach followed EPA and FDEP modeling guidelines for determining compliance with AAQS and PSD increments. For all criteria pollutants that will be emitted in excess of the PSD significant emission rate due to a proposed project, a significant impact analysis is performed to determine whether the emission and/or stack configuration changes due to the project alone will result in predicted impacts that are in excess of the EPA significant impact levels at any location beyond the plant's restricted boundaries.

If the project-only impacts are above the significant impact levels in the vicinity of the facility, then two additional and more detailed air modeling analyses are required. The first analysis demonstrates compliance with federal and Florida ambient air quality standards (AAQS), and the second analysis demonstrates compliance with allowable PSD Class II increments.

6.1.2 PSD CLASS I AREAS

Generally, if the facility undergoing the modification is within 200 kilometers of a PSD Class I area, then a significant impact analysis is also performed to evaluate the impact due to the project alone at the PSD Class I area. The PSD Class I area of Everglades NP is located approximately 144 km from the Project. Because Everglades NP is located within 200 km of the Project, the maximum predicted impacts at the Everglades NP are compared to EPA's proposed significant impact levels for PSD Class I areas. These recommended levels have never been promulgated as rules but are the currently accepted criteria to determine whether a proposed project will incur a significant impact on a PSD Class I area.

If the project-only impacts at the PSD Class I area are above the proposed EPA PSD Class I significant impact levels, then an analysis is performed to demonstrate compliance with allowable PSD Class I impacts at the PSD Class I area.

In addition, the project's maximum concentrations are evaluated at the PSD Class I area for pollutants whose emissions are greater than the significant emission rate, to address potential impacts on air quality related values (AQRV). This analysis includes an evaluation of regional haze degradation.

6.2 PRE-CONSTRUCTION MONITORING ANALYSIS APPROACH

The modeling approach followed EPA and FDEP modeling guidelines for evaluating a project's impacts relative to the *de minimis* monitoring levels to determine the need to submit ambient monitoring data prior to construction. Current FDEP policies stipulate that the predicted highest annual average and highest short-term concentrations are to be compared to the applicable *de minimis* monitoring levels.

6.3 AIR MODELING ANALYSIS APPROACH

6.3.1 GENERAL PROCEDURES

As stated in the previous sections, for each pollutant which is emitted above the significant emission rate, air modeling analyses are required to determine if the Project's impacts are predicted to be greater than the significant impact levels and *de minimis* monitoring levels. These analyses consider the Project's impacts alone. Air quality impacts are predicted using 5 years of meteorological data and selecting the highest predicted ground-level concentrations for comparison to the significant impact levels and *de minimis* monitoring levels.

To predict the maximum annual and short-term concentrations for the proposed Project, the modeling approach was divided into screening and refined phases. Concentrations are predicted for the screening phase using a coarse receptor grid and a 5-year meteorological data record. If the highest concentration is predicted at a receptor that lies in an area where the receptor spacing is more than 100 m, then a refined analysis is performed in that area using a receptor grid of greater resolution. Modeling refinements are performed using a receptor spacing of 100 m or less with a receptor grid centered on the screening receptor at which the maximum concentration was predicted. The air dispersion model is then executed with the refined grid for the entire year of meteorology during which the screening concentration occurred.

If the Project's impacts are greater than the significant impact levels, the air modeling analyses must consider other nearby sources and background concentrations to predict a total concentration for comparison to AAQS. Because the proposed Project's maximum 24-hour SO_2 impacts are predicted to be greater than the significant impact level, additional AAQS and PSD Class II Increment analyses were performed for this pollutant and averaging time.

Generally, when using 5-years of meteorological data for the analysis, the highest annual and the highest, second-highest (HSH) short-term concentrations are compared to the applicable AAQS and allowable PSD increments. [Note that for determining compliance with the 24-hour AAQS for PM_{10}, the sixth highest predicted concentration in five years (i.e., H6H), instead of the HSH, is used to compare to the applicable 24-hour AAQS.]

The HSH concentration is calculated for a receptor field by:

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

The HSH approach is consistent with air quality standards and allowable PSD increments, which permit a short-term average concentration to be exceeded once per year at each receptor.

The AAQS analysis is a cumulative source analysis that evaluates whether the concentrations from all sources will comply with the AAQS. These concentrations include the modeled impacts from sources at the project site and from other nearby facility sources added to a background concentration. The background concentration accounts for sources not included in the modeling analysis.

The PSD Class II analysis is a cumulative source analysis that evaluates whether the concentrations for increment-affecting sources will comply with the allowable PSD Class II increments. These concentrations include the modeled impacts from PSD increment-affecting sources at the project site, plus nearby PSD increment-affecting sources at other facilities.

6.3.2 PSD CLASS I ANALYSIS

For each pollutant for which a significant impact is predicted at the PSD Class I area, a PSD Class I analysis is required. The PSD Class I analysis is a cumulative source analysis that evaluates whether the concentrations for increment-affecting sources located within 200 km of the PSD Class I area will comply with the allowable PSD Class I increments. These concentrations include the impacts from PSD increment-affecting sources at the project site, plus the impacts from PSD increment-affecting sources at other facilities.

6.4 MODEL SELECTION

The selection of an air quality model to calculate air quality impacts for the Project was based on its applicability to simulate impacts in areas surrounding the Project as well as at the PSD Class I area of interest. Two air quality dispersion models were selected and used in these analyses to address air quality impacts for the Project. These models were:

- The Industrial Source Complex Short Term (ISCST3) dispersion model, and
- The California Puff model (CALPUFF)

The ISCST3 (Version 00100) dispersion model (EPA, 2000) was used to evaluate the pollutant impacts due to the Project in nearby areas surrounding the Site. This model is maintained by the EPA on its internet website, Support Center for Regulatory Air Models (SCRAM), within the Technical Transfer Network (TTN). A listing of ISCST3 model features is presented in Table 6-1. The ISCST3 model is designed to calculate hourly concentrations based on hourly meteorological data (i.e., wind direction, wind speed, atmospheric stability, ambient temperature, and mixing heights). The ISCST3 model is applicable to sources located in either flat or rolling terrain where terrain heights do not exceed stack heights. These areas are referred to as simple terrain. The model can also be applied in areas where the terrain exceeds the stack heights. These areas are referred to as complex terrain.

In this analysis, the EPA regulatory default options were used to predict all maximum impacts. The ISCST3 model can be executed in the rural or urban land use mode that affects stability dispersion coefficients, wind speed profiles, and mixing heights. Land use can be characterized based on a scheme recommended by EPA (Auer, 1978). If more than 50 percent land use within a 3-km radius around a project is classified as industrial or commercial, or high-density residential, then the urban option should be selected. Otherwise, the rural option is appropriate. Based on the land-use within a 3-km radius of the Project, the rural dispersion coefficients were used in the modeling analysis. Also, since the terrain around the facility is flat to gently rolling, the simple terrain feature of the model was selected. The ISCST3 model was used to provide maximum concentrations for the annual and 24-, 8-, 3-, and 1-hour averaging times.

At distances beyond 50 km from a source, the CALPUFF model, Version 5.4 (EPA, 2000), is recommended for use by the EPA and the Federal Land Manager (FLM). The CALPUFF model is a long-range transport model applicable for estimating the air quality impacts in areas that are more than 50 km from a source. The CALPUFF model is maintained by the EPA on the SCRAM internet website. The methods and assumptions used in the CALPUFF model are based on the latest recommendations for modeling analysis as presented in the following reports:

- The Interagency Workgroup on Air Quality Models (IWAQM), *Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts* (EPA, 1998); and
- The *Federal Land Manager's Air Quality Relative Values Workgroup (FLAG) Phase I Report* (December, 2000).

In addition, updates to the modeling methods and assumptions were followed based on discussion with the FLM.

The CALPUFF model was used to perform a significant impact analysis for the Project at the PSD Class I area of Everglades NP and to assess the Project's impact on regional haze and total nitrogen and sulfur deposition levels. A more detailed description of the assumptions and methods used for the CALPUFF model is presented in Table 6-2 and in Appendix C.

6.5 METEOROLOGICAL DATA

Meteorological data used in the ISCST3 model to determine air quality impacts consisted of a concurrent 5-year period of hourly surface weather observations and twice-daily upper air soundings from the National Weather Service (NWS) office located at the Palm Beach International Airport (PBI). The 5-year period of meteorological data was from 1987 through 1991. The NWS office at PBI is located approximately 45-km southeast of the site and is the closest primary weather station to the study area considered to have meteorological data representative of the project site. The PBI station meteorological data have been approved by the FDEP and used for numerous air modeling studies submitted as part of air construction permits approved for sources located in Palm Beach County.

CALMET, the meteorological preprocessor to CALPUFF, was used to develop a 3-dimensional wind field necessary to perform the air modeling analysis to evaluate pollutant impacts at each PSD Class I area. The modeling domain consisted of a rectangular 3-dimensional grid that extended from approximately 79.0 to 83.5 degrees longitude and from 23.75 to 28.0 degrees latitude. The modeling domain includes the following meteorological and land use parameters:

- Surface weather data,

- Upper air data,
- A 1-degree land use data,
- A 1-degree Digital Elevation Model (DEM) terrain data,
- Mesoscale Model - Generation 4 (MM4) data (for initializing the wind field), and
- Hourly precipitation data.

These data were obtained and processed for the calendar year 1990, the year for which MM4 data are available on CD. The CALMET wind field and the CALPUFF model options used were consistent with the suggestions of the FLMs. Meteorological data used with the CALPUFF model consist of a CALMET-developed wind field covering south Florida. More detailed descriptions of the assumptions and methods used for processing the meteorological data and establishing the model domain are presented in Appendix C.

6.6 EMISSION INVENTORY

6.6.1 SIGNIFICANT IMPACT ANALYSIS

A summary of the criteria pollutant emission rates, physical stack and stack operating parameters for the proposed CTs, operating in combined- and simple-cycle configurations, that were used in the air modeling analysis are presented in Tables 2-1 through 2-4. The emission and stack operating parameters presented are for 3 operating loads and 35°F, 59°F and 95°F ambient temperatures for the CTs firing natural gas and oil. Additional operating cases were also considered that included power augmentation and high power mode for the CTs firing natural gas. In an effort to obtain the maximum air quality impacts for a range of possible operating conditions, the air modeling used a range of emission rates and stack parameter data to predict air quality impacts.

A total of 21 modeling scenarios were considered for simple-cycle configuration with the CTs operating for the following conditions:

- CTs firing natural gas for ambient temperatures of 35, 59, and 95°F at:
  - 100 percent operating load
  - 75 percent operating load
  - 50 percent operation load
  - High Power Mode
- CTs firing oil for ambient temperatures of 35, 59, and 95°F at:
  - 100 percent operating load

- 75 percent operating load
- 50 percent operation load

A total of 21 modeling scenarios were considered for combined-cycle configuration with the CTs operating for the following conditions:

- CTs firing natural gas for ambient temperatures of 35, 59, and 95°F at:
  - 100 percent operating load with duct firing
  - 75 percent operating load
  - 50 percent operation load
  - power augmentation load with duct firing
- CTs firing oil for ambient temperatures of 35, 59, and 95°F at:
  - 100 percent operating load
  - 75 percent operating load
  - 50 percent operation load

The proposed CTs will have a HRSG stack height of 120 ft and an inner stack diameter of 19 ft and a bypass stack height of 80 feet with and inner stack diameter of 22 ft. Because the proposed stack heights are less than GEP, building downwash effects were included in the modeling analysis (see following section on building downwash). The relative locations of the stacks used in the modeling analysis were:

	Relative Location (m)	
Stacks	X	Y
HRSG Stack No. A	-152.7	55
HRSG Stack No. B	-107.1	55
HRSG Stack No. C	0	55
HRSG Stack No. D	45.7	55
Bypass Stack No. A	-152.7	0
Bypass Stack No. B	-107.1	0
Bypass Stack No. C	0	0
Bypass Stack No. D	45.7	0

The air modeling origin was assumed to be located at Bypass Stack C, which is located a UTM east and north coordinates of 543100 and 2992900 m, respectively, in UTM Zone 18.

The ISCST3 model was used to predict maximum concentrations for the annual and 24-, 8-, 3-, and 1-hour averaging times. To estimate impacts due to emissions from the stacks, an emission rate of 79.365 pounds per hour (lb/hr) or 10 grams per second (g/s) was initially used to produce relative concentrations as a function of the modeled emission rate (i.e., $\mu g/m^3$ per 10 g/s). These impacts are referred to as generic pollutant impacts. Maximum air quality impacts for specific pollutants were then determined by multiplying the maximum pollutant-specific emission rate in lb/hr (g/s) by the maximum predicted generic impact divided by 79.365 lb/hr (10 g/s).

For the PSD Class I area of the Everglades NP, concentrations were predicted for the Project for combined- and simple-cycle operation with the CALPUFF model based on the operating scenario with the maximum hourly emissions. For both natural gas- and oil-firing, maximum emissions are based on the CTs operating for baseload conditions at an ambient temperature of 35°F.

For the CTs operating in combined cycle mode and firing natural gas, the duct burner emissions are included. For simple cycle operation and natural gas-firing, the CTs are assumed to operate at higher power mode.

Annual average concentrations are based on the operating scenarios with the maximum hourly emissions for the following annual hours:

- For SO_2 and PM_{10}: combined cycle operation with natural gas- and fuel oil-firing for 8,260 and 500 hours, respectively;
- For NO_2: combined cycle operation with natural gas-firing for 7,760; simple cycle operation with natural gas- and fuel oil-firing for 500 hours each; and
- For CO: combined cycle operation with natural gas-firing for 8,760.

6.6.2 AAQS AND PSD CLASS II ANALYSES

As discussed in Section 6.10, the maximum impacts from the Project were predicted to be less than the significant impact levels for all pollutants, except SO_2 for the 24-hour averaging period. As a result a cumulative source analysis is required to demonstrate compliance with the 24-hour average SO_2 AAQS and PSD Class II increments.

A listing of background SO_2 sources used in the AAQS and PSD Class II modeling analyses and their locations relative to the Project is provided in Table 6-3. All facilities were evaluated using the North Carolina screening technique. Based on this technique, facilities whose annual (i.e., ton per year) emissions are less than the threshold quantity, Q, are eliminated from the modeling analysis. Q is equal to 20 x (D-SIA), where D is the distance in km from the facility to the Project and SIA is the distance of the proposed project's SO_2 significant impact area (9 km). The SO_2 facilities that were not eliminated in the screening analysis are available for inclusion in the AAQS and PSD Class II analyses.

Detailed SO_2 background source data that were used for the AAQS and PSD Class II analyses are presented in Appendix D. Non-Project SO_2 PSD sources were obtained from FDEP and were supplemented with current and historical information available within Golder.

6.6.3 PSD CLASS I ANALYSIS

Similar to the maximum Project impacts predicted in the Project's vicinity, the maximum Project impacts at the PSD Class I area of the Everglades NP are predicted to by less than the proposed Class I significant impact levels for all pollutants, except SO_2 for the 24-hour averaging period. As a result, a cumulative source impact analysis is required to demonstrate compliance with the 24-hour average SO_2 PSD Class I increment.

A listing of background SO_2 sources that were used in the PSD Class I analysis and their locations relative to the PSD Class I area of the Everglades NP is provided in Table 6-4. PSD sources located within 200 km of the Everglades NP were included in the PSD Class I modeling analysis. Detailed SO_2 background source data that were used for the PSD Class I analysis are presented in Appendix D.

6.7 RECEPTOR LOCATIONS

6.7.1 SITE VICINITY

To determine the maximum impact for all pollutants and averaging times in the Project's vicinity, concentrations were predicted at receptors located in a detailed polar receptor grid centered on the modeling origin. This grid was comprised of 180 radials, spaced at 2-degree intervals along each radial. Receptors were located at the following distances from the origin:

- Every 100 m out to 3 km;

- Every 250 m from 3 km to 7 km;
- Every 500 m from 7 km to 10 km; and
- Every 5,000 m from 10 km to 30 km.

Additionally, Cartesian receptors were placed every 50 m along the plant boundary. The Lakes Environmental ISC-Aermod View software program, Version 4.0, was utilized to produce the receptor grid and boundary receptors. Receptors located within the plant boundary (fence-line) were removed from the modeling receptor grid, since this area is restricted and not considered to be ambient air locations. In order to remove the plant receptors, the polar receptor grids were first converted to Cartesian coordinates, due to the procedures in the software program, see Appendix E for a graphical representation of the resulting receptor grid as well as an example input file for a detailed list of receptor points.

To determine the 24-hour average SO_2 significant impact area for the Project, a second receptor grid was developed using a polar receptor grid centered on the modeling origin. This grid was comprised of 180 radials, with receptors spaced at 2-degree intervals along each radial. Receptors were located every 1000 meters out to a distance of 15 km from the modeling origin. Additionally, 657 Cartesian receptors, spaced at 50 m, were used to predict impacts along the plant boundary. The receptor locations, along with the plant property boundary and the modeling origin, are shown in Appendix E.

6.7.2 CLASS I AREA

Maximum pollutant concentrations were predicted with the CALPUFF model using 126 discrete receptors located along the border of the PSD Class I area of the Everglades NP. These receptors were also used in the AQRV analysis to address the Project's impacts on regional haze and sulfur and nitrogen deposition. A listing of Class I receptors used in the modeling analysis is provided in Table 6-5.

6.8 BACKGROUND CONCENTRATIONS

To estimate total air quality 24-hour average SO_2 concentrations in the site vicinity, a background concentration must be added to the AAQS modeling results. The background concentration is considered to be the air quality concentration contributed by sources not included in the modeling evaluation.

For this analysis, the highest 24-hour average SO_2 concentration of 34 $\mu g/m^3$ measured for the past four years in Palm Beach County was used to represent background concentration. This concentration was obtained from a monitoring station operated by the FDEP in Riviera Beach (AIRS number 12-099-3004). This background level was added to model-predicted concentrations to estimate total air quality levels for comparison to AAQS.

6.9 BUILDING DOWNWASH EFFECTS

All significant building structures in the Project area were identified by the site plot plan (see Figure 2-2). The building structures were processed in the EPA Building Input Profile (BPIP, Version 95086) program to determine direction-specific building heights and widths for each 10-degree azimuth direction for each source that was included in the modeling analysis. A listing of dimensions for each structure is presented in Table 6-6. See Appendix E for plots of these building structures.

6.10 MODEL RESULTS

6.10.1 PSD CLASS II SIGNIFICANT IMPACT ANALYSIS

The maximum pollutant concentrations predicted for the Project by operating load and air inlet temperature for simple-cycle operation are given in Table 6-7. The maximum pollutant concentrations predicted for the Project by operating load and air inlet temperature for combined-cycle operation are given in Table 6-8. A summary of the predicted maximum SO_2, NO_x, CO, and PM_{10} concentrations predicted for the Project for the significant impact analysis is presented in Table 6-9. The modeling results indicated that maximum concentrations due to the Project are predicted to be less than the significant impact levels for all pollutants except SO_2 for the 24-hour averaging period. The significant impact area for the project's SO_2 concentrations extends out approximately 9 km for the Project. As a result, additional modeling analyses were performed for SO_2 to address compliance with AAQS and PSD increments.

6.10.2 AAQS ANALYSIS

A summary of the maximum HSH 24-hour average SO_2 concentrations predicted for all sources for the screening analysis is presented in Table 6-10. Based on the screening analysis results, modeling refinements were performed.

The maximum predicted HSH 24-hour SO_2 concentration is 109 $\mu g/m^3$. This concentration includes a non-modeled 24-hour background concentration of 34 $\mu g/m^3$. The maximum predicted HSH 24-hour average SO_2 concentration is below the Florida AAQS 260$\mu g/m^3$.

6.10.3 PSD CLASS II ANALYSIS

Summaries of the maximum SO_2 PSD increment consumption predicted for all sources for the screening analysis is presented in Table 6-11. Based on the screening analysis results, modeling refinements were performed.

The maximum predicted HSH 24-hour SO_2 increment consumption concentration of 41.4 $\mu g/m^3$, is less than the allowable PSD Class II increments of 91 $\mu g/m^3$.

6.10.4 PSD CLASS I INCREMENT ANALYSIS

The modeling analysis results for the Project at the Everglades NP are summarized in Table 6-12. When firing natural gas, the primary fuel, the maximum SO_2, PM_{10} and NO_2 pollutant concentrations are predicted to be well below the EPA proposed PSD Class I significant impact levels. When firing fuel oil, the maximum 24-hour average SO_2 concentrations were also predicted to be the EPA proposed PSD Class I significant impact levels for all pollutants, except SO_2 for the 24-hour average period. Therefore, a more detailed analysis for determining compliance with the 24-hour SO_2 PSD Class I increment was performed.

The results of the PSD Class I increment analysis are presented in Table 6-13. The highest, second-highest predicted 24-hour SO_2 concentration is 3.5 $\mu g/m^3$, which is below the allowable 24-hour PSD Class I increment of 5 $\mu g/m^3$.

6.10.5 CONCLUSIONS

Based on these air quality modeling analyses, the maximum pollutant concentrations due to the Project's emissions are predicted to be less than the PSD Class II and I significant impact levels for all pollutants except SO_2 for the 24-hour averaging period. As a result, more detailed SO_2 modeling analyses including offsite sources were performed for PSD Class II and I areas. The results of the modeling analysis demonstrate the Project will not have a significant affect on air quality and will comply with all applicable AAQS and PSD increments.

Table 6-1. Major Features of the ISCST3 Model

ISCST3 Model Features
• Polar or Cartesian coordinate systems for receptor locations
• Rural or one of three urban options which affect wind speed profile exponent, dispersion rates, and mixing height calculations
• Plume rise due to momentum and buoyancy as a function of downwind distance for stack emissions (Briggs, 1969, 1971, 1972, and 1975; Bowers, et al., 1979).
• Procedures suggested by Huber and Snyder (1976); Huber (1977); and Schulman and Scire (1980) for evaluating building wake effects
• Procedures suggested by Briggs (1974) for evaluating stack-tip downwash
• Separation of multiple emission sources
• Consideration of the effects of gravitational settling and dry deposition on ambient particulate concentrations
• Capability of simulating point, line, volume, area, and open pit sources
• Capability to calculate dry and wet deposition, including both gaseous and particulate precipitation scavenging for wet deposition
• Variation of wind speed with height (wind speed-profile exponent law)
• Concentration estimates for 1 hour to annual average times
• Terrain-adjustment procedures for elevated terrain including a terrain truncation algorithm for ISCST3; a built-in algorithm for predicting concentrations in complex terrain
• Consideration of time-dependent exponential decay of pollutants
• The method of Pasquill (1976) to account for buoyancy-induced dispersion
• A regulatory default option to set various model options and parameters to EPA recommended values (see text for regulatory options used)
• Procedure for calm-wind processing including setting wind speeds less than 1 m/s to 1 m/s.

Note: ISCST3 = Industrial Source Complex Short-Term

References:

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Pasquill, F. 1976. Atmospheric Dispersion Parameters in Gaussian Plume Modeling - Part II. Possible Requirements for Change in the Turner Workbook Values. EPA-600/4-76-030b, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711.

Schulman, L.L. and J.S. Scire. 1980. Buoyant Line and Point Source (BLP) Dispersion Model User's Guide. Document P-7304B, Environmental Research and Technology, Inc., Concord, MA.

Table 6-2. Major Features of the CALPUFF Model, Version 5.4

CALPUFF Model Features
• Source types: Point, line (including buoyancy effects), volume, area (buoyant, non-buoyant)
• Non-steady-state emissions and meteorological conditions (time-dependent source and emission data; gridded 3-dimensional wind and temperature fields; spatially-variable fields of mixing heights, friction velocity, precipitation, Monin-Obukhov length; vertically and horizontally-varying turbulence and dispersion rates; time-dependent source and emission data for point, area, and volume sources; temporal or wind-dependent scaling factors for emission rates)
• Efficient sampling function (integrated puff formulation; elongated puff (slug) formation)
• Dispersion coefficient options (Pasquill-Gifford (PG) values for rural areas; McElroy-Pooler values (MP) for urban areas; CTDM values for neutral/stable; direct measurements or estimated values)
• Vertical wind shear (puff splitting; differential advection and dispersion)
• Plume rise (buoyant and momentum rise; stack-tip effects; building downwash effects; partial plume penetration above mixing layer)
• Building downwash effects (Huber-Snyder method; Schulman-Scire method)
• Complex terrain effects (steering effects in CALMET wind field; puff height adjustments using ISC model method or plume path coefficient; enhanced vertical dispersion used in CTDMPLUS)
• Subgrid scale complex terrain (CTSG option) (CTDM flow module; dividing streamline as in CTDMPLUS)
• Dry deposition (gases and particles; options for diurnal cycle per pollutant, space and time variations with a resistance model, or none)
• Overwater and coastal interaction effects (overwater boundary layer parameters; abrupt change in meteorological conditions, plume dispersion at coastal boundary; fumigation; option to use Thermal Internal Boundary Layers (TIBL) into coastal grid cells)
• Chemical transformation options (Pseudo-first-order chemical mechanisms for SO_2, SO_4, HNO_3, and NO_3; Pseudo-first-order chemical mechanisms for SO_2, SO_4, NO, NO_2, HNO_3, and NO_3 (RIVAD/ARM3 method); user-specified diurnal cycles of transformation rates; no chemical conversions)
• Wet removal (scavenging coefficient approach; removal rate as a function of precipitation intensity and type)
• Graphical user interface
• Interface utilities (scan ISCST3 and AUSPLUME meteorological data files for problems; translate ISCST3 and AUSPLUME input files to CALPUFF input files

Note: CALPUFF = California Puff Model
Source: EPA, 2000.

Table 6-3. Summary of SO_2 Facilities Considered for Inclusion in the AAQS and PSD Class II Air Modeling Analyses

			UTM Coordinates		Relative to FPL Martin Plant [a]				Maximum SO_2	Q, Emission	Include in
AIRS Number	Facility	County	East (km)	North (km)	X (km)	Y (km)	Distance (km)	Direction (deg)	Emissions (TPY)	Threshold [b] (Dist - SIA) x 20	Modeling Analysis ?
0850102	Bechtel Indiantown	Martin	545.6	2991.5	2.5	-1.4	2.9	119	2,629	SIA	YES
0990021	Pratt & Whitney	Palm Beach	559.2	2978.3	16.1	-14.6	21.7	132	504	254.7	YES
0990019	Osceola Farms	Palm Beach	544.2	2968.0	1.1	-24.9	24.9	177	2,023	318.5	YES
0990061	U.S. Sugar -Bryant	Palm Beach	538.8	2968.1	-4.3	-24.8	25.2	190	2,698	323.4	YES
0850021	Stuart Contracting	Martin	575.2	3006.8	32.1	13.9	35.0	67	100	519.6	NO
0990026	Sugar Cane Growers	Palm Beach	534.9	2953.3	-8.2	-39.6	40.4	192	2,555	628.8	YES
0990086	Glades Correctional Institute	Palm Beach	523.4	2955.2	-19.7	-37.7	42.5	208	98	670.7	NO
0990016	Atlantic Sugar	Palm Beach	552.9	2945.2	9.8	-47.7	48.7	168	954	793.9	YES
	Fort Pierce Utilities	St. Lucie	566.8	3036.3	23.7	43.4	49.4	29	2,708	809.0	YES
0510001	Everglades Sugar	Hendry	509.6	2954.2	-33.5	-38.7	51.2	221	1,216	843.7	YES
0510003	U.S. Sugar Clewiston	Hendry	506.1	2956.9	-37.0	-36.0	51.6	226	7,806	852.5	YES
0990234	Palm Beach Resource Recovery	Palm Beach	585.8	2960.2	42.7	-32.7	53.8	127	1,533	895.7	YES
	Okeelanta	Palm Beach	525.0	2937.4	-18.1	-55.5	58.4	198	939	987.5	NO
0990042	FPL -Riviera Beach[c]	Palm Beach	594.2	2960.6	51.1	-32.3	60.5	122	73,475	1029.0	YES
0510015	Southern Gardens Citrus	Hendry	487.6	2957.6	-55.5	-35.3	65.8	238	409	1135.5	NO
	Vero Beach Power [c]	St. Lucie	567.1	3056.5	24.0	63.6	68.0	21	11,832	1179.6	YES
0990568	Lake Worth Utilities[c]	Palm Beach	592.8	2943.7	49.7	-49.2	69.9	135	8,996	1218.7	YES
0110120	North Broward Resource Recovery	Broward	583.6	2907.6	40.5	-85.3	94.4	155	896	1708.5	NO

Note: deg = degrees
km = kilometers
SIA = significant impact area
TPY = tons per year

[a] FPL Martin Plant's East and North Coordinates (km) are: 543.1 and 2992.9 , respectively.

[b] Based on North Carolina Screening Technique for annual average basis. "Dist" is the distance the facility is located from the project. "SIA" is the significant impact area. The project's 24-hour SO_2 concentrations are predicted to be significant out to 9 km from the project.

[c] Large source with annual emissions greater than 1,000 TPY located beyond the screening area (59 km) that were included in the inventory.

Table 6-4. Summary of SO_2 Facilities Included in the PSD Class I Air Modeling Analysis

			UTM Coordinates		Relative to Everglades National Park			
AIRS Number	Facility	County	East (km)	North (km)	x (km)	y (km)	Distance [a] (km)	Direction (deg)
0250348	Dade Co. Resource Recovery	Dade	564.3	2857.4	14.3	8.8	16.8	58
0250020	Tarmac	Dade	562.9	2861.7	12.9	13.1	18.4	45
0112119	South Broward Resource Recovery	Broward	579.6	2883.3	29.6	34.7	45.6	40
0110037	FPL -Lauderdale	Broward	580.1	2883.3	30.1	34.7	45.9	41
0110120	North Broward Resource Recovery	Broward	583.6	2907.6	33.6	59.0	67.9	30
0710019	Lee County Resource Recovery	Lee	424.0	2946.0	-30.0	82.8	88.1 [b]	340
0990332	Okeelanta	Palm Beach	525.0	2937.4	-25.0	88.8	92.3	344
0710000	FPL - Fort Myers	Lee	422.1	2952.9	-31.9	89.7	95.2 [b]	340
0990016	Atlantic Sugar	Palm Beach	552.9	2945.2	2.9	96.6	96.6	2
0990568	Lake Worth Utilities	Palm Beach	592.8	2943.7	42.8	95.1	104.3	24
0990026	Sugar Cane Growers Coop.	Palm Beach	534.9	2953.3	-15.1	104.7	105.8	352
0510003	U.S. Sugar Clewiston	Hendry	506.1	2956.9	-43.9	108.3	116.9	338
0990234	Palm Beach Resource Recovery	Palm Beach	585.8	2960.2	35.8	111.6	117.2	18
0990019	Osceola Farms	Palm Beach	544.2	2968.0	-5.8	119.4	119.5	357
0990061	U.S. Sugar -Bryant	Palm Beach	538.8	2968.1	-11.2	119.5	120.0	355
0510015	Southern Gardens Citrus	Hendry	487.6	2957.6	-62.4	109.0	125.6	330
0990021	Pratt & Whitney	Palm Beach	559.2	2978.3	9.2	129.7	130.0	4
0850102	Bechtel Indiantown	Martin	545.6	2991.5	-4.4	142.9	143.0	358
0850001	FPL -Martin	Martin	543.1	2992.9	-6.9	144.3	144.5	357

[a] Distance from the northeastern corner of the Everglades National Park, UTM East and North coordinates (km) of 550.0 and 2848.6 , respectively, unless noted.
[b] Distance from the northwestern corner of the Everglades National Park, UTM East and North coordinates (km) of 454.0 and 2863.2 , respectively.

Table 6-5. Receptors of the PSD Class I Area of the Everglades NP

UTM Coordinates (m)		UTM Coordinates (m)		UTM Coordinates (m)		UTM Coordinates (m)	
East	North	East	North	East	North	East	North
557000	2789000	538000	2848600	514500	2837000	470000	2860000
556600	2792000	537000	2848600	514500	2836000	469000	2860000
556000	2796000	536000	2848600	514500	2835000	468000	2860000
553000	2796500	535000	2848600	514500	2834000	467000	2860000
548000	2796500	534000	2848600	514500	2833000	466000	2860000
542700	2796500	533000	2848600	514500	2832500	465000	2860000
542700	2800000	532000	2848600	510000	2832500	464000	2860000
542700	2805000	531000	2848600	509000	2832500	463000	2860000
542700	2810000	530000	2848600	508000	2832500	462000	2860000
542000	2811000	529000	2848600	507000	2832500	461000	2860000
541300	2814000	528000	2848600	506000	2832500	460000	2860000
542700	2816000	527000	2848600	505000	2832500	459500	2863200
544100	2820000	526000	2848600	504000	2832500	459000	2863200
543500	2824600	525000	2848600	503000	2832500	458000	2863200
545000	2829000	524000	2848600	502000	2832500	457000	2863200
545700	2832200	523000	2848600	501000	2832500	456000	2863200
546200	2835700	522000	2848600	500000	2832500	455000	2863200
548600	2837500	521000	2848600	499000	2832500	454000	2863200
550300	2839000	520000	2848600	498000	2832500		
545000	2839000	519000	2848600	497000	2832500		
540000	2839000	518000	2848600	496000	2832500		
550500	2844000	517000	2848600	495000	2832500		
545000	2844000	516000	2848600	495000	2833000		
540000	2844000	515000	2848600	495000	2834000		
550300	2848600	514500	2848600	495000	2835000		
549000	2848600	514500	2848000	495000	2836000		
548000	2848600	514500	2847600	494500	2837000		
547000	2848600	514500	2846600	491500	2841000		
546000	2848600	514500	2845000	488500	2845500		
545000	2848600	514500	2844000	483000	2848500		
544000	2848600	514500	2843000	480000	2852500		
543000	2848600	514500	2842000	475000	2854000		
542000	2848600	514500	2841000	473500	2857000		
541000	2848600	514500	2840000	473000	2860000		
540000	2848600	514500	2839000	472000	2860000		
539000	2848600	514500	2838000	471000	2860000		

Note: FPL Martin Plant's UTM East and North coordinates are 543100 m, 2940100 m, repectively.
m = meter.

Table 6-6. Project Building Dimensions Used in the Modeling Analysis

Stucture	Height		Length		Width	
	ft	m	ft	m	ft	m
CT Air Inlet A	45	13.72	48.3	14.72	24	7.3
CT Inlet Sructure A	66.5	20.27	10.5	3.2	44.6	13.6
HRSG Structure A	83	25.3	74.5	22.7	31	9.45
CT Air Inlet B	45	13.72	48.3	14.72	24	7.3
CT Inlet Sructure B	66.5	20.27	10.5	3.2	44.6	13.6
HRSG Structure B	83	25.3	74.5	22.7	31	9.45
CT Air Inlet C	45	13.72	48.3	14.72	24	7.3
CT Inlet Sructure C	66.5	20.27	10.5	3.2	44.6	13.6
HRSG Structure C	83	25.3	74.5	22.7	31	9.45
CT Air Inlet D	45	13.72	48.3	14.72	24	7.3
CT Inlet Sructure D	66.5	20.27	10.5	3.2	44.6	13.6
HRSG Structure D	83	25.3	74.5	22.7	31	9.45

Note: CT= combustion turbine; HRSG= heat recovery steam generator

Table 6-7. Maximum Pollutant Concentrations Predicted for the Project by Operating Load and Air Inlet Temperature for Simple Cycle Operation

Pollutant	Averaging Time	Maximum Predicted Concentrations (ug/m^3) by Operating Load and Air Inlet Temperature [a]										
		Power Augmentation	Higher Power Mode	Baseload			75% Load			50% Load		
		80°F	95°F	95°F	59°F	35°F	95°F	59°F	35°F	95°F	59°F	35°F
Natural Gas Operation												
SO_2	Annual	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
	24-Hour	0.09	0.09	0.09	0.09	0.10	0.09	0.09	0.10	0.08	0.09	0.09
	3-Hour	0.41	0.41	0.40	0.42	0.43	0.37	0.40	0.41	0.34	0.36	0.37
PM_{10}	Annual	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
	24-Hour	0.09	0.09	0.09	0.09	0.09	0.11	0.11	0.11	0.13	0.13	0.13
NO_2	Annual	0.06	0.07	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
CO	8-Hour	1.08	1.07	0.63	0.66	0.68	0.64	0.67	0.68	0.61	0.65	0.66
	1-Hour	3.22	3.19	1.84	1.96	1.88	2.59	2.79	2.89	2.23	2.38	2.45
Fuel Oil Operation												
SO_2	Annual	NA	NA	0.07	0.07	0.07	0.07	0.07	0.07	0.06	0.06	0.07
	24-Hour	NA	NA	0.78	0.82	0.84	0.77	0.79	0.81	0.77	0.80	0.82
	3-Hour	NA	NA	3.91	4.13	4.23	3.62	3.92	4.05	3.25	3.46	3.55
PM_{10}	Annual	NA	NA	0.01	0.01	0.01	0.02	0.01	0.01	0.02	0.02	0.02
	24-Hour	NA	NA	0.15	0.14	0.14	0.18	0.17	0.17	0.23	0.22	0.21
NO_2	Annual	NA	NA	0.22	0.22	0.23	0.21	0.22	0.23	0.20	0.20	0.21
CO	8-Hour	NA	NA	1.31	1.38	1.42	1.25	1.30	1.34	1.23	1.27	1.29
	1-Hour	NA	NA	4.08	4.24	4.36	4.27	4.19	4.28	4.00	4.11	4.18

Note: NA = not applicable

[a] Concentrations are based on highest concentrations predicted using five years of meteorological data from 1987 to 1991 of surface and upper air data from the National Weather Service station at Palm Beach International Airport.

Table 6-8. Maximum Pollutant Concentrations Predicted for the Project by Operating Load and Air Inlet Temperature for Combined Cycle Operation

		Maximum Predicted Concentrations (ug/m³) by Operating Load and Air Inlet Temperature [a]									
	Averaging	Power Augmentation	Baseload			75% Load			50% Load		
Pollutant	Time	80°F	95°F	59°F	35°F	95°F	59°F	35°F	95°F	59°F	35°F
Natural Gas Operation [b]											
SO_2	Annual	0.11	0.13	0.13	0.12	0.10	0.11	0.11	0.11	0.12	0.12
	24-Hour	1.60	1.76	1.78	1.76	1.29	1.33	1.37	1.31	1.38	1.42
	3-Hour	3.44	3.74	3.85	3.86	2.77	2.87	2.95	2.86	3.00	3.10
PM_{10}	Annual	0.15	0.19	0.17	0.16	0.15	0.14	0.14	0.20	0.19	0.19
	24-Hour	2.17	2.50	2.37	2.28	1.85	1.77	1.77	2.28	2.23	2.23
NO_2	Annual	0.27	0.34	0.33	0.32	0.24	0.25	0.25	0.26	0.27	0.28
CO	8-Hour	16.23	15.3	14.5	13.9	5.99	6.14	6.31	6.37	6.60	6.79
	1-Hour	38.88	31.4	32.3	31.7	12.3	13.3	13.8	17.9	19.1	19.6
Fuel Oil Operation											
SO_2	Annual	NA	0.40	0.39	0.38	0.48	0.50	0.51	0.55	0.60	0.62
	24-Hour	NA	6.67	6.62	6.46	7.41	7.72	7.83	7.72	8.38	8.64
	3-Hour	NA	14.4	14.6	14.6	15.8	16.7	17.0	15.6	16.9	17.5
PM_{10}	Annual	NA	0.16	0.14	0.14	0.21	0.21	0.21	0.27	0.28	0.29
	24-Hour	NA	2.62	2.48	2.37	3.24	3.23	3.20	3.83	3.97	4.01
NO_2	Annual	NA	0.37	0.36	0.35	0.44	0.46	0.46	0.50	0.54	0.56
CO	8-Hour	NA	6.81	6.72	6.61	7.27	7.58	7.71	7.87	8.30	8.49
	1-Hour	NA	17.5	19.0	19.9	16.3	17.4	18.0	18.0	19.0	19.5

Note: NA = not applicable

[a] Concentrations are based on highest concentrations predicted using five years of meteorological data from 1987 to 1991 of surface and upper air data from the National Weather Service station at Palm Beach International Airport.

[b] Duct firing included for baseload operating load. Duct firing based on natural gas-fired duct burner with maximum heat input rate of 550 mmBtu/hr (HHV).

Table 6-9. Summary of Maximum Pollutant Concentrations Predicted for the Project, Compared to the EPA Class II Significant Impact Levels

Pollutant	Averaging Time	Maximum Predicted Concentration (ug/m^3) Simple Cycle Natural Gas	Simple Cycle Fuel Oil	Combined Cycle Natural Gas	Combined Cycle Fuel Oil	EPA Class II Significant Impact Levels (ug/m^3)
CTs Only						
SO_2	Annual	0.01	0.07	0.13	0.62	1
	24-Hour	0.10	0.84	1.78	8.64	5
	3-Hour	0.43	4.23	3.86	17.5	25
PM_{10}	Annual	0.01	0.02	0.20	0.29	1
	24-Hour	0.13	0.23	2.50	4.01	5
NO_2	Annual	0.07	0.23	0.34	0.56	1
CO	8-Hour	1.08	1.42	16.2	8.49	500
	1-Hour	3.22	4.36	38.9	19.9	2,000
CTs and Cooling Tower						
PM_{10}	Annual	NM	NM	NM	0.34	1
	24-Hour	NM	NM	NM	4.37	5

Note: NM = not modeled.

Table 6-10. Maximum Predicted SO_2 Impacts For Comparison to AAQS- Screening and Refined Analyses

Rank and Averaging Time	Concentration (μg/m³) [a] Total	Modeled Sources	Background	Receptor Location [b] x (m)	y (m)	Time Period (YYMMDDHH)	AAQS (μg/m³)
Screening Analysis							
HSH 24-Hour	107	73	34	-4,145	2,796	87123124	260
	106	72	34	-3,786	2,344	88013024	
	97	63	34	-4,283	2,344	89060424	
	103	69	34	-4,233	2,344	90030824	
	108	74	34	-3,716	3,346	91040424	
Refined Analysis							
HSH 24-Hour	109	75	34	-3,800	3,300	91072424	260
	108	74	34	-4,000	2,800	87061924	

Note: YYMMDDHH = Year, Month, Day, Hour Ending
HSH = Highest, Second-Highest

[a] Concentrations are based on highest concentrations predicted using five years of meteorological data from 1987 to 1991 of surface and upper air data from the National Weather Service station at Palm Beach International Airport.

[b] Relative to Bypass Stack C.

Table 6-11. Maximum Predicted SO_2 Impacts For Comparison to the PSD Class II Increment- Screening and Refined Analyses

Rank and Averaging Time	Concentration (µg/m³) [a] Modeled Sources	Receptor Location [b] x (m)	y (m)	Time Period (YYMMDDHH)	PSD Class II Increment (µg/m³)
Screening Analysis					
HSH 24-Hour	41.4	-2,741	2,344	87123124	91
	36.2	-3,830	3,214	88013024	
	37.4	-1,996	2,344	89060424	
	38.8	-4,061	-1,729	90030824	
	38.0	-4,233	2,344	91040424	
Refined Analysis					
HSH 24-Hour	41.4	-2,741	2,344	87080724	91
	39.1	-4,600	-2,000	90030824	

Note: YYMMDDHH = Year, Month, Day, Hour Ending
HSH = Highest, Second-Highest

[a] Concentrations are based on highest concentrations predicted using five years of meteorological data from 1987 to 1991 of surface and upper air data from the National Weather Service station at Palm Beach International Airport.

[b] Relative to Bypass Stack C.

Table 6-12. Summary of Maximum Pollutant Concentrations Predicted for the Project at the PSD Class I Area of the Everglades NP Compared to the Proposed EPA Class I Significant Impact Levels

Pollutant	Averaging Time	Maximum Concentration ($\mu g/m^3$) [a]			Proposed EPA Class I Significant Impact Levels ($\mu g/m^3$)
		Natural Gas	Fuel Oil	Natural Gas/ Fuel Oil	
Combined-Cycle [b]					
SO_2	Annual [c]	NM	NM	0.0013	0.1
	24-Hour	0.052	0.388	0.388	0.2
	3-Hour	0.110	0.803	0.803	1.0
NO_2	Annual [c]	NM	NM	0.0017	0.1
PM_{10}	Annual [c]	NM	NM	0.0018	0.2
	24-Hour	0.086	0.174	0.174	0.3
Simple-Cycle [b]					
SO_2	Annual [c]	NM	NM	0.0013	0.1
	24-Hour	0.035	0.338	0.338	0.2
	3-Hour	0.074	0.716	0.716	1.0
NO_2	Annual [c]	NM	NM	0.0017	0.1
PM_{10}	Annual [c]	NM	NM	0.0018	0.2
	24-Hour	0.039	0.069	0.069	0.3

Note: NM = not modeled

[a] Concentrations are highest predicted using CALPUFF model and 1990 CALMET wind field for south Florida.

[b] Concentrations predicted for combined- and simple cycle operation are based on the operating scenario with the maximum hourly emissions. For both natural gas- and oil-firing, maximum emissions are based on the combustion turbines operating for baseload conditions at an ambient temperature of 35°F.

For combined cycle operation and natural gas-firing, duct burner emission are included. For simple cycle operation and natural gas-firing, combustion turbines are assumed to operate at higher power mode.

[c] Annual average concentrations are based on the operating scenarios with the maximum hourly emissions for the following annual hours:

1. For SO_2 and PM_{10}: combined cycle operation with natural gas- and fuel oil-firing for 8,260 and 500 hours, respectively; and
2. For NO_2: combined cycle operation with natural gas-firing for 7,760; simple cycle operation with natural gas- and fuel oil-firing for 500 hours each.

Table 6-13. Summary of the Maximum 24-hour Average SO_2 Concentration Predicted for PSD Sources at the PSD Class I Area of the Everglades NP Compared to the Allowable PSD Class I Increment

Averaging Time	Maximum Concentration [a] ($\mu g/m^3$)	Receptor Location (m) UTM East	Receptor Location (m) UTM North	Period Ending (Julian day/ year)	Allowable PSD Class I Increments ($\mu g/m^3$)
24-Hour	3.50	534,000	2,840,600	317/1990	5

Note: UTM = Universal Transverse Mercator

[a] Second-highest concentration predicted with the CALPUFF model.

7.0 ADDITIONAL IMPACT ANALYSIS

7.1 IMPACTS DUE TO ASSOCIATED DIRECT GROWTH

The Project is being constructed to meet current and projected electric demands. FPL has an obligation to meet this increase in electric demand. Additional growth as a direct result of the additional electric power provided by the Project is not expected.

Construction of the Project will occur over a 24-month period requiring an average of approximately 250 workers during that time. It is anticipated that many of these construction personnel will commute to the Site.

The Project will employ a total of 12 operational workers at Project build-out. The operational workforce will also include annual contracted maintenance workers to be hired for periodic routine services. The workforce needed to operate the proposed Project represents a small fraction of the population already present in the immediate area. Therefore, while there would be a small increase in vehicular traffic in the area, the effect on air quality levels would be minimal.

There are also expected to be no air quality impacts due to associated industrial/ commercial growth given the location at the existing Martin Plant. The existing commercial and industrial infrastructure should be adequate to provide any support services that the Project might require and would not increase with the operation of the Project. Since construction of Martin Units 3 and 4 in early 1990, the Indiantown area grew only about 10 percent over the last 10 years. The addition of the nominal 1,000-MW facility had little effect on the increase or growth in the area.

7.2 IMPACTS ON SOILS, VEGETATION, WILDLIFE AND VISIBILITY

The maximum air quality impacts for the Project predicted in the vicinity of the site were used to assess the Project's potential impacts on nearby soils, vegetation, wildlife and visibility.

According to the USDA Martin County Soil Survey, soils in the vicinity of the project are classified as Candler fine sand, an excessively drained, sloping soil found in the sandhill areas of Martin County. Excessively drained, sandy soils are by nature acidic, therefore agricultural uses require amendment of soil with lime to increase alkalinity.

Vegetative communities in the vicinity of the project site are primarily pine plantation, improved pasture, xeric oak hammock, and maintained lawns associated with the wastewater treatment plant and access road right-of-ways.

The Project's impacts on the local air quality are predicted to be less than the significant impact levels for PSD Class II areas, except for the 24-hour average SO_2 concentrations when the Project is operating in combined cycle mode and firing fuel oil. When modeled with background SO_2 emission sources, the total air quality impacts when the Project is operating in combined cycle mode and firing fuel oil are predicted to be less than 58 percent of the AAQS; the Project's impacts are less than 3 percent of the AAQS. Since the AAQS are designed to protect the public welfare, including effects on soils and vegetation, and the Project's impacts are predicted to be generally less than the significant impact levels, no detrimental effects on soils or vegetation should occur in this area due to the Project's operation.

Although air pollution impacts to wildlife have been reported in the literature, many of the incidents involved acute exposures to pollutants, usually caused by unusual or highly concentrated releases or unique weather conditions. Generally, there are three ways pollutants may affect wildlife: through inhalation, through exposure with skin, and through ingestion (Newman, 1980). Ingestion is the most common means and can occur through eating or drinking of high concentrations of pollutants. Bioaccumulation is the process of animals collecting and accumulating pollutant levels in their bodies over time. Other animals that prey on these animals would then be ingesting concentrated pollutants levels.

It is unlikely that the Project's emissions will cause injury or death to wildlife based on a review of the limited literature on air pollutant effects on wildlife. The Project's impacts are predicted to be very low and dispersed over a large area. Coupled with the mobility of wildlife, the potential for exposure of wildlife to the Project's impacts under weather conditions that lead to high concentrations is extremely unlikely.

In addition, no visibility impairment in the Project's vicinity is expected due to the types and quantities of emissions proposed for the Project. The opacity of the proposed exhaust emissions for both simple and combined cycle operation will be 10 percent or less.

7.3 IMPACTS TO PSD CLASS I AREAS

7.3.1 IDENTIFICATION OF AQRVS AND METHODOLOGY

An Air Quality Related Values (AQRV) analysis was conducted to assess the potential risk to AQRVs at the Everglades NP due to the proposed emissions from the Project. The Everglades NP is the closest Class I area to the Martin Plant site, and is located about 144 km south of the project site.

The U.S. Department of the Interior in 1978 administratively defined AQRVs to be:

> All those values possessed by an area except those that are not affected by changes in air quality and include all those assets of an area whose vitality, significance, or integrity is dependent in some way upon the air environment. These values include visibility and those scenic, cultural, biological, and recreational resources of an area that are affected by air quality.
>
> Important attributes of an area are those values or assets that make an area significant as a national monument, preserve, or primitive area. They are the assets that are to be preserved if the area is to achieve the purposes for which it was set aside (Federal Register 1978).

The AQRVs include freshwater and coastal wetlands, dominant plant communities, unique and rare plant communities, soils and associated periphyton, and the wildlife dependent on these communities for habitat. Rare, endemic, threatened, and endangered species of the national park and bioindicators of air pollution (e.g., lichens) are also evaluated.

The maximum predicted atmospheric concentrations due to the increase in emissions resulting from the proposed project are presented in Table 7-1. As shown, the predicted increase in impacts is very low for all pollutants considered.

7.3.2 IMPACTS TO SOILS

For soils, the potential and hypothesized effects of atmospheric deposition include:

- Increased soil acidification,
- Alteration in cation exchange,
- Loss of base cations, and
- Mobilization of trace metals.

The potential sensitivity of specific soils to atmospheric inputs is related to two factors. First, the physical ability of a soil to conduct water vertically through the soil profile is important in influencing the interaction with deposition. Second, the ability of the soil to resist chemical changes, as measured in terms of pH and soil cation exchange capacity (CEC), is important in determining how a soil responds to atmospheric inputs.

The soils of the Everglades NP are generally classified as histosols or entisols. Histosols (peat soils) are organic and have extremely high buffering capacities based on their CEC, base saturation, and bulk density. Therefore, they would be relatively insensitive to atmospheric inputs. The entisols are shallow sandy soils overlying limestone, such as the soils found in the pinelands. The direct connection of these soils with subsurface limestone tends to neutralize any acidic inputs. Moreover, the groundwater table is highly buffered due to the interaction with subsurface limestone formations, which results in high alkalinity (as $CaCO_3$).

The relatively low sensitivity of the soils to acid inputs coupled with the extremely low ground-level concentrations of contaminants projected for the Everglades NP from the Project emissions precludes any significant impact on soils.

7.3.3 IMPACTS TO VEGETATION

In general, the effects of air pollutants on vegetation occur primarily from SO_2, NO_2, O_3, and PM. Effects from minor air contaminants, such as fluoride, chlorine, hydrogen chloride, ethylene, ammonia, hydrogen sulfide, CO, and pesticides, have also been reported in the literature. The effects of air pollutants are dependent both on the concentration of the contaminant and the duration of the exposure. The term "injury," as opposed to damage, is commonly used to describe all plant responses to air contaminants and will be used in the context of this analysis. Air contaminants are thought to interact primarily with plant foliage, which is considered to be the major pathway of exposure. For purposes of this analysis, it was assumed that 100 percent of each air contaminant of concern is accessible to the plants.

Injury to vegetation from exposure to various levels or air contaminants can be termed acute, physiological, or chronic. Acute injury occurs as a result of a short-term exposure to a high contaminant concentration and is typically manifested by visible injury symptoms ranging from chlorosis (discoloration) to necrosis (dead areas). Physiological or latent injury occurs as the result of a long-term exposure to contaminant concentrations below that which results in acute injury symptoms. Chronic injury results from repeated exposure to low concentrations over extended periods of time, often without any visible symptoms, but with some effect on the overall growth and productivity of the plant. In this assessment, 100 percent of the particular air pollutant in the ambient air was assumed to interact with the vegetation, which is a very conservative approach.

The concentrations of the pollutants, duration of exposure and frequency of exposures influence the response of vegetation to atmospheric pollutants. The pattern of pollutant exposure expected from the facility is that of a few episodes of relatively high ground-level concentration, which occur during certain meteorological conditions interspersed with long periods of extremely low ground-level concentrations. If there are any effects of stack emissions on plants, they will be from the short-term, higher doses. A dose is the product of the concentration of the pollutant and duration of the exposure.

Sulfur Dioxide

Sulfur is an essential plant nutrient usually taken up as sulfate ions by the roots from the soil solution. When sulfur dioxide in the atmosphere enters the foliage through pores in the leaves, it reacts with water in the leaf interior to form sulfite ions. Sulfite ions are highly toxic. They interact with enzymes, compete with normal metabolites, and interfere with a variety of cellular functions (Horsman and Wellburn, 1976). However, within the leaf, sulfite is oxidized to sulfate ions, which can then be used by the plant as a nutrient. Small amounts of sulfite may be oxidized before they prove harmful.

Observed SO_2 effect levels for several plant species and plant sensitivity groupings are presented in Tables 7-2 and 7-3, respectively. SO_2 gas at elevated levels has long been known to cause injury to plants. Acute SO_2 injury usually develops within a few hours or days of exposure, and symptoms include marginal, flecked, and/or intercostal necrotic areas that appear water-soaked and dullish green initially. This injury generally occurs to younger leaves. Chronic injury usually is evident by signs of chlorosis, bronzing, premature senescence, reduced growth, and possible tissue necrosis (EPA, 1982). Background levels of SO_2 range from 2.5 to 25 $\mu g/m^3$.

Many studies have been conducted to determine the effects of high-concentration, short-term SO_2 exposure on natural community vegetation. Sensitive plants include ragweed, legumes, blackberry, southern pine, and red and black oak. These species are injured by exposure to 3-hour SO_2 concentrations of 790 to 1,570 $\mu g/m^3$. Intermediate plants include locust and sweetgum. These species are injured by exposure to 3-hour SO_2 concentrations of 1,570 to 2,100 µg/m^3. Resistant species (injured at concentrations above 2,100 µg/m^3 for 3 hours) include white oak and dogwood (EPA, 1982).

A study of native Floridian species (Woltz and Howe, 1981) demonstrated that cypress, slash pine, live oak, and mangrove exposed to 1,300 µg/m^3 SO_2 for 8 hours were not visibly damaged. This finding support the levels cited by other researchers on the effects of SO_2 on vegetation. A corroborative study (McLaughlin and Lee, 1974) demonstrated that approximately 20 percent of a cross-section of plants ranging from sensitive to tolerant was visibly injured at 3-hour SO_2 concentrations of 920 µg/m^3.

Two lichen species indigenous to the park area exhibited signs of SO_2 damage in the form of decreased biomass gain and photosynthetic rate as well as membrane leakage when exposed to concentrations of 200 to 400 µg/m^3 for 6 hours/week for 10 weeks (Hart *et al.*, 1988).

Jack pine seedlings exposed to SO_2 concentrations of 470 to 520 µg/m^3 for 24 hours demonstrated inhibition of foliar lipid synthesis; however, this inhibition was reversible (Malhotra and Kahn, 1978). Black oak exposed to 1,310 µg/m^3 SO_2 for 24 hours a day for 1 week demonstrated a 48 percent reduction in photosynthesis (Carlson, 1979).

The maximum 3-, 8-, and 24-hour average SO_2 concentrations for the Project are predicted to be 0.80, 0.56, and 0.39 µg/m^3, respectively, at the Class I area. The maximum 3-hour average SO_2 concentrations predicted for the Project at the Class I areas are 0.4 percent or less of those that caused damage to the most sensitive lichens. The modeled annual incremental increase in SO_2 adds slightly to background levels of this gas and poses only a minimal threat to area vegetation.

Nitrogen Dioxide

Nitrogen dioxide (NO_2) is another emission of concern for the proposed plant expansion. This compound can injure plant tissue with symptoms usually appearing as irregular white to brown collapsed lesions between the leaf veins and near the margins. Conversely, non-injurious levels of NO_2 can be absorbed by plants, enzymatically transformed into ammonia, and incorporated into plant constituents such as amino acids (Matsumaru *et al.*, 1979).

Plant damage can occur through either acute (short-term, high concentration) or chronic (long-term, relatively low concentration) exposure. For plants that have been determined to be more sensitive to NO_2 exposure than others, acute (1, 4, 8 hours) exposure caused 5 percent predicted foliar injury at concentrations ranging from 3,800 to 15,000 $\mu g/m^3$ (Heck and Tingey, 1979). Chronic exposure of selected plants (some considered NO_2-sensitive) to NO_2 concentrations of 2,000 to 4,000 $\mu g/m^3$ for 213 to 1,900 hours caused reductions in yield of up to 37 percent and some chlorosis (Zahn, 1975).

The maximum 1-, 3-, and 8-hour average NO_2 concentrations due to the Project are predicted to be 2.2, 2.0, and 1.4 $\mu g/m^3$, respectively, at the Class I area. These concentrations are approximately 0.015 to 0.06 percent of the levels that could potentially injure 5 percent of the plant foliage. For a chronic exposure, the maximum annual NO_2 concentration due to the Project is predicted to be 0.0017 $\mu g/m^3$ at the Class U area, which is 0.00005 to 0.0001 percent of the levels that caused minimal yield loss and chlorosis in plant tissue.

Although it has been shown that simultaneous exposure to SO_2 and NO_2 results in synergistic plant injury (Ashenden and Williams, 1980), the magnitude of this response is generally only 3 to 4 times greater than either gas alone and usually occurs at unnaturally high levels of each gas. Therefore, the concentrations within the park are still far below the levels that potentially cause plant injury for either acute or chronic exposure.

Particulate Matter

Although information pertaining to the effects of PM on plants is scarce, baseline concentrations are available (Mandoli and Dubey, 1988). Ten species of native Indian plants were exposed to levels of PM that ranged from 210 to 366 $\mu g/m^3$ for an 8-hour averaging period. Damage in the form of a higher leaf area/dry weight ratio was observed at varying degrees for most plants tested. Concentrations of PM lower than 163 $\mu g/m^3$ did not appear to be injurious to the tested plants.

The maximum 8-hour PM concentration due to the Project is predicted to be 0.23 $\mu g/m^3$ at the Class I area. This concentration is approximately 0.06 to 0.14 percent of the values that affected plant foliage. As a result, no significant effects to vegetative AQRVs are expected from the Project's emissions.

Carbon Monoxide

As with PM, information pertaining to the effects of CO on plants is scarce. The main effect of high concentrations of CO is the inhibition of cytochrome *c* oxidase, the terminal oxidase in the mitochondrial electron transfer chain. Inhibition of cytochrome *c* oxidase depletes the supply of ATP, the principal donor of free energy required for cell functions. However, this inhibition only occurs at extremely high concentrations of CO. Pollok *et al.* (1989) reported that exposure to $CO{:}O_2$ ratio of 25 (equivalent to an ambient CO concentration of 6.85 x 10^6 $\mu g/m^3$) resulted in stomatal closure in the leaves of the sunflower (*Helianthus annuus*). Naik *et al.* (1992) reported cytochrome *c* oxidase inhibition in corn, sorghum, millet, and Guinea grass at $CO{:}O_2$ ratios of 2.5 (equivalent to an ambient CO concentration of 6.85 x 10^5 $\mu g/m^3$). These plants were considered the species most sensitive to CO-induced inhibition of cytochrome *c* oxidase.

The maximum 1-hour average concentration due to the Project is 0.86 $\mu g/m^3$ in the Class I area which is less than 0.001 percent of the minimum value that caused inhibition in laboratory studies. The amount of damage sustained at this level, if any, for 1 hour would have negligible effects over an entire growing season. The maximum predicted annual concentration of 0.0086 $\mu g/m^3$ reflects more realistic, yet conservative, CO level for the Class I areas. This maximum concentration is predicted to be less than 0.00001 percent of the value that caused cytochrome *c* oxidase inhibition.

Sulfuric Acid Mist

Acidic precipitation or acid rain is coupled to SO_2 emissions mainly formed during the burning of fossil fuels. This pollutant is oxidized in the atmosphere and dissolves in rain forming sulfuric acid mist which falls as acidic precipitation (Ravera, 1989). Although concentration data are not available, sulfuric acid mist has been reported to yield necrotic spotting on the upper surfaces of leaves (Middleton *et al.*, 1950).

No significant adverse effects on vegetation are expected from the project's emissions because SO_2 concentrations, which lead directly to the formation of sulfuric acid mist concentrations, are predicted to be well below levels which have been documented as negatively affecting vegetation. During the last decade, much attention has been focused on acid rain. Acidic deposition is an ecosystem-level problem that affects vegetation because of some alterations of soil conditions such as increased leaching of essential base cations or elevated concentrations of aluminum in the soil water (Goldstein *et al.*, 1985). Although effects of acid rain in eastern North America have been well published and publicized, detrimental effects of acid rain on Florida vegetation are lacking documentation.

Summary

In summary, the phytotoxic effects on the Everglades NP from proposed project's emissions are expected to be minimal. It is important to note that the substances were evaluated with the assumption that 100 percent was available for plant uptake. This is rarely the case in a natural ecosystem.

7.3.4 IMPACTS TO WILDLIFE

A wide range of physiological and ecological effects to fauna has been reported for gaseous and particulate pollutants (Newman, 1981; Newman and Schreiber, 1988). The most severe of these effects have been observed at concentrations above the secondary ambient air quality standards. Physiological and behavioral effects have been observed in experimental animals at or below these standards. No observable effects to fauna are expected at concentrations below the values reported in Table 7-4.

The major air quality risk to wildlife in the United States is from continuous exposure to pollutants above the National Ambient Air Quality Standards. This occurs in non-attainment areas, e.g., Los Angeles Basin. Risks to wildlife also may occur for wildlife living in the vicinity of an emission source that experiences frequent upsets or episodic conditions resulting from malfunctioning equipment, unique meteorological conditions, or startup operations (Newman and Schreiber, 1988). Under these conditions, chronic effects (e.g., particulate contamination) and acute effects (e.g., injury to health) have been observed (Newman, 1981).

For impacts on wildlife, the lowest threshold values of SO_2, NO_x, and particulates that are reported to cause physiological changes are shown in Table 7-4. These values are up to orders of magnitude larger than maximum predicted concentrations for the Class I area.

No significant effects on wildlife AQRVs from SO_2, NO_x, and particulates are expected. These results are considered indications of the risk of other air pollutant emissions predicted from the Project which is also considered to be negligible.

7.4 IMPACTS ON VISIBILITY

7.4.1 INTRODUCTION

The CAA Amendments of 1977 provide for implementation of guidelines to prevent visibility impairment in mandatory Class I areas. The guidelines are intended to protect the aesthetic quality of these pristine areas from reduction in visual range and atmospheric discoloration due to various pollutants. Sources of air pollution can cause visible plumes if emissions of PM_{10} and NO_x are sufficiently large. A plume will be visible if its constituents scatter or absorb sufficient light so that the plume is brighter or darker than its viewing background (e.g., the sky or a terrain feature, such as a mountain). PSD Class I areas, such as national parks and wilderness areas, are afforded special visibility protection designed to prevent plume visual impacts to observers within a Class I area.

Visibility is an AQRV for the Everglades NP. Visibility can take the form of plume blight for nearby areas or regional haze for long distances (e.g., distances beyond 50 km). Because the Everglades NP is more than 50 km from the Project, the change in visibility is analyzed as regional haze.

Currently, there are several air quality modeling approaches recommended by the Interagency Workgroup on Air Quality Models (IWAQM) to perform these analyses. The IWAQM consists of EPA and FLM of Class I areas who are responsible for ensuring that AQRVs are not adversely impacted by new and existing sources. These recommendations have been summarized in two documents:

- *Interagency Workgroup on Air Quality Models (IWAQM), Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts* (EPA, 1998), referred to as the IWAQM Phase 2 report; and
- *Federal Land Managers' Air Quality Related Values Workgroup (FLAG), Phase I Report,* USFS, NPS, USFWS (December, 2000), referred to as the FLAG document.

The methods and assumptions recommended in these documents were used to assess visibility impairment due to the project.

7.4.2 ANALYSIS METHODOLOGY

Methodology

Based on the FLAG document, current regional haze guidelines characterize a change in visibility by the 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. An index that simply quantifies the percent change in visibility due to the operation of a source is calculated as:

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

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

The purpose of the visibility analysis is to calculate the extinction at each receptor for each day (24-hour period) of the year due to the proposed Project. The criteria to determine if the Project's impacts are potentially significant are based on a change in extinction of 5 percent or greater for any day of the year.

Processing of visibility impairment for this study was performed with the CALPUFF model (see Appendix D) and the CALPUFF post-processing program CALPOST. The analysis was conducted in accordance with the most recent guidance from the FLAG report (December 2000). The CALPUFF postprocessor model CALPOST is used to calculate the combined visibility effects from the different pollutants that are emitted from the Project. Daily background extinction coefficients are calculated on a hour-by-hour basis using hourly relative humidity data from CALMET and hygroscopic and non-hygroscopic extinction components specified in the FLAG document. For the Class I area evaluated, the hygroscopic and non-hygroscopic components are 0.9 and 8.5 inverse mega meter (Mm^{-1}). CALPOST then predicts the percent extinction change for each day of the year.

Results

The results of the refined regional haze analysis are presented in Table 7-5. The results indicate that the proposed Project's maximum predicted impact on visibility at the Everglades NP is 2.75 percent for the combined-cycle operation on fuel oil. The maximum predicted impact on visibility when firing natural gas is 0.64 percent. The values are below the FLM's screening criteria of 5 percent change. Therefore, the Project is not expected to have an adverse impact on the existing regional haze in the Everglades NP.

7.4.3 SULFUR AND NITROGEN DEPOSITION

General Methods

As part of the AQRV analyses, total nitrogen (N) and sulfur (S) deposition rates were predicted at the Everglades NP Class I area. The deposition analysis thresholds (DAT) are based on the annual averaging period. The total deposition is estimated in units of kilogram per hectare per year (kg/ha/yr) of nitrogen or sulfur. The CALPUFF model is used to predict wet and dry deposition fluxes of various oxides of these elements.

For N deposition, the species include:

- Particulate ammonium nitrate (from species NO_3), wet and dry deposition;
- Nitric acid (species HNO_3), wet and dry deposition;
- NO_x, dry deposition; and
- Ammonium sulfate (species SO_4), wet and dry deposition.

For S deposition, the species include:

- SO2, wet and dry deposition; and
- SO4, wet and dry deposition.

The CALPUFF model produces results in units of $\mu g/m^2/s$. The modeled deposition rates are then converted to N or S deposition in kg/ha respectively, by using a multiplier equal to the ratio of the molecular weights of the substances (IWAQM Phase II report Section 3.3).

Deposition analysis thresholds (DAT) for nitrogen and sulfur deposition of 0.01 kg/ha/yr were provided by the U.S. Fish and Wildlife Service (January 2002). A DAT is the additional amount of N or S deposition within a Class I area, below which estimated impacts from a proposed new or modified source are considered insignificant. The maximum N and S depositions predicted for the Project are, therefore, compared to these DAT or significant impact levels.

Results

The maximum predicted N and S depositions predicted for the Project in the PSD Class I area of the Everglades NP are summarized in Table 7-6. The maximum N and S deposition rates for the Project are predicted to be 0.0015 and 0.0004 kg/ha/yr, respectively. These maximum deposition rates are below the significant impact levels for N and S of 0.01 kg/ha/yr. As a result, the Project's emissions are not expected to have a significant adverse effect on N and S deposition at the Class I area.

Table 7-1. Maximum Pollutant Concentrations Predicted for the Project at the PSD Class I Area of the Everglades NP

Pollutant	Averaging Time	Maximum Concentrations ($\mu g/m^3$) [a]		
		Natural Gas	Fuel Oil	Natural Gas/ Fuel Oil
Combined-Cycle Operation [b]				
SO_2	Annual [c]	NM	NM	0.0013
	24-Hour	0.052	0.388	0.388
	8-Hour	0.082	0.556	0.556
	3-Hour	0.11	0.803	0.803
	1-Hour	0.139	0.902	0.902
PM_{10}	Annual [c]	NM	NM	0.0018
	24-Hour	0.086	0.174	0.174
	8-Hour	0.126	0.230	0.230
	3-Hour	0.170	0.334	0.334
	1-Hour	0.216	0.379	0.379
NO_2	Annual [c]	NM	NM	0.0017
	24-Hour	0.093	0.254	0.254
	8-Hour	0.186	0.458	0.458
	3-Hour	0.252	0.667	0.667
	1-Hour	0.302	0.726	0.726
CO	Annual [c]	NM	NM	0.0086
	24-Hour	0.346	0.309	0.346
	8-Hour	0.499	0.402	0.499
	3-Hour	0.677	0.586	0.677
	1-Hour	0.86	0.679	0.86
Simple-Cycle Operation [b]				
SO_2	Annual [c]	NM	NM	0.0013
	24-Hour	0.035	0.338	0.338
	8-Hour	0.051	0.499	0.499
	3-Hour	0.074	0.716	0.716
	1-Hour	0.081	0.787	0.787
PM_{10}	Annual [c]	NM	NM	0.0018
	24-Hour	0.039	0.069	0.069
	8-Hour	0.054	0.096	0.096
	3-Hour	0.074	0.133	0.133
	1-Hour	0.081	0.146	0.146
NO_2	Annual [c]	NM	NM	0.0017
	24-Hour	0.245	0.793	0.793
	8-Hour	0.452	1.439	1.439
	3-Hour	0.636	2.019	2.019
	1-Hour	0.398	2.234	2.234
CO	Annual [c]	NM	NM	0.0086
	24-Hour	0.185	0.259	0.259
	8-Hour	0.259	0.363	0.363
	3-Hour	0.363	0.509	0.509
	1-Hour	0.398	0.559	0.559

Note: NM = not modeled

[a] Concentrations are highest predicted using CALPUFF model and 1990 CALMET wind field for south Florida.

[b] Concentrations predicted for combined- and simple cycle operation are based on the operating scenario with the maximum hourly emissions. For both natural gas- and oil-firing, maximum emissions are based on the combustion turbines operating for baseload conditions at an ambient temperature of 35°F.

For combined cycle operation and natural gas-firing, duct burner emission are included. For simple cycle operation and natural gas-firing, combustion turbines are assumed to operate at higher power mode.

[c] Annual average concentrations are based on the operating scenarios with the maximum hourly emissions for the following annual hours:

1. For SO_2 and PM_{10}: combined cycle operation with natural gas- and fuel oil-firing for 8,260 and 500 hours, respectively;
2. For NO_2: combined cycle operation with natural gas-firing for 7,760; simple cycle operation with natural gas- and fuel oil-firing for 500 hours each; and
3. For CO: combined cycle operation with natural gas-firing for 8,760.

Table 7-2. SO_2 Effects Levels for Various Plant Species

Plant Species	Observed Effect Level ($\mu g/m^3$)	Exposure (Time)	Reference
Sensitive to tolerant	920 (20 percent displayed visible injury)	3 hours	McLaughlin and Lee, 1974
Lichens	200-400	6 hr/wk for 10 weeks	Hart *et al.*, 1988
Cypress, slash pine, live oak, mangrove	1,300	8 hours	Woltz and Howe, 1981
Jack pine seedlings	470-520	24 hours	Malhotra and Kahn, 1978
Black oak	1,310	Continuously for 1 week	Carlson, 1979

Table 7-3. Sensitivity Groupings of Vegetation Based on Visible Injury at Different SO_2 Exposures[a]

Sensitivity Grouping	SO_2 Concentration		Plants
	1-Hour	3-Hour	
Sensitive	1,310 - 2,620 μG/m^3 (0.5 - 1.0 ppm)	790 - 1,570 μG/m^3 (0.3 - 0.6 ppm)	Ragweeds Legumes Blackberry Southern pines Red and black oaks White ash Sumacs
Intermediate	2,620 - 5,240 μG/m^3 (1.0 - 2.0 ppm)	1,570 - 2,100 μG/m^3 (0.6 - 0.8 ppm)	Maples Locust Sweetgum Cherry Elms Tuliptree Many crop and garden species
Resistant	>5,240 μG/m^3 (>2.0 ppm)	>2,100 μG/m^3 (>0.8 ppm)	White oaks Potato Upland cotton Corn Dogwood Peach

[a] Based on observations over a 20-year period of visible injury occurring on over 120 species growing in the vicinities of coal-fired power plants in the southeastern United States.

Source: EPA, 1982a.

Table 7-4. Examples of Reported Effects of Air Pollutants at Concentrations Below National Secondary Ambient Air Quality Standards

Pollutant	Reported Effect	Concentration ($\mu g/m^3$)	Exposure
Sulfur Dioxide[a]	Respiratory stress in guinea pigs	427 to 854	1 hour
	Respiratory stress in rats	267	7 hours/day; 5 day/week for 10 weeks
	Decreased abundance in deer mice	13 to 157	continually for 5 months
Nitrogen Dioxide[b,c]	Respiratory stress in mice	1,917	3 hours
	Respiratory stress in guinea pigs	96 to 958	8 hours/day for 122 days
Particulates[a]	Respiratory stress, reduced respiratory disease defenses	120 PbO_3	continually for 2 months
	Decreased respiratory disease defenses in rats, same with hamsters	100 $NiCl_2$	2 hours

Source: a Newman and Schreiber, 1988.
b Gardner and Graham, 1976.
c Trzeciak et al., 1977.

Table 7-5. Maximum 24-hour Average Visibility Impairment Predicted for the Project at the PSD Class I Area of the Everglades NP

Operating Mode	Maximum Visibility Impairment (%) [a] Natural Gas	Fuel Oil	Visibility Impairment Criteria (%)
Combined-Cycle	0.64	2.75	5.0
Simple-Cycle	0.41	1.91	5.0

[a] Concentrations are highest predicted using CALPUFF model and 1990 CALMET wind field for south Florida. Background extinctions calculated using FLAG Document (December 2000) values and hourly relative humidity data.

[b] Concentrations predicted for combined- and simple cycle operation are based on the operating scenario with the maximum hourly emissions. For both natural gas- and oil-firing, maximum emissions are based on the combustion turbines operating for baseload conditions at an ambient temperature of 35°F.

For combined cycle operation and natural gas-firing, duct burner emission are included. For simple cycle operation and natural gas-firing, combustion turbines are assumed to operate at higher power mode.

Table 7-6. Maximum Sulfur and Nitrogen Annual Deposition Predicted for the Project at the PSD Class I Area of the Everglades NP

	Maximum Deposition (µg/m2/s)			Species Molecular Weight	Conversion of Species to Nitrogen (N) or Sulfur (S)					Deposition (kg/ha/yr)[a]		Deposition Analysis Threshold[b]
Species	Dry	Wet	Total	(MW)	Basis	Deposition Molecule	No. of Deposition Molecules	Deposition Molecule MW	Ratio MW Dep. Molecule to Species	N	S	(kg/ha/yr)
Nitrogen (N) Deposition												
Nitrate (NO_3)	1.809E-08	6.792E-07	6.973E-07	62	Ammonium nitrate (NH_4NO_3)	N	2	28	0.452	0.00010		
Nitric acid (HNO_3)	4.189E-06	8.249E-06	1.244E-05	63	HNO_3	N	1	14	0.222	0.00087		
Nitrogen oxides (NOx as NO_2)	2.771E-06	NA	2.771E-06	46	NO_2	N	1	14	0.304	0.00027		
Sulfate (SO_4)	3.889E-08	2.928E-06	2.967E-06	96	Ammonium sulfate ($(NH_4)_2SO_4$)	N	2	28	0.292	0.00027		
TOTAL										0.0015		0.01
Sulfur (S) Deposition												
Sulfur dioxide (SO_2)	3.897E-06	4.328E-06	8.532E-07	64	SO_2	S	1	32	0.500		0.00013	
Sulfate (SO_4)	3.889E-08	2.928E-06	2.967E-06	96	Ammonium sulfate ($(NH_4)_2SO_4$)	S	1	32	0.333		0.00031	
TOTAL											0.0004	0.01

[a] Deposition is calculated by multiplying maximum predicted total deposition (µg/m²/s) for total species by ratio of molecular weights of deposition molecule to species by conversion factor.
Conversion factor is used to convert µg/m²/s to kg/hectare (ha)/yr using following units:

µg/m²/s x	0.000001	g/µg
x	0.001	kg/g
x	10000	m²/hectare
x	3600	sec/hr
x	8760	hr/yr =kg/ha/yr
or		
µg/m²/s x	315.36 =	kg/ha/yr

[b] Deposition analysis thresholds (DAT) for nitrogen and sulfur deposition provided by the U.S. Fish and Wildlife Service, January 2002.
A DAT is the additional amount of N or S deposition within a Class I area, below which estimated impacts from a proposed new or modified source are considered insignificant.

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APPENDIX A

EXPECTED PERFORMANCE AND EMISSION INFORMATION ON "F" CLASS COMBUSTION TURBINE

(Note: SO_2 based on 0.2 gr/100 cf of H_2S. Actual total sulfur based on 1 gr/100 cf to account for odorant (mercaptans) in pipeline gas.)

Table A-1. Design Information and Stack Parameters for FPL Martin Unit 8 Combined-Cycle Project
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, Base Load

Parameter	CT Only Turbine Inlet Temperature					CT with Duct Burner Turbine Inlet Temperature				
	35 °F Case 8	59 °F Case 6	75 °F Case 4	80 °F Power Aug.	95 °F Case 2	35 °F w/DB Case 7	59 °F w/DB Case 5	75 °F w/DB Case 3	80 °F w/DB Power Aug.	95 °F w/DB Case 1
Combustion Turbine Performance										
Net power output (MW)	181.64	172.44	163.14	164.44	149.74	181.64	172.44	163.14	164.44	149.74
Net heat rate (Btu/kWh, LHV)	9,213	9,280	9,412	9440	9,666	9,213	9,280	9,412	9440	9,666
(Btu/kWh, HHV)	10,227	10,301	10,447	10,481	10,729	10,227	10,301	10,447	10,481	10,729
Heat Input (MMBtu/hr, LHV)	1,674	1,600	1,536	1552.7	1,447	1,674	1,600	1,536	1552.7	1,447
(MMBtu/hr, HHV)	1,858	1,776	1,704	1,723	1,607	1,858	1,776	1,704	1,723	1,607
Inlet Fogger	Off	Off	Off	On	Off	Off	Off	Off	On	Off
Relative Humidity (%)	20	60	60		50	20	60	60		50
Fuel heating value (Btu/lb, LHV)	20,835	20,835	20,835	20,835	20,835	20,835	20,835	20,835	20,835	20,835
(Btu/lb, HHV)	23,127	23,127	23,127	23,127	23,127	23,127	23,127	23,127	23,127	23,127
(HHV/LHV)	1.110	1.110	1.110	1.110	1.110	1.110	1.110	1.110	1.110	1.110
Duct Burner (DB)										
Heat input (MMBtu/hr, HHV)	0	0	0	0	0	550	550	550	550	550
(MMBtu/hr, LHV)	0	0	0	0	0	495.5	495.5	495.5	495.5	495.5
CT/DB Exhaust Flow										
Mass Flow (lb/hr)- with no margin	3,706,000	3,539,000	3,418,000	3,444,000	3,257,000	3,728,099.6	3,561,100	3,440,100	3,466,100	3,279,100
- provided	3,706,000	3,539,000	3,418,000	3,444,000	3,257,000					
Temperature (°F)	1,095	1,116	1,128	1,125	1,143	1,095	1,116	1,128	1,125	1,143
Moisture (% Vol.)	7.56	8.39	9.04	9.7	9.92	9.59	10.50	11.21	12.49	12.17
Oxygen (% Vol.)	12.60	12.44	12.36	12.19	12.27	10.35	10.10	9.94	10.34	9.75
Molecular Weight	28.49	28.39	28.33	28.25	28.22	28.36	28.26	28.18	29.68	28.08
Fuel Usage										
Fuel usage (lb/hr) = Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu (Fuel Heat Content, Btu/lb (LHV))										
Heat input (MMBtu/hr, LHV)	1,674	1,600	1,536	1,553	1,447	1,674	1,600	1,536	1,553	1,447
Heat content (Btu/lb, LHV)	20,835	20,835	20,835	20,835	20,835	20,835	20,835	20,835	20,835	20,835
Fuel usage (lb/hr)- calculated	80,322	76,808	73,698	74,524	69,470	80,322	76,808	73,698	74,524	69,470
Heat content (Btu/cf, LHV)- assumed	933	933	933	933	933	933	933	933	933	933
Fuel density (lb/ft^3)	0.0448	0.0448	0.0448	0.0448	0.0448	0.0448	0.0448	0.0448	0.0448	0.0448
Fuel usage (cf/hr)- calculated	1,792,892	1,714,470	1,645,047	1,663,474	1,550,662	1,792,892	1,714,470	1,645,047	1,663,474	1,550,662
Fuel Usage - Duct Burner Only										
Fuel usage (lb/hr)- calculated	0	0	0	0	0	23,782	23,782	23,782	23,782	23,782
Fuel usage (cf/hr)- calculated	0	0	0	0	0	530,846	530,846	530,846	530,846	530,846
CT/Bypass and HRSG Stack										
CT/Bypass-Stack height (ft)	80	80	80	80	80	80	80	80	80	80
Diameter (ft)	22	22	22	22	22	22	22	22	22	22
HRSG - Stack Height (ft)	120	120	120	120	120	120	120	120	120	120
Diameter (ft)	19	19	19	19	19	19	19	19	19	19
CT/Bypass Stack Flow Conditions										
Turbine Flow (acfm) = [(Mass Flow (lb/hr) x 1,545 x (Temp. (°F)+ 460°F)] / [Molecular weight x 2116.8] / 60 min/hr										
Mass flow (lb/hr)	3,706,000	3,539,000	3,418,000	3,444,000	3,257,000	NA	NA	NA	NA	NA
Temperature (°F)	1,095	1,116	1,128	1,125	1,143	NA	NA	NA	NA	NA
Molecular weight	28.49	28.39	28.33	28.25	28.22	NA	NA	NA	NA	NA
Volume flow (acfm)- calculated	2,460,544	2,389,462	2,331,000	2,350,164	2,250,314	NA	NA	NA	NA	NA
(ft^3/s)- calculated	41,009	39,824	38,850	39,169	37,505	NA	NA	NA	NA	NA
Diameter (ft)	22	22	22	22	22	NA	NA	NA	NA	NA
Velocity (ft/sec)- calculated	107.9	104.8	102.2	103.0	98.7	NA	NA	NA	NA	NA
HRSG Stack Flow Conditions										
Velocity (ft/sec) = Volume flow (acfm) / [((diameter)^2 /4) x 3.14159] / 60 sec/min										
Mass flow (lb/hr)	3,706,000	3,539,000	3,418,000	3,444,000	3,257,000	3,728,100	3,561,100	3,440,100	3,466,100	3,279,100
HRSG Stack Temperature (°F)	203	202	204	204	201	189	188	189	188	190
Molecular weight	28.49	28.39	28.33	28.25	28.22	28.36	28.26	28.18	29.68	28.08
Volume flow (acfm)	1,048,619	1,004,150	974,675	984,548	927,921	1,037,294	993,802	964,236	920,636	923,335
Diameter (ft)	19	19	19	19	19	19	19	19	19	19
Velocity (ft/sec)- calculated	61.6	59.0	57.3	57.9	54.5	61.0	58.4	56.7	54.1	54.3

Note: Universal gas constant = 1,545 ft-lb(force)/°R; atmospheric pressure = 2,116.8 lb(force)/ft^2; 14.7 lb/ft^3

Source: GE, 2000 - CT Performance Data; Golder Associates, 2001 - DB Calculations

Table A-2. Maximum Emissions for Criteria Pollutants for FPL Martin Unit 8 Combined-Cycle Project
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, Base Load

Parameter	CT Only Turbine Inlet Temperature					CT with Duct Burner Turbine Inlet Temperature				
	35 °F Case 8	59 °F Case 6	75 °F Case 4	80 °F Power Aug.	95 °F Case 2	35 °F w/DB Case 7	59 °F w/DB Case 5	75 °F w/DB Case 3	80 °F w/DB Power Aug.	95 °F w/DB Case 1
Particulate from CT, DB, and SCR										
Total PM_{10} = PM_{10} (front half) + PM_{10} ($(NH_4)_2SO_4$) from SCR only										
a. PM_{10} (front half) (lb/hr)										
CT- provided	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
DB (lb/hr) - calculated	0.0	0.0	0.0	0.0	0.0	5.5	5.5	5.5	5.5	5.5
Total CT/DB emission rate (lb/hr)	9.0	9.0	9.0	9.0	9.0	14.5	14.5	14.5	14.5	14.5
b. PM_{10} ($(NH_4)_2SO_4$) from SCR only = Sulfur trioxide from conversion of SO_2 converts to ammonium sulfate (= PM_{10})										
Particulate from conversion of SO_2 = SO_2 emissions (lb/hr) x conversion of SO_2 to SO_3 x lb SO_3/lb SO_2 x conversion of SO_3 to $(NH_4)_2SO_4$ x lb $(NH_4)_2SO_4$/ lb SO_3										
SO_2 emission rate (lb/hr)- calculated	10.2	9.8	9.4	9.5	8.9	13.3	12.8	12.4	12.5	11.9
Conversion (%) from SO_2 to SO_3	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8
MW SO_3/ SO_2 (80/64)	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Conversion (%) from SO_3 to $(NH_4)_2(SO_4)$	100	100	100	100	100	100	100	100	100	100
MW $(NH_4)_2$ SO_4/ SO_3 (132/80)	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
SCR Particulate (lb/hr)- calculated	2.07	1.98	1.90	1.92	1.79	2.68	2.59	2.51	2.53	2.40
Total CT/Bypass stack emission rate (lb/hr) [a]	9.0	9.0	9.0	9.0	9.0	NA	NA	NA	NA	NA
Total HRSG stack emission rate (lb/hr) [a + b]	11.1	11.0	10.9	10.9	10.8	17.2	17.1	17.0	17.0	16.9
(lb/mmBtu, HHV)	0.0060	0.0062	0.0064	0.0063	0.0067	0.0071	0.0073	0.0075	0.0075	0.0078
Sulfur Dioxide										
SO_2 (lb/hr)= Natural gas (scf/hr) x sulfur content(gr/100 scf) x 1 lb/7000 gr x (lb SO_2 /lb S) /100										
Fuel use (cf/hr)	1,792,892	1,714,470	1,645,047	1,663,474	1,550,662	2,323,738	2,245,316	2,175,893	2,194,320	2,081,507
Sulfur content (grains/ 100 cf)	2	2	2	2	2	2	2	2	2	2
lb SO_2 /lb S (64/32)	2	2	2	2	2	2	2	2	2	2
CT/Bypass stack emission rate (lb/hr)	10.2	9.8	9.4	9.5	8.9	NA	NA	NA	NA	NA
HRSG stack emission rate (lb/hr)	10.2	9.8	9.4	9.5	8.9	13.3	12.8	12.4	12.5	11.9
Nitrogen Oxides										
NOx (lb/hr) = NOx (ppmvd@ 15% O_2) x {[20.9 x (1-Moisture (%)/100] - Oxygen, dry(%)) x 2116.8 lb/ft^2 x Volume flow (acfm) x 46 (mole. wgt NOx) x 60 min/hr / [1545 x (CT temp.(°F) + 460) x (20.9-15) x 1,000,000 (adj. for ppm)]										
CT/DB, ppmvd @15% O_2	9	9	9	12	9	12.0	12.0	12.1	14.9	12.1
Moisture (%)	7.56	8.39	9.04	9.7	9.92	9.59	10.50	11.21	12.49	12.17
Oxygen (%)	12.6	12.44	12.36	12.19	12.27	10.35	10.10	9.94	10.34	9.75
Turbine Flow (acfm)	2,460,544	2,389,462	2,331,000	2,350,164	2,250,314	2,486,882	2,415,907	2,357,879	2,403,989	2,277,437
Turbine Exhaust Temperature (°F)	1,095	1,116	1,128	1,125	1,143	1,095	1,116	1,128	1,125	1,143
CT/DB Emission rate (lb/hr)	61.3	58.7	56.3	76.2	53.1	116.3	113.7	111.3	131.2	108.1
CT/Bypass Stack, ppmvd @ 15% O_2	9	9	9	12	9	NA	NA	NA	NA	NA
CT/Bypass Stack Emission rate (lb/hr)	61.3	58.7	56.3	76.2	53.1	NA	NA	NA	NA	NA
HRSG Stack, ppmvd @ 15% O_2	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
HRSG Stack Emission rate (lb/hr)	17.0	16.3	15.6	15.9	14.7	24.2	23.6	23.1	22.1	22.3
Carbon Monoxide										
CO (lb/hr) = CO(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft^2 x Volume flow (acfm) x 28 (mole. wgt CO) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]										
Basis, ppmvd	9	9	9	15	9	22.1	22.9	23.6	29.5	24.5
Basis, ppmvd @ 15% O2 - calculated	7.3	7.3	7.3	12.0	7.3	13.8	14.1	14.3	19.2	14.7
Moisture (%)	7.56	8.39	9.04	9.70	9.92	9.59	10.50	11.21	12.49	12.17
Oxygen (%)	12.60	12.44	12.36	12.19	12.27	10.35	10.10	9.94	10.34	9.75
Turbine Flow (acfm)	2,460,544	2,389,462	2,331,000	2,350,164	2,250,314	2,486,882	2,415,907	2,357,879	2,403,989	2,277,437
Turbine Exhaust Temperature (°F)	1,095	1,116	1,128	1,125	1,143	1,095	1,116	1,128	1,125	1,143
CT/DB Emission rate (lb/hr)	28.6	27.5	26.6	45.0	25.5	72.6	71.5	70.6	89.0	69.5
CT/Bypass Stack Emission rate (lb/hr)	28.6	27.5	26.6	45.0	25.5	NA	NA	NA	NA	NA
HRSG Stack Emission rate (lb/hr)	28.6	27.5	26.6	45.0	25.5	72.6	71.5	70.6	89.0	69.5

Table A-2. Maximum Emissions for Criteria Pollutants for FPL Martin Unit 8 Combined-Cycle Project
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, Base Load

Parameter	CT Only Turbine Inlet Temperature					CT with Duct Burner Turbine Inlet Temperature				
	35 °F Case 8	59 °F Case 6	75 °F Case 4	80 °F Power Aug.	95 °F Case 2	35 °F w/DB Case 7	59 °F w/DB Case 5	75 °F w/DB Case 3	80 °F w/DB Power Aug.	95 °F w/DB Case 1
Volatile Organic Compounds										
VOCs (lb/hr) = VOC(ppmvd) x [1-Moisture(%)/100] x 2116.8 lb/ft^2 x Volume flow (acfm) x 16 (mole. wgt as methane) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]										
Basis, ppmvw	1.5	1.5	1.5	1.5	1.5	6.2	6.5	6.7	6.6	7.0
Basis, ppmvd @ 15% O2 - calculated	1.3	1.3	1.3	1.3	1.3	4.3	4.4	4.6	4.9	4.8
Moisture (%)	7.56	8.39	9.04	9.70	9.92	9.59	10.50	11.21	12.49	12.17
Oxygen (%)	12.60	12.44	12.36	12.19	12.27	10.35	10.10	9.94	10.34	9.75
Turbine Flow (acfm)	2,460,544	2,389,462	2,331,000	2,350,164	2,250,314	2,486,882	2,415,907	2,357,879	2,403,989	2,277,437
Turbine Exhaust Temperature (°F)	1,095	1,116	1,128	1,125	1,143	1,095	1,116	1,128	1,125	1,143
CT/DB Emission rate (lb/hr)	2.89	2.74	2.63	2.64	2.49	11.69	11.54	11.43	11.44	11.29
CT/Bypass Stack Emission rate (lb/hr)	2.89	2.74	2.63	2.64	2.49	NA	NA	NA	NA	NA
HRSG Stack Emission rate (lb/hr)	2.89	2.74	2.63	2.64	2.49	11.69	11.54	11.43	11.44	11.29
Sulfuric Acid Mist										
Sulfuric Acid Mist (lb/hr)= SO_2 emission (lb/hr) x Conversion to H_2SO_4 (% by weight)/100										
CT SO_2 emission rate (lb/hr) - provided	10.2	9.8	9.4	9.5	8.9	10.2	9.8	9.4	9.5	8.9
CT Conversion to H_2SO_4 (% by weight) - provided	10	10	10	10	10	10	10	10	10	10
DB SO_2 emission rate (lb/hr) - provided	0	0	0	0	0	3.0	3.0	3.0	3.0	3.0
DB Conversion to H_2SO_4 (%) - provided	20	20	20	20	20	20	20	20	20	20
CT/Bypass Stack Emission rate (lb/hr)	1.02	0.98	0.94	0.95	0.89	NA	NA	NA	NA	NA
HRSG Stack Emission rate (lb/hr)	1.02	0.98	0.94	0.95	0.89	1.63	1.59	1.55	1.56	1.49
Lead										
Lead (lb/hr) = NA										
Emission Rate Basis	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Emission rate (lb/hr)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

Note: ppmvd= parts per million, volume dry; O_2= oxygen.

Source: GE, 2000 - CT Performance Data; Golder Associates, 2001 - DB Calculations

Table A-3. Design Information and Stack Parameters for FPL Martin Unit 8 Combined-Cycle Project
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 75% Load

Parameter	Turbine Inlet Temperature 35 °F Case 12	59 °F Case 11	75 °F Case 10	95 °F Case 9
Combustion Turbine Performance				
Net power output (MW)	136.7	129.24	122.24	112.24
Net heat rate (Btu/kWh, LHV)	9,855	10,043	10,236	10,602
(Btu/kWh, HHV)	10,939	11,148	11,362	11,769
Heat Input (MMBtu/hr, LHV)	1,347	1,298	1,251	1,190
(MMBtu/hr, HHV)	1,495	1,441	1,389	1,321
Relative Humidity (%)	20	60	60	50
Fuel heating value (Btu/lb, LHV)	20,835	20,835	20,835	20,835
(Btu/lb, HHV)	23,127	23,127	23,127	23,127
(HHV/LHV)	1.110	1.110	1.110	1.110
CT Exhaust Flow				
Mass Flow (lb/hr)- with no margin	2,979,000	2,888,000	2,803,000	2,694,000
- provided	2,979,000	2,888,000	2,803,000	2,694,000
Temperature (°F)	1,122	1,139	1,153	1,170
Moisture (% Vol.)	7.49	8.27	8.92	9.8
Oxygen (% Vol.)	12.67	12.57	12.49	12.41
Molecular Weight	28.50	28.41	28.33	28.23
Fuel Usage				
Fuel usage (lb/hr) = Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu (Fuel Heat Content, Btu/lb (LHV))				
Heat input (MMBtu/hr, LHV)	1,347	1,298	1,251	1,190
Heat content (Btu/lb, LHV)	20,835	20,835	20,835	20,835
Fuel usage (lb/hr)- calculated	64,660	62,299	60,058	57,115
Heat content (Btu/cf, LHV)- assumed	933	933	933	933
Fuel density (lb/ft^3)	0.0448	0.0448	0.0448	0.0448
Fuel usage (cf/hr)- calculated	1,443,832	1,391,103	1,341,054	1,275,357
CT/Bypass and HRSG Stack				
CT/Bypass-Stack height (ft)	80	80	80	80
Diameter (ft)	22	22	22	22
HRSG - Stack Height (ft)	120	120	120	120
Diameter (ft)	19	19	19	19
CT/Bypass Stack Flow Conditions				
Turbine Flow (acfm) = [(Mass Flow (lb/hr) x 1,545 x (Temp. (°F)+ 460°F)] / [Molecular weight x 2116.8] / 60 min/hr				
Mass flow (lb/hr)	2,979,000	2,888,000	2,803,000	2,694,000
Temperature (°F)	1,122	1,139	1,153	1,170
Molecular weight	28.50	28.41	28.33	28.23
Volume flow (acfm)- calculated	2,011,853	1,977,488	1,941,432	1,892,412
(ft^3/s)- calculated	33,531	32,958	32,357	31,540
Diameter (ft)	22.0	22.0	22.0	22.0
Velocity (ft/sec)- calculated	88.2	86.7	85.1	83.0
HRSG Stack Flow Conditions				
Velocity (ft/sec) = Volume flow (acfm) / [((diameter)^2 /4) x 3.14159] / 60 sec/min				
Mass flow (lb/hr)	2,979,000	2,888,000	2,803,000	2,694,000
HRSG Stack Temperature (°F)	187	188	189	190
Molecular weight	28.50	28.41	28.33	28.23
CT volume flow (acfm)	822,545	801,136	781,026	754,411
Diameter (ft)	19	19	19	19
Velocity (ft/sec)- calculated	48.4	47.1	45.9	44.3

Note: Universal gas constant = 1,545 ft-lb(force)/°R; atmospheric pressure = 2,116.8 lb(force)/ft^2; 14.7 lb/ft^3

Source: GE, 2000 - CT Performance Data.

Table A-4. Maximum Emissions for Criteria Pollutants for FPL Martin Unit 8 Combined-Cycle Project
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 75% Load

Parameter	Turbine Inlet Temperature			
	35 °F Case 12	59 °F Case 11	75 °F Case 10	95 °F Case 9
Particulate from CTand SCR				
Total PM_{10} = PM_{10} (front half) + PM_{10} ($(NH_4)_2SO_4$) from SCR only				
a. PM_{10} (front half) (lb/hr)				
CT- provided	9.0	9.0	9.0	9.0
b. PM_{10} ($(NH_4)_2SO_4$) from SCR only = Sulfur trioxide from conversion of SO_2 converts to ammonium sulfate (= PM_{10})				
Particulate from conversion of SO_2 = SO_2 emissions (lb/hr) x conversion of SO_2 to SO_3 x lb SO_3/lb SO_2 x conversion of SO_3 to $(NH_4)_2SO_4$ x lb $(NH_4)_2SO_4$/ lb SO_3				
SO_2 emission rate (lb/hr)- calculated	8.3	7.9	7.7	7.3
Conversion (%) from SO_2 to SO_3	9.8	9.8	9.8	9.8
MW SO_3/ SO_2 (80/64)	1.3	1.3	1.3	1.3
Conversion (%) from SO_3 to $(NH_4)_2(SO_4)$	100	100	100	100
MW $(NH_4)_2$ SO_4/ SO_3 (132/80)	1.7	1.7	1.7	1.7
SCR Particulate (lb/hr)- calculated	1.67	1.61	1.55	1.47
Total CT/Bypass stack emission rate (lb/hr) [a]	9.0	9.0	9.0	9.0
Total HRSG stack emission rate (lb/hr) [a + b]	10.7	10.6	10.5	10.5
(lb/mmBtu, HHV)	0.0068	0.0070	0.0072	0.0075
Sulfur Dioxide				
SO_2 (lb/hr)= Natural gas (scf/hr) x sulfur content(gr/100 scf) x 1 lb/7000 gr x (lb SO_2 /lb S) /100				
Fuel use (cf/hr)	1,443,832	1,391,103	1,341,054	1,275,357
Sulfur content (grains/ 100 cf)	2	2	2	2
lb SO_2 /lb S (64/32)	2	2	2	2
Bypass/HRSG stack emission rate (lb/hr)- calculated	8.3	7.9	7.7	7.3
Nitrogen Oxides				
NOx (lb/hr) = NOx (ppmvd@ 15% O_2) x {[20.9 x (1-Moisture (%)/100] - Oxygen, dry(%)} x 2116.8 lb/ft^2 x Volume flow (acfm) x 46 (mole. wgt NOx) x 60 min/hr / [1545 x (CT temp.(°F) + 460) x (20.9-15) x 1,000,000 (adj. for ppm)]				
CT / DB, ppmvd @15% O_2	9	9	9	9
Moisture (%)	7.49	8.27	8.92	9.8
Oxygen (%)	12.67	12.57	12.49	12.41
Turbine Flow (acfm)	2,011,853	1,977,488	1,941,432	1,892,412
Turbine Exhaust Temperature (°F)	1,122	1,139	1,153	1,170
CT/DB Emission rate (lb/hr)	48.9	47.1	45.4	43.1
CT/Bypasss Stack, ppmvd @ 15% O_2	9	9	9	9
CT/Bypass Stack Emission rate (lb/hr)	48.89	47.09	45.45	43.14
HRSG Stack, ppmvd @ 15% O_2	2.5	2.5	2.5	2.5
HRSG Stack Emission rate (lb/hr)	13.6	13.1	12.6	12.0
Carbon Monoxide				
CO (lb/hr) = CO(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft^2 x Volume flow (acfm) x 28 (mole. wgt CO) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]				
Basis, ppmvd	9	9	9	9
Moisture (%)	7.49	8.27	8.92	9.8
Turbine Flow (acfm)	2,011,853	1,977,488	1,941,432	1,892,412
Turbine Exhaust Temperature (°F)	1,122	1,139	1,153	1,170
HRSG Exhaust Temperature (°F)	187	188	189	190
Bypass/HRSG stack emission rate (lb/hr)- provided	24.4	23.5	22.7	21.7

Table A-4. Maximum Emissions for Criteria Pollutants for FPL Martin Unit 8 Combined-Cycle Project
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 75% Load

Parameter	Turbine Inlet Temperature			
	35 °F Case 12	59 °F Case 11	75 °F Case 10	95 °F Case 9
Volatile Organic Compounds				
VOCs (lb/hr) = VOC(ppmvd) x [1-Moisture(%)/100] x 2116.8 lb/ft^2 x Volume flow (acfm) x 16 (mole. wgt as methane) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]				
Basis, ppmvw	1.5	1.5	1.5	1.5
Moisture (%)	7.49	8.27	8.92	9.8
Turbine Flow (acfm)	2,011,853	1,977,488	1,941,432	1,892,412
Turbine Exhaust Temperature (°F)	1,122	1,139	1,153	1,170
HRSG Exhaust Temperature (°F)	186.8	186.8	186.8	186.8
Bypass/HRSG stack emission rate (lb/hr)- provided	2.32	2.24	2.16	2.07
Sulfuric Acid Mist				
Sulfuric Acid Mist (lb/hr)= SO_2 emission (lb/hr) x Conversion to H_2SO_4 (% by weight)/100				
CT SO_2 emission rate (lb/hr) - provided	8.3	7.9	7.7	7.3
CT Conversion to H_2SO_4 (% by weight) - provided	10	10	10	10
DB SO_2 emission rate (lb/hr) - provided	0	0	0	0
DB Conversion to H_2SO_4 (%) - provided	20	20	20	20
Bypass/HRSG stack emission rate (lb/hr)- calculated	0.83	0.79	0.77	0.73
Lead				
Lead (lb/hr) = NA				
Emission Rate Basis	NA	NA	NA	NA
Emission rate (lb/hr)	NA	NA	NA	NA

Note: ppmvd= parts per million, volume dry; O_2= oxygen.

Source: GE, 2000 - CT Performance Data.

Table A-5. Design Information and Stack Parameters for FPL Martin Unit 8 Combined-Cycle Project
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 50% Load

Parameter	Turbine Inlet Temperature 35 °F Case 16	59 °F Case 15	75 °F Case 14	95 °F Case 13
Combustion Turbine Performance				
Net power output (MW)	91.1	86.5	81.34	74.64
Net heat rate (Btu/kWh, LHV)	11,820	12,050	12,415	12,866
(Btu/kWh, HHV)	13,120	13,375	13,780	14,281
Heat Input (MMBtu/hr, LHV)	1,077	1,042	1,010	960
(MMBtu/hr, HHV)	1,195	1,157	1,121	1,066
Relative Humidity (%)	20	60	60	50
Fuel heating value (Btu/lb, LHV)	20,835	20,835	20,835	20,835
(Btu/lb, HHV)	23,127	23,127	23,127	23,127
(HHV/LHV)	1.110	1.110	1.110	1.110
CT Exhaust Flow				
Mass Flow (lb/hr)- with no margin	2,456,000	2,396,000	2,336,000	2,267,000
- provided	2,456,000	2,396,000	2,336,000	2,267,000
Temperature (°F)	1,168	1,184	1,195	1,200
Moisture (% Vol.)	7.21	7.97	8.62	9.45
Oxygen (% Vol.)	12.99	12.90	12.83	12.80
Molecular Weight	28.51	28.43	28.35	28.25
Fuel Usage				
Fuel usage (lb/hr) = Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu (Fuel Heat Content, Btu/lb (LHV))				
Heat input (MMBtu/hr, LHV)	1,077	1,042	1,010	960
Heat content (Btu/lb, LHV)	20,835	20,835	20,835	20,835
Fuel usage (lb/hr)- calculated	51,682	50,026	48,467	46,091
Heat content (Btu/cf, LHV)- assumed	933	933	933	933
Fuel density (lb/ft^3)	0.0448	0.0448	0.0448	0.0448
Fuel usage (cf/hr)- calculated	1,154,037	1,117,062	1,082,231	1,029,181
CT/Bypass and HRSG Stack				
CT/Bypass-Stack height (ft)	80	80	80	80
Diameter (ft)	22	22	22	22
HRSG - Stack Height (ft)	120	120	120	120
Diameter (ft)	19	19	19	19
CT/Bypass Stack Flow Conditions				
Turbine Flow (acfm) = [(Mass Flow (lb/hr) x 1,545 x (Temp. (°F)+ 460°F)] / [Molecular weight x 2116.8] / 60 min/hr				
Mass flow (lb/hr)	2,456,000	2,396,000	2,336,000	2,267,000
Temperature (°F)	1,168	1,184	1,195	1,200
Molecular weight	28.51	28.43	28.35	28.25
Volume flow (acfm)- calculated	1,705,874	1,685,637	1,658,984	1,620,525
(ft^3/s)- calculated	28,431	28,094	27,650	27,009
Diameter (ft)	22.0	22.0	22.0	22.0
Velocity (ft/sec)- calculated	74.8	73.9	72.7	71.1
HRSG Stack Flow Conditions				
Velocity (ft/sec) = Volume flow (acfm) / [((diameter)^2 /4) x 3.14159] / 60 sec/min				
Mass flow (lb/hr)	2,456,000	2,396,000	2,336,000	2,267,000
HRSG Stack Temperature (°F)	175	178	175	182
Molecular weight	28.51	28.43	28.35	28.25
CT volume flow (acfm)	665,689	653,646	636,829	626,928
Diameter (ft)	19	19	19	19
Velocity (ft/sec)- calculated	39.1	38.4	37.4	36.9

Note: Universal gas constant = 1,545 ft-lb(force)/°R; atmospheric pressure = 2,116.8 lb(force)/ft^2; 14.7 lb/ft^3

Source: GE, 2000 - CT Performance Data.

Table A-6. Maximum Emissions for Criteria Pollutants for FPL Martin Unit 8 Combined-Cycle Project
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 50% Load

Parameter	Turbine Inlet Temperature			
	35 °F Case 16	59 °F Case 15	75 °F Case 14	95 °F Case 13
Particulate from CTand SCR				
Total PM_{10} = PM_{10} (front half) + PM_{10} ($(NH_4)_2SO_4$) from SCR only				
a. PM_{10} (front half) (lb/hr)				
CT- provided	9.0	9.0	9.0	9.0
b. PM_{10} ($(NH_4)_2SO_4$) from SCR only = Sulfur trioxide from conversion of SO_2 converts to ammonium sulfate (= PM_{10})				
Particulate from conversion of SO_2 = SO_2 emissions (lb/hr) x conversion of SO_2 to SO_3 x lb SO_3/lb SO_2 x conversion of SO_3 to $(NH_4)_2SO_4$ x lb $(NH_4)_2SO_4$/ lb SO_3				
SO_2 emission rate (lb/hr)- calculated	6.6	6.4	6.2	5.9
Conversion (%) from SO_2 to SO_3	9.8	9.8	9.8	9.8
MW SO_3/ SO_2 (80/64)	1.3	1.3	1.3	1.3
Conversion (%) from SO_3 to $(NH_4)_2(SO_4)$	100	100	100	100
MW $(NH_4)_2$ SO_4/ SO_3 (132/80)	1.7	1.7	1.7	1.7
SCR Particulate (lb/hr)- calculated	1.33	1.29	1.25	1.19
Total CT/Bypass stack emission rate (lb/hr) [a]	9.0	9.0	9.0	9.0
Total HRSG stack emission rate (lb/hr) [a + b]	10.3	10.3	10.2	10.2
(lb/mmBtu, HHV)	0.0081	0.0083	0.0085	0.0089
Sulfur Dioxide				
SO_2 (lb/hr)= Natural gas (scf/hr) x sulfur content(gr/100 scf) x 1 lb/7000 gr x (lb SO_2 /lb S) /100				
Fuel use (cf/hr)	1,154,037	1,117,062	1,082,231	1,029,181
Sulfur content (grains/ 100 cf)	2	2	2	2
lb SO_2 /lb S (64/32)	2	2	2	2
Bypass/HRSG stack emission rate (lb/hr)- calculated	6.6	6.4	6.2	5.9
Nitrogen Oxides				
NOx (lb/hr) = NOx (ppmvd@ 15% O_2) x {[20.9 x (1-Moisture (%)/100] - Oxygen, dry(%)} x 2116.8 lb/ft^2 x Volume flow (acfm) x 46 (mole. wgt NOx) x 60 min/hr / [1545 x (CT temp.(°F) + 460) x (20.9-15) x 1,000,000 (adj. for ppm)]				
CT / DB, ppmvd @15% O_2	9	9	9	9
Moisture (%)	7.21	7.97	8.62	9.45
Oxygen (%)	12.99	12.90	12.83	12.80
Turbine Flow (acfm)	1,705,874	1,685,637	1,658,984	1,620,525
Turbine Exhaust Temperature (°F)	1,168	1,184	1,195	1,200
CT/DB Emission rate (lb/hr)	38.7	37.5	36.2	34.5
CT/Bypasss Stack, ppmvd @ 15% O_2	9	9	9	9
CT/Bypass Stack Emission rate (lb/hr)	38.70	37.46	36.25	34.49
HRSG Stack, ppmvd @ 15% O_2	2.5	2.5	2.5	2.5
HRSG Stack Emission rate (lb/hr)	10.8	10.4	10.1	9.6
Carbon Monoxide				
CO (lb/hr) = CO(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft^2 x Volume flow (acfm) x 28 (mole. wgt CO) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]				
Basis, ppmvd	9	9	9	9
Moisture (%)	7.21	7.97	8.62	9.45
Turbine Flow (acfm)	1,705,874	1,685,637	1,658,984	1,620,525
Turbine Exhaust Temperature (°F)	1,168	1,184	1,195	1,200
HRSG Exhaust Temperature (°F)	175	178	175	182
Bypass/HRSG stack emission rate (lb/hr)- provided	20.1	19.5	19.0	18.3

Table A-6. Maximum Emissions for Criteria Pollutants for FPL Martin Unit 8 Combined-Cycle Project
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 50% Load

Parameter	Turbine Inlet Temperature			
	35 °F Case 16	59 °F Case 15	75 °F Case 14	95 °F Case 13
Volatile Organic Compounds				
VOCs (lb/hr) = VOC(ppmvd) x [1-Moisture(%)/100] x 2116.8 lb/ft^2 x Volume flow (acfm) x 16 (mole. wgt as methane) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]				
Basis, ppmvw	1.5	1.5	1.5	1.5
Moisture (%)	7.21	7.97	8.62	9.45
Turbine Flow (acfm)	1,705,874	1,685,637	1,658,984	1,620,525
Turbine Exhaust Temperature (°F)	1,168	1,184	1,195	1,200
HRSG Exhaust Temperature (°F)	175	175	175	175
Bypass/HRSG stack emission rate (lb/hr)- provided	1.92	1.86	1.81	1.74
Sulfuric Acid Mist				
Sulfuric Acid Mist (lb/hr)= SO_2 emission (lb/hr) x Conversion to H_2SO_4 (% by weight)/100				
CT SO_2 emission rate (lb/hr) - provided	6.6	6.4	6.2	5.9
CT Conversion to H_2SO_4 (% by weight) - provided	10	10	10	10
DB SO_2 emission rate (lb/hr) - provided	0	0	0	0
DB Conversion to H_2SO_4 (%) - provided	20	20	20	20
Bypass/HRSG stack emission rate (lb/hr)- calculated	0.66	0.64	0.62	0.59
Lead				
Lead (lb/hr) = NA				
Emission Rate Basis	NA	NA	NA	NA
Emission rate (lb/hr)	NA	NA	NA	NA

Note: ppmvd= parts per million, volume dry; O_2= oxygen.

Source: GE, 2000 - CT Performance Data.

Table A-7. Design Information and Stack Parameters for the FPL Martin Unit 8 Combined-Cycle Project
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, Higher Power Modes

Parameter	Turbine Inlet Temperature 35 °F Case 20	59 °F Case 19	75 °F Case 18	95 °F Case 17
Combustion Turbine Performance				
Net power output (MW)	190.3	182.44	174.64	165.54
Net heat rate (Btu/kWh, LHV)	9,080	9,210	9,330	9,482
(Btu/kWh, HHV)	10,079	10,223	10,356	10,525
Heat Input (MMBtu/hr, LHV)	1,728	1,680	1,629	1,570
(MMBtu/hr, HHV)	1,918	1,865	1,809	1,742
Relative Humidity (%)	20	60	60	50
Fuel heating value (Btu/lb, LHV)	20,835	20,835	20,835	20,835
(Btu/lb, HHV)	23,127	23,127	23,127	23,127
(HHV/LHV)	1.110	1.110	1.110	1.110
CT Exhaust Flow				
Mass Flow (lb/hr)- with no margin	3,713,000	3,558,000	3,478,000	3,356,000
- provided	3,713,000	3,558,000	3,478,000	3,356,000
Temperature (°F)	1,109	1,130	1,145	1,158
Moisture (% Vol.)	7.74	8.84	9.61	10.73
Oxygen (% Vol.)	12.39	12.15	12.01	11.81
Molecular Weight	28.48	28.36	28.27	28.15
Fuel Usage				
Fuel usage (lb/hr) = Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu (Fuel Heat Content, Btu/lb (LHV))				
Heat input (MMBtu/hr, LHV)	1,728	1,680	1,629	1,570
Heat content (Btu/lb, LHV)	20,835	20,835	20,835	20,835
Fuel usage (lb/hr)- calculated	82,933	80,648	78,205	75,335
Heat content (Btu/cf, LHV)- assumed	933	933	933	933
Fuel density (lb/ft^3)	0.0448	0.0448	0.0448	0.0448
Fuel usage (cf/hr)- calculated	1,851,839	1,800,825	1,746,274	1,682,185
CT/Bypass and HRSG Stack				
CT/Bypass-Stack height (ft)	80	80	80	80
Diameter (ft)	22	22	22	22
HRSG - Stack Height (ft)	120	120	120	120
Diameter (ft)	19	19	19	19
CT/Bypass Stack Flow Conditions				
Turbine Flow (acfm) = [(Mass Flow (lb/hr) x 1,545 x (Temp. (°F)+ 460°F)] / [Molecular weight x 2116.8] / 60 min/hr				
Mass flow (lb/hr)	3,713,000	3,558,000	3,478,000	3,356,000
Temperature (°F)	1,109	1,130	1,145	1,158
Molecular weight	28.48	28.36	28.27	28.15
Volume flow (acfm)- calculated	2,488,641	2,426,858	2,402,002	2,346,741
(ft^3/s)- calculated	41,477	40,448	40,033	39,112
Diameter (ft)	22	22	22	22
Velocity (ft/sec)- calculated	109.1	106.4	105.3	102.9
HRSG Stack Flow Conditions				
Velocity (ft/sec) = Volume flow (acfm) / [((diameter)^2 /4) x 3.14159] / 60 sec/min				
Mass flow (lb/hr)	3,713,000	3,558,000	3,478,000	3,356,000
HRSG Stack Temperature (°F)	205	205	207	204
Molecular weight	28.48	28.36	28.27	28.15
CT volume flow (acfm)	1,055,240	1,014,759	998,327	962,538
Diameter (ft)	19	19	19	19
Velocity (ft/sec)- calculated	62.0	59.7	58.7	56.6

Note: Universal gas constant = 1,545 ft-lb(force)/°R; atmospheric pressure = 2,116.8 lb(force)/ft^2; 14.7 lb/ft^3

Source: GE, 2000.

Table A-8. Maximum Emissions for Criteria Pollutants for FPL Martin Unit 8 Combined-Cycle Project
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, Higher Power Modes

Parameter	Turbine Inlet Temperature			
	35 °F Case 20	59 °F Case 19	75 °F Case 18	95 °F Case 17
Particulate from CTand SCR				
Total PM_{10} = PM_{10} (front half) + PM_{10} ($(NH_4)_2SO_4$) from SCR only				
a. PM_{10} (front half) (lb/hr)				
CT- provided	9.0	9.0	9.0	9.0
b. PM_{10} ($(NH_4)_2SO_4$) from SCR only = Sulfur trioxide from conversio				
Particulate from conversion of SO_2 = SO_2 emissions (lb/hr) x conversion of SO_2 to SO_3 x lb SO_3/lb SO_2 x conversion of SO_3 to $(NH_4)_2SO_4$ x lb $(NH_4)_2SO_4$/ lb SO_3				
SO_2 emission rate (lb/hr)- calculated	10.6	10.3	10.0	9.6
Conversion (%) from SO_2 to SO_3	9.8	9.8	9.8	9.8
MW SO_3/ SO_2 (80/64)	1.3	1.3	1.3	1.3
Conversion (%) from SO_3 to $(NH_4)_2(SO_4)$	100	100	100	100
MW $(NH_4)_2$ SO_4/ SO_3 (132/80)	1.7	1.7	1.7	1.7
SCR Particulate (lb/hr)- calculated	2.14	2.08	2.02	1.94
Total CT/Bypass stack emission rate (lb/hr) [a]	9.0	9.0	9.0	9.0
Total HRSG stack emission rate (lb/hr) [a + b]	11.1	11.1	11.0	10.9
(lb/mmBtu, HHV)	0.0056	0.0057	0.0058	0.0060
Sulfur Dioxide				
SO_2 (lb/hr)= Natural gas (scf/hr) x sulfur content(gr/100 scf) x 1 lb/7000 gr x (lb SO_2 /lb S) /100				
Fuel use (cf/hr)	1,851,839	1,800,825	1,746,274	1,682,185
Sulfur content (grains/ 100 cf)	2	2	2	2
lb SO_2 /lb S (64/32)	2	2	2	2
Bypass/HRSG stack emission rate (lb/hr)- calculated	10.6	10.3	10.0	9.6
Nitrogen Oxides				
NOx (lb/hr) = NOx (ppmvd@ 15% O_2) x {[20.9 x (1-Moisture (%)/100] - Oxygen, dry(%)} x 2116.8 lb/ft^2 x Volume flow (acfm) x 46 (mole. wgt NOx) x 60 min/hr / [1545 x (CT temp.(°F) + 460) x (20.9-15) x 1,000,000 (adj. for ppm)]				
CT/DB, ppmvd @15% O_2	15	15	15	15
Moisture (%)	7.74	8.84	9.61	10.73
Oxygen (%)	12.39	12.15	12.01	11.81
Turbine Flow (acfm)	2,488,641	2,426,858	2,402,002	2,346,741
Turbine Exhaust Temperature (°F)	1,109	1,130	1,145	1,158
CT/DB Emission rate (lb/hr)	105.1	101.3	99.0	95.5
CT/Bypasss Stack, ppmvd @ 15% O_2	15	15	15	15
CT/Bypass Stack Emission rate (lb/hr)	105.1	101.3	99.0	95.5
HRSG Stack, ppmvd @ 15% O_2	2.5	2.5	2.5	2.5
HRSG Stack Emission rate (lb/hr)	17.5	16.9	16.5	15.9
Carbon Monoxide				
CO (lb/hr) = CO(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft^2 x Volume flow (acfm) x 28 (mole. wgt CO) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]				
Basis, ppmvd	15	15	15	15
Moisture (%)	7.74	8.84	9.61	10.73
Turbine Flow (acfm)	2,488,641	2,426,858	2,402,002	2,346,741
Turbine Exhaust Temperature (°F)	1,109	1,130	1,145	1,158
HRSG Exhaust Temperature (°F)	205	205	207	204
Bypass/HRSG stack emission rate (lb/hr)- provided	50.5	48.0	46.7	44.7

Table A-8. Maximum Emissions for Criteria Pollutants for FPL Martin Unit 8 Combined-Cycle Project
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, Higher Power Modes

Parameter	Turbine Inlet Temperature			
	35 °F Case 20	59 °F Case 19	75 °F Case 18	95 °F Case 17
Volatile Organic Compounds				
VOCs (lb/hr) = VOC(ppmvd) x [1-Moisture(%)/100] x 2116.8 lb/ft^2 x Volume flow (acfm) x 16 (mole. wgt as methane) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]				
Basis, ppmvw	1.5	1.5	1.5	1.5
Moisture (%)	7.74	8.84	9.61	10.73
Turbine Flow (acfm)	2,488,641	2,426,858	2,402,002	2,346,741
Turbine Exhaust Temperature (°F)	1,109	1,130	1,145	1,158
HRSG Exhaust Temperature (°F)	205	205	207	204
Bypass/HRSG stack emission rate (lb/hr)- provided	2.89	2.75	2.67	2.55
Sulfuric Acid Mist				
Sulfuric Acid Mist (lb/hr)= SO_2 emission (lb/hr) x Conversion to H_2SO_4 (% by weight)/100				
CT SO_2 emission rate (lb/hr) - provided	10.6	10.3	10.0	9.6
CT Conversion to H_2SO_4 (% by weight) - provided	10	10	10	10
DB SO_2 emission rate (lb/hr) - provided	0	0	0	0
DB Conversion to H_2SO_4 (%) - provided	20	20	20	20
Bypass/HRSG stack emission rate (lb/hr)- calculated	1.06	1.03	1.00	0.96
Lead				
Lead (lb/hr) = NA				
Emission Rate Basis	NA	NA	NA	NA
Emission rate (lb/hr)	NA	NA	NA	NA

Note: ppmvd= parts per million, volume dry; O_2= oxygen.

Source: GE, 2000 - CT Performance Data.

Table A-9. Design Information and Stack Parameters for FPL Martin Unit 8 Combined-Cycle Project
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, Base Load

Parameter	Turbine Inlet Temperature			
	35 °F Case 28	59 °F Case 26	75 °F Case 24	95 °F Case 22
Combustion Turbine Performance				
Net power output (MW)	189.1	180.4	172.5	172.5
Net heat rate (Btu/kWh, LHV)	10,019	10,037	10,101	9,486
(Btu/kWh, HHV)	10,620	10,639	10,707	10,056
Heat Input (MMBtu/hr, LHV)	1,895	1,811	1,743	1,637
(MMBtu/hr, HHV)	2,008	1,919	1,847	1,735
Relative Humidity (%)	20	60	60	50
Fuel heating value (Btu/lb, LHV)	18,367	18,367	18,367	18,367
(Btu/lb, HHV)	19,469	19,469	19,469	19,469
(HHV/LHV)	1.060	1.060	1.060	1.060
CT Exhaust Flow				
Mass Flow (lb/hr)- with no margin	3,862,000	3,683,000	3,552,000	3,376,000
- provided	3,862,000	3,683,000	3,552,000	3,376,000
Temperature (°F)	1,074	1,098	1,113	1,131
Moisture (% Vol.)	10.6	11.21	11.68	12.18
Oxygen (% Vol.)	11.19	11.06	11.00	11.00
Molecular Weight	28.39	28.33	28.27	28.21
Fuel Usage				
Fuel usage (lb/hr) = Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu (Fuel Heat Content, Btu/lb (LHV))				
Heat input (MMBtu/hr, LHV)	1,895	1,811	1,743	1,637
Heat content (Btu/lb, LHV)	18,367	18,367	18,367	18,367
Fuel usage (lb/hr)- calculated	103,147	98,584	94,871	89,100
CT/Bypass and HRSG Stack				
CT/Bypass-Stack height (ft)	80	80	80	80
Diameter (ft)	22	22	22	22
HRSG - Stack Height (ft)	120	120	120	120
Diameter (ft)	19	19	19	19
CT/Bypass Stack Flow Conditions				
Turbine Flow (acfm) = [(Mass Flow (lb/hr) x 1,545 x (Temp. (°F)+ 460°F)] / [Molecular weight x 2116.8] / 60 min/hr				
Mass flow (lb/hr)	3,862,000	3,683,000	3,552,000	3,376,000
Temperature (°F)	1,074	1,098	1,113	1,131
Molecular weight	28.39	28.33	28.27	28.21
Volume flow (acfm)- calculated	2,538,306	2,464,273	2,403,828	2,316,007
(ft^3/s)- calculated	42,305	41,071	40,064	38,600
Diameter (ft)	22	22	22	22
Velocity (ft/sec)- calculated	111.3	108.0	105.4	101.5
HRSG Stack Flow Conditions				
Velocity (ft/sec) = Volume flow (acfm) / [((diameter)² /4) x 3.14159] / 60 sec/min				
Mass flow (lb/hr)	3,862,000	3,683,000	3,552,000	3,376,000
HRSG Stack Temperature (°F)	297	295	294	294
Molecular weight	28.39	28.33	28.27	28.21
CT volume flow (acfm)	1,252,275	1,193,859	1,151,484	1,096,864
(ft^3/s)- calculated	20,871	19,898	19,191	18,281
Diameter (ft)	19	19	19	19
Velocity (ft/sec)- calculated	73.6	70.2	67.7	64.5

Note: Universal gas constant = 1,545 ft-lb(force)/°R; atmospheric pressure = 2,116.8 lb(force)/ft²; 14.7 lb/ft³

Source: GE, 2000 - CT Performance Data.

Table A-10. Maximum Emissions for Criteria Pollutants for FPL Martin Unit 8 Combined-Cycle Project
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, Base Load

Parameter	Turbine Inlet Temperature			
	35 °F Case 28	59 °F Case 26	75 °F Case 24	95 °F Case 22
Particulate from CTand SCR				
Total PM_{10} = PM_{10} (front half) + PM_{10} ($(NH_4)_2SO_4$) from SCR only				
a. PM_{10} (front half) (lb/hr)				
CT- provided	17.0	17.0	17.0	17.0
b. PM_{10} ($(NH_4)_2SO_4$) from SCR only = Sulfur trioxide from conversion of SO_2 converts to ammonium sulfate (= PM_{10})				
Particulate from conversion of SO_2 = SO_2 emissions (lb/hr) x conversion of SO_2 to SO_3 x lb SO_3/lb SO_2 x conversion of SO_3 to $(NH_4)_2SO_4$ x lb $(NH_4)_2SO_4$/ lb SO_3				
SO_2 emission rate (lb/hr)- calculated	103.1	98.6	94.9	89.1
Conversion (%) from SO_2 to SO_3	9.8	9.8	9.8	9.8
MW SO_3/ SO_2 (80/64)	1.3	1.3	1.3	1.3
Conversion (%) from SO_3 to $(NH_4)_2(SO_4)$	100	100	100	100
MW $(NH_4)_2$ SO_4/ SO_3 (132/80)	1.7	1.7	1.7	1.7
SCR Particulate (lb/hr)- calculated	20.85	19.93	19.18	18.01
Total CT/Bypass stack emission rate (lb/hr) [a]	17.0	17.0	17.0	17.0
Total HRSG stack emission rate (lb/hr) [a + b]	37.8	36.9	36.2	35.0
(lb/mmBtu, HHV)	0.0188	0.0192	0.0196	0.0202
Sulfur Dioxide				
SO_2 (lb/hr)= Fuel oil (lb/hr) x sulfur content(% weight) x (lb SO_2 /lb S) /100				
Fuel oil Sulfur Content	0.05%	0.05%	0.05%	0.05%
Fuel oil use (lb/hr)	103,147	98,584	94,871	89,100
lb SO2 / lb S (64/32)	2	2	2	2
Bypass/HRSG stack emission rate (lb/hr)- calculated	103.1	98.6	94.9	89.1
Nitrogen Oxides				
NOx (lb/hr) = NOx (ppmvd@ 15% O_2) x {[20.9 x (1-Moisture (%)/100] - Oxygen, dry(%)} x 2116.8 lb/ft^2 x Volume flow (acfm) x 46 (mole. wgt NOx) x 60 min/hr / [1545 x (CT temp.(°F) + 460) x (20.9-15) x 1,000,000 (adj. for ppm)]				
CT/DB, ppmvd @15% O_2	42	42	42	42
Moisture (%)	10.6	11.21	11.68	12.18
Oxygen (%)	11.19	11.06	11.00	11.00
Turbine Flow (acfm)	2,538,306	2,464,273	2,403,828	2,316,007
Turbine Exhaust Temperature (°F)	1,074	1,098	1,113	1,131
CT/DB Emission rate (lb/hr)	333.8	319.2	306.8	288.2
CT/Bypasss Stack, ppmvd @ 15% O_2	42	42	42	42
CT/Bypass Stack Emission rate (lb/hr)	333.8	319.2	306.8	288.2
HRSG Stack, ppmvd @ 15% O_2	12	12	12.0	12.0
HRSG Stack Emission rate (lb/hr)	95.4	91.2	87.7	82.3
Carbon Monoxide				
CO (lb/hr) = CO(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft^2 x Volume flow (acfm) x 28 (mole. wgt CO) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]				
Basis, ppmvd	20	20	20	20
Moisture (%)	10.6	11.21	11.68	12.18
Turbine Flow (acfm)	2,538,306	2,464,273	2,403,828	2,316,007
Turbine Exhaust Temperature (°F)	1,074	1,098	1,113	1,131
HRSG Exhaust Temperature (°F)	297	295	294	294
Bypass/HRSG stack emission rate (lb/hr)- provided	68.1	64.7	62.1	58.9

Table A-10. Maximum Emissions for Criteria Pollutants for FPL Martin Unit 8 Combined-Cycle Project
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, Base Load

Parameter	Turbine Inlet Temperature			
	35 °F Case 28	59 °F Case 26	75 °F Case 24	95 °F Case 22
Volatile Organic Compounds				
VOCs (lb/hr) = VOC(ppmvd) x 2116.8 lb/ft^2 x Volume flow (acfm) x 16 (mole. wgt as methane) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]				
Basis, ppmvw	3.5	3.5	3.5	3.5
Moisture (%)	10.60	11.21	11.68	12.18
Turbine Flow (acfm)	11.19	11.06	11.00	11.00
Turbine Exhaust Temperature (°F)	2,538,306	2,464,273	2,403,828	2,316,007
HRSG Exhaust Temperature (°F)	1,074	1,098	1,113	1,131
Bypass/HRSG stack emission rate (lb/hr)- provided	7.62	7.28	7.04	6.70
Sulfuric Acid Mist				
Sulfuric Acid Mist (lb/hr)= SO_2 emission (lb/hr) x Conversion to H_2SO_4 (% by weight)/100				
CT SO_2 emission rate (lb/hr) - provided	103.1	98.6	94.9	89.1
CT Conversion to H_2SO_4 (% by weight) - provided	10	10	10	10
DB SO_2 emission rate (lb/hr) - provided	0	0	0	0
DB Conversion to H_2SO_4 (%) - provided	20	20	20	20
Bypass/HRSG stack emission rate (lb/hr)- calculated	10.31	9.86	9.49	8.91
Lead				
Lead (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Emission Rate Basis (lb/10^{12} Btu)	14	14	14	14
Emission rate (lb/hr)	0.0265	0.0253	0.0244	0.0229

Note: ppmvd= parts per million, volume dry; O_2= oxygen.

Source: GE, 2000 - CT Performance Data.

Table A-11. Design Information and Stack Parameters for FPL Martin Unit 8 Combined-Cycle Project
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, 75% Load

Parameter	Turbine Inlet Temperature 35 °F Case 32	 59 °F Case 31	 75 °F Case 30	 95 °F Case 29
Combustion Turbine Performance				
Net power output (MW)	141.5	135.0	129.1	119.1
Net heat rate (Btu/kWh, LHV)	10,654	10,730	10,866	11,138
(Btu/kWh, HHV)	11,293	11,373	11,518	11,807
Heat Input (MMBtu/hr, LHV)	1,508	1,449	1,403	1,327
(MMBtu/hr, HHV)	1,598	1,536	1,487	1,406
Relative Humidity (%)	20	60	60	50
Fuel heating value (Btu/lb, LHV)	18,387	18,387	18,387	18,387
(Btu/lb, HHV)	19,490	19,490	19,490	19,490
(HHV/LHV)	1.060	1.060	1.060	1.060
CT Exhaust Flow				
Mass Flow (lb/hr)- with no margin	3,024,000	2,936,000	2,871,000	2,758,000
- provided	3,024,000	2,936,000	2,871,000	2,758,000
Temperature (°F)	1,121	1,137	1,149	1,166
Moisture (% Vol.)	10.23	10.68	11.06	11.54
Oxygen (% Vol.)	11.22	11.21	11.22	11.25
Molecular Weight	28.44	28.38	28.33	28.27
Fuel Usage				
Fuel usage (lb/hr) = Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu (Fuel Heat Content, Btu/lb (LHV))				
Heat input (MMBtu/hr, LHV)	1,508	1,449	1,403	1,327
Heat content (Btu/lb, LHV)	18,387	18,387	18,387	18,387
Fuel usage (lb/hr)- calculated	81,993	78,784	76,298	72,154
CT/Bypass and HRSG Stack				
CT/Bypass-Stack height (ft)	80	80	80	80
Diameter (ft)	22	22	22	22
HRSG - Stack Height (ft)	120	120	120	120
Diameter (ft)	19	19	19	19
CT/Bypass Stack Flow Conditions				
Turbine Flow (acfm) = [(Mass Flow (lb/hr) x 1,545 x (Temp. (°F)+ 460°F)] / [Molecular weight x 2116.8] / 60 min/hr				
Mass flow (lb/hr)	3,024,000	2,936,000	2,871,000	2,758,000
Temperature (°F)	1,121	1,137	1,149	1,166
Molecular weight	28.44	28.38	28.33	28.27
Volume flow (acfm)- calculated	2,045,011	2,009,479	1,983,445	1,929,486
(ft^3/s)- calculated	34,084	33,491	33,057	32,158
Diameter (ft)	22	22	22	22
Velocity (ft/sec)- calculated	89.7	88.1	87.0	84.6
HRSG Stack Flow Conditions				
Velocity (ft/sec) = Volume flow (acfm) / [((diameter)² /4) x 3.14159] / 60 sec/min				
Mass flow (lb/hr)	3,024,000	2,936,000	2,871,000	2,758,000
HRSG Stack Temperature (°F)	271	274	276	278
Molecular weight	28.44	28.38	28.33	28.27
CT volume flow (acfm)	945,414	923,329	907,281	875,151
Diameter (ft)	19	19	19	19
Velocity (ft/sec)- calculated	55.6	54.3	53.3	51.4

Note: Universal gas constant = 1,545 ft-lb(force)/°R; atmospheric pressure = 2,116.8 lb(force)/ft²; 14.7 lb/ft³

Source: GE, 2000

Table A-12. Maximum Emissions for Criteria Pollutants for FPL Martin Unit 8 Combined-Cycle Project
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, 75% Load

Parameter	Turbine Inlet Temperature 35 °F Case 32	59 °F Case 31	75 °F Case 30	95 °F Case 29
Particulate from CTand SCR				
Total PM_{10} = PM_{10} (front half) + PM_{10} ($(NH_4)_2SO_4$) from SCR only				
a. PM_{10} (front half) (lb/hr)				
CT- provided	17.0	17.0	17.0	17.0
b. PM_{10} ($(NH_4)_2SO_4$) from SCR only = Sulfur trioxide from conversion of SO_2 converts to ammonium sulfate (= PM_{10})				
Particulate from conversion of SO_2 = SO_2 emissions (lb/hr) x conversion of SO_2 to SO_3 x lb SO_3/lb SO_2 x *conversion of SO_3 to $(NH_4)_2SO_4$ x lb $(NH_4)_2SO_4$/ lb SO_3*				
SO_2 emission rate (lb/hr)- calculated	82.0	78.8	76.3	72.2
Conversion (%) from SO_2 to SO_3	9.8	9.8	9.8	9.8
MW SO_3/ SO_2 (80/64)	1.3	1.3	1.3	1.3
Conversion (%) from SO_3 to $(NH_4)_2(SO_4)$	100	100	100	100
MW $(NH_4)_2$ SO_4/ SO_3 (132/80)	1.7	1.7	1.7	1.7
SCR Particulate (lb/hr)- calculated	16.57	15.92	15.42	14.58
Total CT/Bypass stack emission rate (lb/hr) [a]	17.0	17.0	17.0	17.0
Total HRSG stack emission rate (lb/hr) [a + b]	33.6	32.9	32.4	31.6
(lb/mmBtu, HHV)	0.0208	0.0212	0.0215	0.0222
Sulfur Dioxide				
SO_2 (lb/hr)= Fuel oil (lb/hr) x sulfur content(% weight) x (lb SO_2 /lb S) /100				
Fuel oil Sulfur Content	0.05%	0.05%	0.05%	0.05%
Fuel oil use (lb/hr)	81,993	78,784	76,298	72,154
lb SO2 / lb S (64/32)	2	2	2	2
Bypass/HRSG stack emission rate (lb/hr)- calculated	82.0	78.8	76.3	72.2
Nitrogen Oxides				
NOx (lb/hr) = NOx (ppmvd@ 15% O_2) x {[20.9 x (1-Moisture (%)/100] - Oxygen, dry(%)} x 2116.8 lb/ft^2 x Volume flow (acfm) x 46 (mole. wgt NOx) x 60 min/hr / [1545 x (CT temp.(°F) + 460) x (20.9-15) x 1,000,000 (adj. for ppm)]				
CT/DB, ppmvd @15% O_2	42	42	42	42
Moisture (%)	10.23	10.68	11.06	11.54
Oxygen (%)	11.22	11.21	11.22	11.25
Turbine Flow (acfm)	2,045,011	2,009,479	1,983,445	1,929,486
Turbine Exhaust Temperature (°F)	1,121	1,137	1,149	1,166
CT/DB Emission rate (lb/hr)	262.6	252.6	244.5	231.2
CT/Bypasss Stack, ppmvd @ 15% O_2	42	42	42	42
CT/Bypass Stack Emission rate (lb/hr)	262.6	252.6	244.5	231.2
HRSG Stack, ppmvd @ 15% O_2	12.0	12.0	12.0	12.0
HRSG Stack Emission rate (lb/hr)	75.0	72.2	69.9	66.1
Carbon Monoxide				
CO (lb/hr) = CO(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft^2 x Volume flow (acfm) x 28 (mole. wgt CO) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]				
Basis, ppmvd	20	20	20	20
Moisture (%)	10.23	10.68	11.06	11.54
Turbine Flow (acfm)	2,045,011	2,009,479	1,983,445	1,929,486
Turbine Exhaust Temperature (°F)	1,121	1,137	1,149	1,166
HRSG Exhaust Temperature (°F)	271	274	276	278
Bypass/HRSG stack emission rate (lb/hr)- provided	53.5	51.7	50.5	48.3

Table A-12. Maximum Emissions for Criteria Pollutants for FPL Martin Unit 8 Combined-Cycle Project
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, 75% Load

Parameter	Turbine Inlet Temperature			
	35 °F Case 32	59 °F Case 31	75 °F Case 30	95 °F Case 29
Volatile Organic Compounds				
VOCs (lb/hr) = VOC(ppmvd) x 2116.8 lb/ft^2 x Volume flow (acfm) x 16 (mole. wgt as methane) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]				
Basis, ppmvw	3.5	3.5	3.5	3.5
Moisture (%)	10.23	10.68	11.06	11.54
Turbine Flow (acfm)	11.22	11.21	11.22	11.25
Turbine Exhaust Temperature (°F)	2,045,011	2,009,479	1,983,445	1,929,486
HRSG Exhaust Temperature (°F)	1,121	1,137	1,149	1,166
Bypass/HRSG stack emission rate (lb/hr)- provided	5.95	5.79	5.67	5.46
Sulfuric Acid Mist				
Sulfuric Acid Mist (lb/hr)= SO_2 emission (lb/hr) x Conversion to H_2SO_4 (% by weight)/100				
CT SO_2 emission rate (lb/hr) - provided	82.0	78.8	76.3	72.2
CT Conversion to H_2SO_4 (% by weight) - provided	10	10	10	10
DB SO_2 emission rate (lb/hr) - provided	0	0	0	0
DB Conversion to H_2SO_4 (%) - provided	20	20	20	20
Bypass/HRSG stack emission rate (lb/hr)- calculated	8.20	7.88	7.63	7.22
Lead				
Lead (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Emission Rate Basis (lb/10^{12} Btu)	14	14	14	14
Emission rate (lb/hr)	0.0211	0.0203	0.0196	0.0186

Note: ppmvd= parts per million, volume dry; O2= oxygen.

Source: GE, 2000 - CT Performance Data.

Table A-13. Design Information and Stack Parameters for FPL Martin Unit 8 Combined-Cycle Project
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, 50% Load

Parameter	Turbine Inlet Temperature			
	35 °F Case 36	59 °F Case 35	75 °F Case 34	95 °F Case 33
Combustion Turbine Performance				
Net power output (MW)	93.8	89.5	85.6	78.9
Net heat rate (Btu/kWh, LHV)	12,685	12,867	13,069	13,453
(Btu/kWh, HHV)	13,446	13,639	13,853	14,260
Heat Input (MMBtu/hr, LHV)	1,190	1,152	1,119	1,062
(MMBtu/hr, HHV)	1,261	1,221	1,186	1,125
Relative Humidity (%)	20	60	60	50
Fuel heating value (Btu/lb, LHV)	18,387	18,387	18,387	18,387
(Btu/lb, HHV)	19,490	19,490	19,490	19,490
(HHV/LHV)	1.060	1.060	1.060	1.060
CT Exhaust Flow				
Mass Flow (lb/hr)- with no margin	2,487,000	2,435,000	2,389,000	2,323,000
- provided	2,487,000	2,435,000	2,389,000	2,323,000
Temperature (°F)	1,168	1,182	1,193	1,200
Moisture (% Vol.)	9.29	9.77	10.17	10.6
Oxygen (% Vol.)	11.76	11.76	11.77	11.86
Molecular Weight	28.51	28.46	28.40	28.34
Fuel Usage				
Fuel usage (lb/hr) = Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu (Fuel Heat Content, Btu/lb (LHV))				
Heat input (MMBtu/hr, LHV)	1,190	1,152	1,119	1,062
Heat content (Btu/lb, LHV)	18,387	18,387	18,387	18,387
Fuel usage (lb/hr)- calculated	64,720	62,637	60,847	57,736
CT/Bypass and HRSG Stack				
CT/Bypass-Stack height (ft)	80	80	80	80
Diameter (ft)	22	22	22	22
HRSG - Stack Height (ft)	120	120	120	120
Diameter (ft)	19	19	19	19
Turbine Flow Conditions				
Turbine Flow (acfm) = [(Mass Flow (lb/hr) x 1,545 x (Temp. (°F)+ 460°F)] / [Molecular weight x 2116.8] / 60 min/hr				
Mass flow (lb/hr)	2,487,000	2,435,000	2,389,000	2,323,000
Temperature (°F)	1,168	1,182	1,193	1,200
Molecular weight	28.51	28.46	28.40	28.34
Volume flow (acfm)- calculated	1,727,369	1,709,200	1,691,211	1,654,983
(ft^3/s)- calculated	28,789	28,487	28,187	27,583
Diameter (ft)	22	22	22	22
Velocity (ft/sec)- calculated	75.7	74.9	74.2	72.6
Stack Flow Conditions				
Velocity (ft/sec) = Volume flow (acfm) / [((diameter)² /4) x 3.14159] / 60 sec/min				
Mass flow (lb/hr)	2,487,000	2,435,000	2,389,000	2,323,000
HRSG Stack Temperature (°F)	256	259	264	268
Molecular weight	28.51	28.46	28.40	28.34
CT volume flow (acfm)	759,385	748,426	740,736	725,501
Diameter (ft)	19	19	19	19
Velocity (ft/sec)- calculated	44.6	44.0	43.5	42.6

Note: Universal gas constant = 1,545 ft-lb(force)/°R; atmospheric pressure = 2,116.8 lb(force)/ft²; 14.7 lb/ft³

Source: GE, 2000

Table A-14. Maximum Emissions for Criteria Pollutants for FPL Martin Unit 8 Combined-Cycle Project
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, 50% Load

Parameter	Turbine Inlet Temperature			
	35 °F Case 36	59 °F Case 35	75 °F Case 34	95 °F Case 33
Particulate from CTand SCR				
Total PM_{10} = PM_{10} (front half) + PM_{10} ($(NH_4)_2SO_4$) from SCR only				
a. PM_{10} (front half) (lb/hr)				
CT- provided	17.0	17.0	17.0	17.0
b. PM_{10} ($(NH_4)_2SO_4$) from SCR only = Sulfur trioxide from conversion of SO_2 converts to ammonium sulfate (= PM_{10})				
Particulate from conversion of SO_2 = SO_2 emissions (lb/hr) x conversion of SO_2 to SO_3 x lb SO_3/lb SO_2 x *conversion of SO_3 to $(NH_4)_2SO_4$ x lb $(NH_4)_2SO_4$/ lb SO_3*				
SO_2 emission rate (lb/hr)- calculated	64.7	62.6	60.8	57.7
Conversion (%) from SO_2 to SO_3	9.8	9.8	9.8	9.8
MW SO_3/ SO_2 (80/64)	1.3	1.3	1.3	1.3
Conversion (%) from SO_3 to $(NH_4)_2(SO_4)$	100	100	100	100
MW $(NH_4)_2$ SO_4/ SO_3 (132/80)	1.7	1.7	1.7	1.7
SCR Particulate (lb/hr)- calculated	13.08	12.66	12.30	11.67
Total CT/Bypass stack emission rate (lb/hr) [a]	17.0	17.0	17.0	17.0
Total HRSG stack emission rate (lb/hr) [a + b]	30.1	29.7	29.3	28.7
(lb/mmBtu, HHV)	0.0238	0.0243	0.0247	0.0255
Sulfur Dioxide				
SO_2 (lb/hr)= Fuel oil (lb/hr) x sulfur content(% weight) x (lb SO_2 /lb S) /100				
Fuel oil Sulfur Content	0.05%	0.05%	0.05%	0.05%
Fuel oil use (lb/hr)	64,720	62,637	60,847	57,736
lb SO2 / lb S (64/32)	2	2	2	2
Bypass/HRSG stack emission rate (lb/hr)- calculated	64.7	62.6	60.8	57.7
Nitrogen Oxides				
NOx (lb/hr) = NOx (ppmvd@ 15% O_2) x {[20.9 x (1-Moisture (%)/100] - Oxygen, dry(%)} x 2116.8 lb/ft^2 x Volume flow (acfm) x 46 (mole. wgt NOx) x 60 min/hr / [1545 x (CT temp.(°F) + 460) x (20.9-15) x 1,000,000 (adj. for ppm)]				
CT/DB, ppmvd @15% O_2	42	42	42	42
Moisture (%)	9.29	9.77	10.17	10.6
Oxygen (%)	11.76	11.76	11.77	11.86
Turbine Flow (acfm)	1,727,369	1,709,200	1,691,211	1,654,983
Turbine Exhaust Temperature (°F)	1,168	1,182	1,193	1,200
CT/DB Emission rate (lb/hr)	205.6	198.9	192.9	183.2
CT/Bypasss Stack, ppmvd @ 15% O_2	42	42	42	42
CT/Bypass Stack Emission rate (lb/hr)	205.6	198.9	192.9	183.2
HRSG Stack, ppmvd @ 15% O_2	12	12	12.0	12.0
HRSG Stack Emission rate (lb/hr)	58.7	56.8	55.1	52.3
Carbon Monoxide				
CO (lb/hr) = CO(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft^2 x Volume flow (acfm) x 28 (mole. wgt CO) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]				
Basis, ppmvd	20	20	20	20
Moisture (%)	9.29	9.77	10.17	10.6
Turbine Flow (acfm)	1,727,369	1,709,200	1,691,211	1,654,983
Turbine Exhaust Temperature (°F)	1,168	1,182	1,193	1,200
HRSG Exhaust Temperature (°F)	29	28	28	28
Bypass/HRSG stack emission rate (lb/hr)- provided	44.3	43.2	42.3	41.0

Table A-14. Maximum Emissions for Criteria Pollutants for FPL Martin Unit 8 Combined-Cycle Project
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, 50% Load

Parameter	Turbine Inlet Temperature			
	35 °F Case 36	59 °F Case 35	75 °F Case 34	95 °F Case 33
Volatile Organic Compounds				
VOCs (lb/hr) = VOC(ppmvd) x 2116.8 lb/ft^2 x Volume flow (acfm) x 16 (mole. wgt as methane) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]				
Basis, ppmvw	3.5	3.5	3.5	3.5
Moisture (%)	9.29	9.77	10.17	10.60
Turbine Flow (acfm)	11.76	11.76	11.77	11.86
Turbine Exhaust Temperature (°F)	1,727,369	1,709,200	1,691,211	1,654,983
HRSG Exhaust Temperature (°F)	1,168	1,182	1,193	1,200
Bypass/HRSG stack emission rate (lb/hr)- provided	4.88	4.79	4.71	4.59
Sulfuric Acid Mist				
Sulfuric Acid Mist (lb/hr)= SO_2 emission (lb/hr) x Conversion to H_2SO_4 (% by weight)/100				
CT SO_2 emission rate (lb/hr) - provided	64.7	62.6	60.8	57.7
CT Conversion to H_2SO_4 (% by weight) - provided	10	10	10	10
DB SO_2 emission rate (lb/hr) - provided	0	0	0	0
DB Conversion to H_2SO_4 (%) - provided	20	20	20	20
Bypass/HRSG stack emission rate (lb/hr)- calculated	6.47	6.26	6.08	5.77
Lead				
Lead (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Emission Rate Basis (lb/10^{12} Btu)	14	14	14	14
Emission rate (lb/hr)	0.0167	0.0161	0.0157	0.0149

Note: ppmvd= parts per million, volume dry; O_2= oxygen.

Source: GE, 2000 - CT Performance Data.

Table A-15. Regulated and Hazardous Air Pollutant Emission Factors and Emissions for FPL Martin Unit 8 Combined-Cycle Project when Firing Natural Gas

Parameter		Emission Rate (lb/hr) firing Natural Gas for Operating Conditions of Base Load (1)				Natural Gas Maximum Annual Emissions (TPY) (2)	
Ambient Temperature (°F):		59 °F	59 °F w/DB	80 °F w/DB Power Aug.	59 °F HP Mode	59 °F 1 CT/HRSG	59 °F 4 CTs/HRSGs
HIR (MMBtu/hr):		1,776	2,326	2,273	1,865		
Sulfuric acid mist		0.98	1.59	1.56	1.03	6.9	27.8
HAPs (Section 112(b) of Clean Air Act)							
1,3-Butadiene		0.000764	0.001000	0.000978	0.000802	0.00438	0.0175
Acetaldehyde		0.0711	0.0931	0.0909	0.0746	0.41	1.63
Acrolein		0.0114	0.0149	0.0146	0.0119	0.0652	0.261
Benzene		0.0213	0.0279	0.0273	0.0224	0.122	0.489
Ethylbenzene		0.0568	0.0744	0.0728	0.0597	0.326	1.304
Formadehyde		0.266	0.349	0.341	0.280	1.53	6.11
Naphthalene		0.00231	0.00302	0.00296	0.00242	0.0132	0.0530
Polycyclic Aromatic Hydrocarbons (PAH)	(3)	0.00391	0.00512	0.00500	0.00410	0.0224	0.0897
Propylene Oxide		0.0515	0.0675	0.0659	0.0541	0.295	1.182
Toluene		0.0586	0.0768	0.0750	0.0615	0.336	1.34
Xylene		0.114	0.149	0.146	0.119	0.652	2.61
Antimony		0.0	0.0	0.0	0.0	0.00	0.00
Arsenic		0.0	0.0	0.0	0.0	0.00	0.00
Beryllium		0.0	0.0	0.0	0.0	0.00	0.00
Cadmium		0.0	0.0	0.0	0.0	0.00	0.00
Chromium		0.0	0.0	0.0	0.0	0.00	0.00
Lead		0.0	0.0	0.0	0.0	0.00	0.00
Manganese		0.0	0.0	0.0	0.0	0.00	0.00
Mercury		0.0	0.0	0.0	0.0	0.00	0.00
Nickel		0.0	0.0	0.0	0.0	0.00	0.00
Selenium		0.0	0.0	0.0	0.0	0.00	0.00
HAPs (Total)		0.658	0.862	0.842	0.691	5.03	15.1

(1) Emissions based on the following emission factors and conversion factors for firing natural gas:

Emission Factors		Value	Reference
Sulfuric acid mist		5	%; Conversion of SO_2 to SO_3 in gas turbine
1,3-Butadiene	(a)	0.43	$lb/10^{12}$ Btu; AP-42,Table 3.1-3. EPA 2000
Acetaldehyde		40	$lb/10^{12}$ Btu; AP-42,Table 3.1-3. EPA 2000
Acrolein		6.4	$lb/10^{12}$ Btu; AP-42,Table 3.1-3. EPA 2000
Benzene		12	$lb/10^{12}$ Btu; AP-42,Table 3.1-3. EPA 2000
Ethylbenzene		32	$lb/10^{12}$ Btu; AP-42,Table 3.1-3. EPA 2000
Formadehyde		150	$lb/10^{12}$ Btu; AP-42,Table 3.1-3. EPA 2000. Database
Naphthalene		1.3	$lb/10^{12}$ Btu; AP-42,Table 3.1-3. EPA 2000
Polycyclic Aromatic Hydrocarbons (PAH)		2.2	$lb/10^{12}$ Btu; AP-42,Table 3.1-3. EPA 2000
Propylene Oxide	(a)	29	$lb/10^{12}$ Btu; AP-42,Table 3.1-3. EPA 2000
Toluene		33	$lb/10^{12}$ Btu; AP-42,Table 3.1-3. EPA 2000. Database
Xylene		64	$lb/10^{12}$ Btu; AP-42,Table 3.1-3. EPA 2000
Antimony		0.00E+00	
Arsenic		0.00E+00	
Beryllium		0.00E+00	
Cadmium		0.00E+00	
Chromium		0.00E+00	
Lead		0.00E+00	
Manganese		0.00E+00	
Mercury		0.00E+00	
Nickel		0.00E+00	
Selenium		0.00E+00	

(a) Based on 1/2 the detection limit; expected emissions are lower.

(2) Annual emissions based on ambient temperature of 59 °F firing natural gas for following hours:

0 at base load; CT only
8,760 at base load; CT with duct firing
0 at base load; CT with duct firing and power aug.
0 high power mode; CT only

(3) Assumed to be representative of Polycyclic Organic Matter (POM) emissions, a regulated HAP.

Table A-16. Regulated and Hazardous Air Pollutant Emission Factors and Emissions for FPL FPL Martin Unit 8 Combined-Cycle Project when Firing Distillate Fuel Oil

Parameter		Emission Rate (lb/hr) Firing Distillate Fuel Oil (1)	Maximum Annual Emissions (TPY)			
		Base Load	Distillate Fuel Oil (2)		Natural Gas (4)	Natural Gas and Fuel Oil (5)
Ambient Temperature (°F):		59 °F				
			1	4	4	4
HIR (MMBtu/hr):		1,919	CT/HRSG	CTs/HRSGs	CTs/HRSGs	CTs/HRSGs
Sulfuric acid mist		9.9	2.46	9.9	27.8	36.1
HAPs (Section 112(b) of Clean Air Act)						
1,3-Butadiene		0.0307	0.0077	0.0307	0.0175	0.047
Acetaldehyde		0.00	0.00	0.00	1.63	1.5
Acrolein		0.00	0.00	0.00	0.261	0.25
Benzene		0.106	0.0264	0.1056	0.489	0.57
Ethylbenzene		0.00	0.00	0.00	1.304	1.23
Formadehyde		0.537	0.134	0.537	6.11	6.3
Naphthalene		0.0672	0.0168	0.0672	0.0530	0.117
Polycyclic Aromatic Hydrocarbons (PAH)	(3)	0.0768	0.0192	0.0768	0.0897	0.16
Propylene Oxide		0.00	0.00	0.00	1.182	1.11
Toluene		0.00	0.00	0.00	1.34	1.3
Xylene		0.00	0.00	0.00	2.61	2.5
Antimony		0.00	0.00	0.00	0.00	0.0
Arsenic		0.0211	0.00528	0.0211	0.00	0.021
Beryllium		0.000595	0.000149	0.000595	0.00	0.00059
Cadmium		0.00921	0.00230	0.00921	0.00	0.0092
Chromium		0.0211	0.00528	0.0211	0.00	0.021
Lead		0.0269	0.00672	0.0269	0.00	0.027
Manganese		1.52	0.379	1.52	0.00	1.5
Mercury		0.00230	0.000576	0.00230	0.00	0.0023
Nickel		0.00883	0.00221	0.00883	0.00	0.0088
Selenium		0.0480	0.0120	0.0480	0.00	0.048
HAPs (Total)		2.47	0.824	2.47	15.1	16.7

(1) Emissions based on the following emission factors and conversion factors for firing distillate fuel oil:

Emission Factors		Value	Reference
Sulfuric acid mist		5	%; Conversion of SO_2 to SO_3 in gas turbine
1,3-Butadiene	(a)	16	lb/10^{12} Btu; AP-42,Table 3.1-4. EPA 2000
Acetaldehyde		0.0	
Acrolein		0.0	
Benzene		55	lb/10^{12} Btu; AP-42,Table 3.1-4. EPA 2000
Ethylbenzene		0.0	
Formadehyde		280	lb/10^{12} Btu; AP-42,Table 3.1-4. EPA 2000
Naphthalene		35	lb/10^{12} Btu; AP-42,Table 3.1-4. EPA 2000
Polycyclic Aromatic Hydrocarbons (PAH)		40	lb/10^{12} Btu; AP-42,Table 3.1-4. EPA 2000
Propylene Oxide		0.0	
Toluene		0.0	
Xylene		0.0	
Antimony		0.0	
Arsenic	(a)	11	lb/10^{12} Btu; AP-42,Table 3.1-5. EPA 2000
Beryllium	(a)	0.31	lb/10^{12} Btu; AP-42,Table 3.1-5. EPA 2000
Cadmium		4.8	lb/10^{12} Btu; AP-42,Table 3.1-5. EPA 2000
Chromium		11	lb/10^{12} Btu; AP-42,Table 3.1-5. EPA 2000
Lead		14	lb/10^{12} Btu; AP-42,Table 3.1-5. EPA 2000
Manganese		790	lb/10^{12} Btu; AP-42,Table 3.1-5. EPA 2000
Mercury		1.2	lb/10^{12} Btu; AP-42,Table 3.1-5. EPA 2000
Nickel	(a)	4.6	lb/10^{12} Btu; AP-42,Table 3.1-5. EPA 2000
Selenium	(a)	25	lb/10^{12} Btu; AP-42,Table 3.1-5. EPA 2000

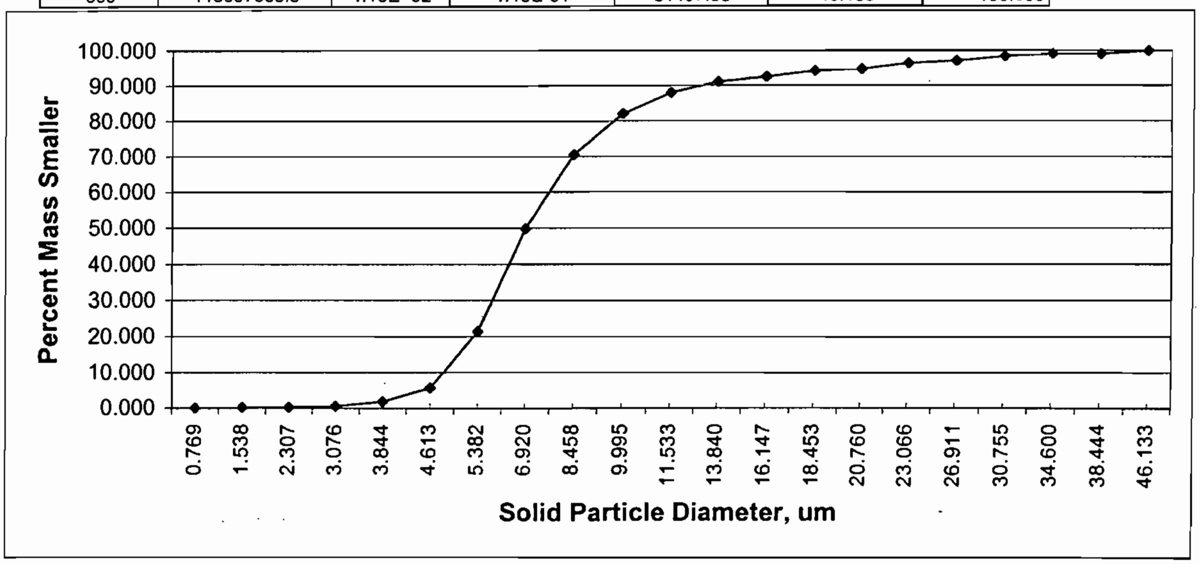
(a) Based on 1/2 the detection limit; expected emissions are lower.

(2) Annual emissions based on ambient temperature of 59 °F and firing fuel oil at base load for : 500 hours
(3) Assumed to be representative of Polycyclic Organic Matter (POM) emissions, a regulated HAP.
(4) Annual emissions based on maximum emissions presented for natural gas-firing
(5) Maximum total annual emissions based on 500 hours of firing fuel and remaining hours firing natural gas.

PM AND PM_{10} EMISSION RATE CALCULATIONS FOR COOLING TOWER

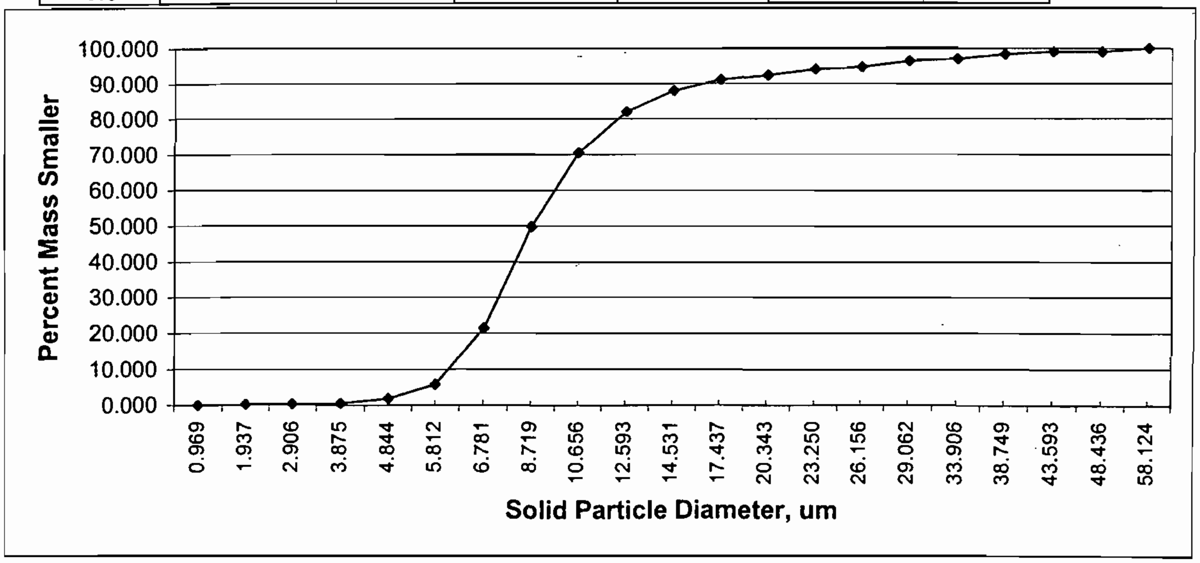
Resultant Solid Particulate Size Destribution (TDS = 1000 ppmw)

EPRI Droplet Diameter (um)	Droplet Volume (um3)	Droplet Mass (ug)	Particulate Mass (Solids) (ug)	Solid Particulate Volume (um3)	Solid Particulate Diameter (um)	EPRI % Mass Smaller
10	523.6	5.24E-04	5.24E-07	0.24	0.769	0.000
20	4188.8	4.19E-03	4.19E-06	1.90	1.538	0.196
30	14137.2	1.41E-02	1.41E-05	6.43	2.307	0.226
40	33510.3	3.35E-02	3.35E-05	15.23	3.076	0.514
50	65449.8	6.54E-02	6.54E-05	29.75	3.844	1.816
60	113097.3	1.13E-01	1.13E-04	51.41	4.613	5.702
70	179594.4	1.80E-01	1.80E-04	81.63	5.382	21.348
90	381703.5	3.82E-01	3.82E-04	173.50	6.920	49.812
110	696910.0	6.97E-01	6.97E-04	316.78	8.458	70.509
130	1150346.5	1.15E+00	1.15E-03	522.88	9.995	82.023
150	1767145.9	1.77E+00	1.77E-03	803.25	11.533	88.012
180	3053628.1	3.05E+00	3.05E-03	1388.01	13.840	91.032
210	4849048.3	4.85E+00	4.85E-03	2204.11	16.147	92.468
240	7238229.5	7.24E+00	7.24E-03	3290.10	18.453	94.091
270	10305994.7	1.03E+01	1.03E-02	4684.54	20.760	94.689
300	14137166.9	1.41E+01	1.41E-02	6425.98	23.066	96.288
350	22449297.5	2.24E+01	2.24E-02	10204.23	26.911	97.011
400	33510321.6	3.35E+01	3.35E-02	15231.96	30.755	98.340
450	47712938.4	4.77E+01	4.77E-02	21687.70	34.600	99.071
500	65449846.9	6.54E+01	6.54E-02	29749.93	38.444	99.071
600	113097335.5	1.13E+02	1.13E-01	51407.88	46.133	100.000



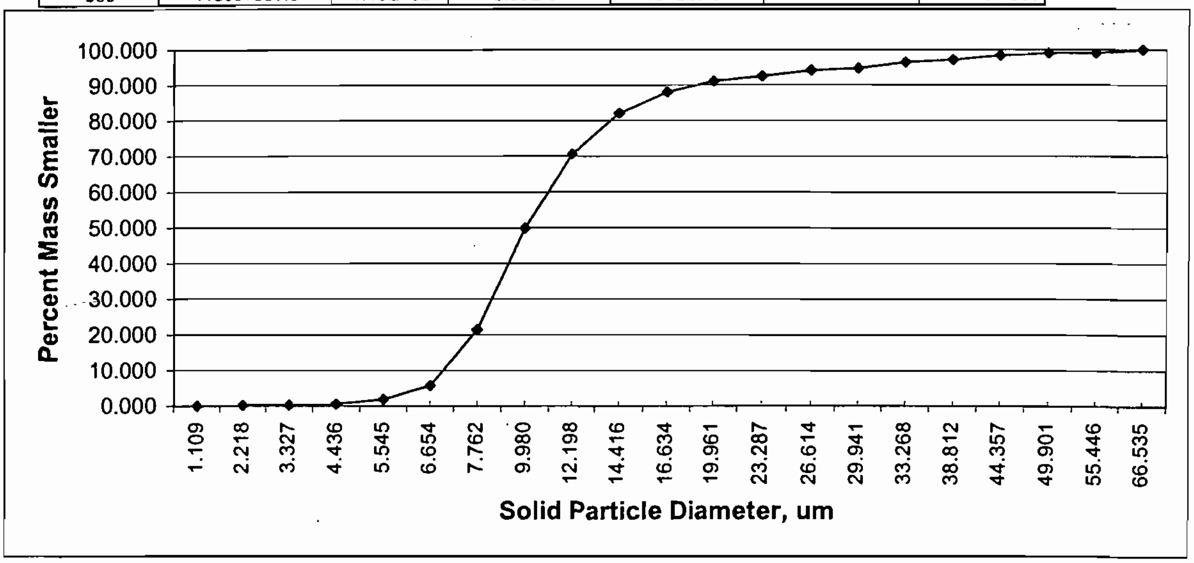
Resultant Solid Particulate Size Destribution (TDS = 2000 ppmw)

EPRI Droplet Diameter (um)	Droplet Volume (um3)	Droplet Mass (ug)	Particulate Mass (Solids) (ug)	Solid Particulate Volume (um3)	Solid Particulate Diameter (um)	EPRI % Mass Smaller
10	523.6	5.24E-04	1.05E-06	0.48	0.969	0.000
20	4188.8	4.19E-03	8.38E-06	3.81	1.937	0.196
30	14137.2	1.41E-02	2.83E-05	12.85	2.906	0.226
40	33510.3	3.35E-02	6.70E-05	30.46	3.875	0.514
50	65449.8	6.54E-02	1.31E-04	59.50	4.844	1.816
60	113097.3	1.13E-01	2.26E-04	102.82	5.812	5.702
70	179594.4	1.80E-01	3.59E-04	163.27	6.781	21.348
90	381703.5	3.82E-01	7.63E-04	347.00	8.719	49.812
110	696910.0	6.97E-01	1.39E-03	633.55	10.656	70.509
130	1150346.5	1.15E+00	2.30E-03	1045.77	12.593	82.023
150	1767145.9	1.77E+00	3.53E-03	1606.50	14.531	88.012
180	3053628.1	3.05E+00	6.11E-03	2776.03	17.437	91.032
210	4849048.3	4.85E+00	9.70E-03	4408.23	20.343	92.468
240	7238229.5	7.24E+00	1.45E-02	6580.21	23.250	94.091
270	10305994.7	1.03E+01	2.06E-02	9369.09	26.156	94.689
300	14137166.9	1.41E+01	2.83E-02	12851.97	29.062	96.288
350	22449297.5	2.24E+01	4.49E-02	20408.45	33.906	97.011
400	33510321.6	3.35E+01	6.70E-02	30463.93	38.749	98.340
450	47712938.4	4.77E+01	9.54E-02	43375.40	43.593	99.071
500	65449846.9	6.54E+01	1.31E-01	59499.86	48.436	99.071
600	113097335.5	1.13E+02	2.26E-01	102815.76	58.124	100.000



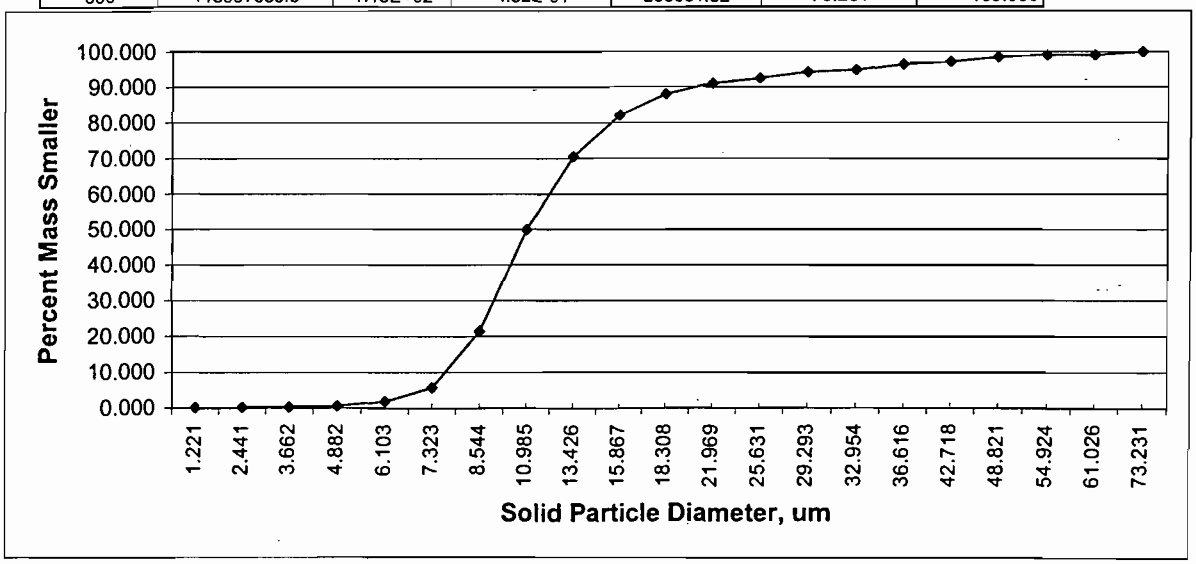
Resultant Solid Particulate Size Destribution (TDS = 3000 ppmw)

EPRI Droplet Diameter (um)	Droplet Volume (um3)	Droplet Mass (ug)	Particulate Mass (Solids) (ug)	Solid Particulate Volume (um3)	Solid Particulate Diameter (um)	EPRI % Mass Smaller
10	523.6	5.24E-04	1.57E-06	0.71	1.109	0.000
20	4188.8	4.19E-03	1.26E-05	5.71	2.218	0.196
30	14137.2	1.41E-02	4.24E-05	19.28	3.327	0.226
40	33510.3	3.35E-02	1.01E-04	45.70	4.436	0.514
50	65449.8	6.54E-02	1.96E-04	89.25	5.545	1.816
60	113097.3	1.13E-01	3.39E-04	154.22	6.654	5.702
70	179594.4	1.80E-01	5.39E-04	244.90	7.762	21.348
90	381703.5	3.82E-01	1.15E-03	520.50	9.980	49.812
110	696910.0	6.97E-01	2.09E-03	950.33	12.198	70.509
130	1150346.5	1.15E+00	3.45E-03	1568.65	14.416	82.023
150	1767145.9	1.77E+00	5.30E-03	2409.74	16.634	88.012
180	3053628.1	3.05E+00	9.16E-03	4164.04	19.961	91.032
210	4849048.3	4.85E+00	1.45E-02	6612.34	23.287	92.468
240	7238229.5	7.24E+00	2.17E-02	9870.31	26.614	94.091
270	10305994.7	1.03E+01	3.09E-02	14053.63	29.941	94.689
300	14137166.9	1.41E+01	4.24E-02	19277.95	33.268	96.288
350	22449297.5	2.24E+01	6.73E-02	30612.68	38.812	97.011
400	33510321.6	3.35E+01	1.01E-01	45695.89	44.357	98.340
450	47712938.4	4.77E+01	1.43E-01	65063.10	49.901	99.071
500	65449846.9	6.54E+01	1.96E-01	89249.79	55.446	99.071
600	113097335.5	1.13E+02	3.39E-01	154223.64	66.535	100.000



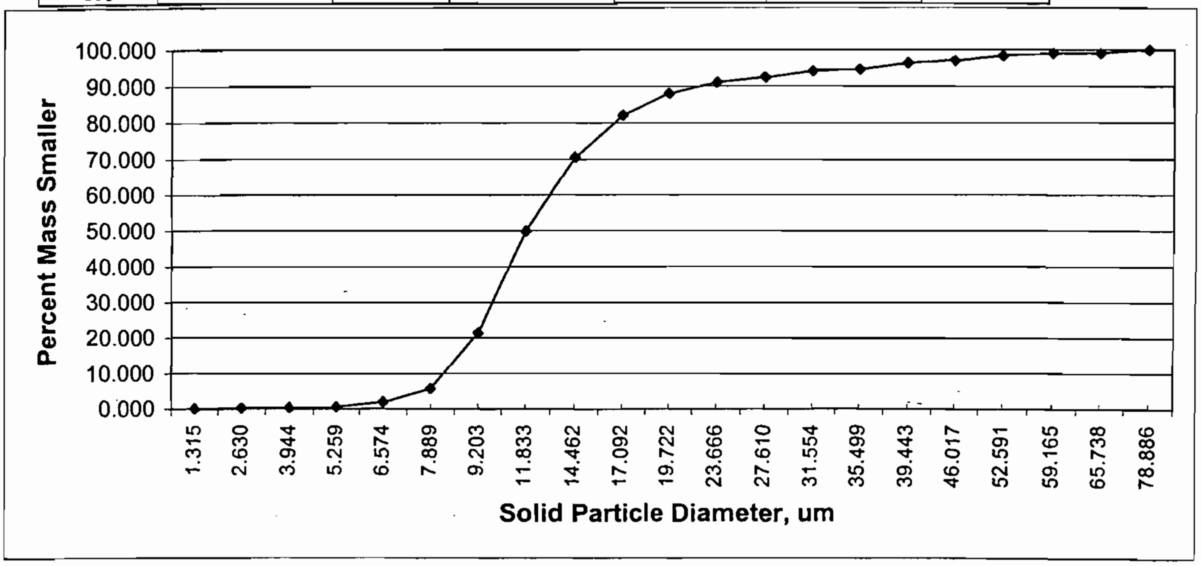
Resultant Solid Particulate Size Destribution (TDS = 4000 ppmw)

EPRI Droplet Diameter (um)	Droplet Volume (um3)	Droplet Mass (ug)	Particulate Mass (Solids) (ug)	Solid Particulate Volume (um3)	Solid Particulate Diameter (um)	EPRI % Mass Smaller
10	523.6	5.24E-04	2.09E-06	0.95	1.221	0.000
20	4188.8	4.19E-03	1.68E-05	7.62	2.441	0.196
30	14137.2	1.41E-02	5.65E-05	25.70	3.662	0.226
40	33510.3	3.35E-02	1.34E-04	60.93	4.882	0.514
50	65449.8	6.54E-02	2.62E-04	119.00	6.103	1.816
60	113097.3	1.13E-01	4.52E-04	205.63	7.323	5.702
70	179594.4	1.80E-01	7.18E-04	326.54	8.544	21.348
90	381703.5	3.82E-01	1.53E-03	694.01	10.985	49.812
110	696910.0	6.97E-01	2.79E-03	1267.11	13.426	70.509
130	1150346.5	1.15E+00	4.60E-03	2091.54	15.867	82.023
150	1767145.9	1.77E+00	7.07E-03	3212.99	18.308	88.012
180	3053628.1	3.05E+00	1.22E-02	5552.05	21.969	91.032
210	4849048.3	4.85E+00	1.94E-02	8816.45	25.631	92.468
240	7238229.5	7.24E+00	2.90E-02	13160.42	29.293	94.091
270	10305994.7	1.03E+01	4.12E-02	18738.17	32.954	94.689
300	14137166.9	1.41E+01	5.65E-02	25703.94	36.616	96.288
350	22449297.5	2.24E+01	8.98E-02	40816.90	42.718	97.011
400	33510321.6	3.35E+01	1.34E-01	60927.86	48.821	98.340
450	47712938.4	4.77E+01	1.91E-01	86750.80	54.924	99.071
500	65449846.9	6.54E+01	2.62E-01	118999.72	61.026	99.071
600	113097335.5	1.13E+02	4.52E-01	205631.52	73.231	100.000



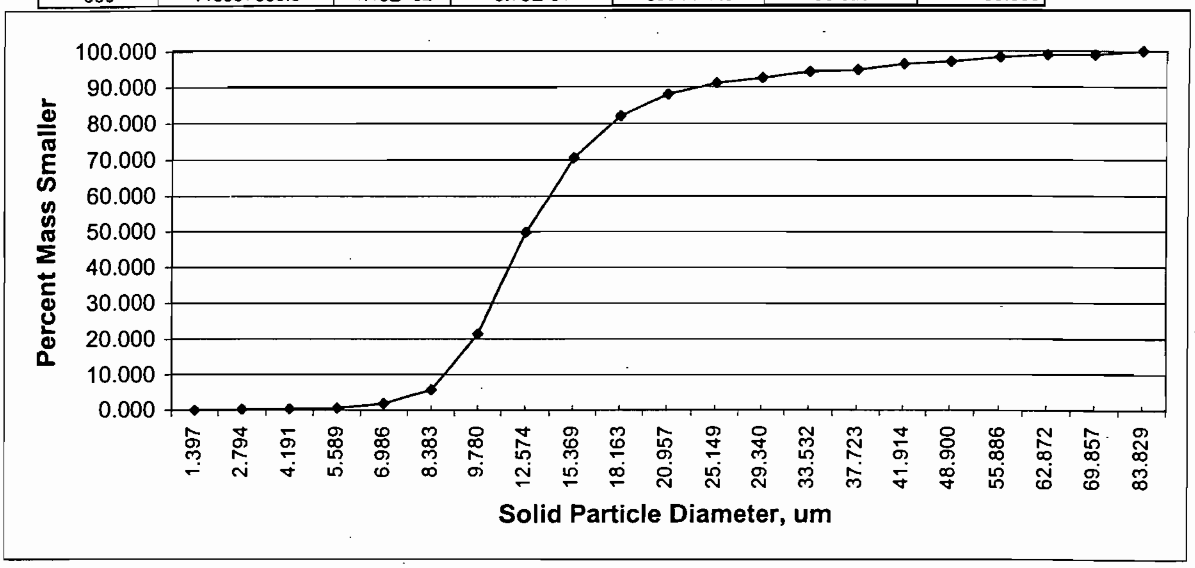
Resultant Solid Particulate Size Destribution (TDS = 5000 ppmw)

EPRI Droplet Diameter (um)	Droplet Volume (um3)	Droplet Mass (ug)	Particulate Mass (Solids) (ug)	Solid Particulate Volume (um3)	Solid Particulate Diameter (um)	EPRI % Mass Smaller
10	523.6	5.24E-04	2.62E-06	1.19	1.315	0.000
20	4188.8	4.19E-03	2.09E-05	9.52	2.630	0.196
30	14137.2	1.41E-02	7.07E-05	32.13	3.944	0.226
40	33510.3	3.35E-02	1.68E-04	76.16	5.259	0.514
50	65449.8	6.54E-02	3.27E-04	148.75	6.574	1.816
60	113097.3	1.13E-01	5.65E-04	257.04	7.889	5.702
70	179594.4	1.80E-01	8.98E-04	408.17	9.203	21.348
90	381703.5	3.82E-01	1.91E-03	867.51	11.833	49.812
110	696910.0	6.97E-01	3.48E-03	1583.89	14.462	70.509
130	1150346.5	1.15E+00	5.75E-03	2614.42	17.092	82.023
150	1767145.9	1.77E+00	8.84E-03	4016.24	19.722	88.012
180	3053628.1	3.05E+00	1.53E-02	6940.06	23.666	91.032
210	4849048.3	4.85E+00	2.42E-02	11020.56	27.610	92.468
240	7238229.5	7.24E+00	3.62E-02	16450.52	31.554	94.091
270	10305994.7	1.03E+01	5.15E-02	23422.72	35.499	94.689
300	14137166.9	1.41E+01	7.07E-02	32129.92	39.443	96.288
350	22449297.5	2.24E+01	1.12E-01	51021.13	46.017	97.011
400	33510321.6	3.35E+01	1.68E-01	76159.82	52.591	98.340
450	47712938.4	4.77E+01	2.39E-01	108438.50	59.165	99.071
500	65449846.9	6.54E+01	3.27E-01	148749.65	65.738	99.071
600	113097335.5	1.13E+02	5.65E-01	257039.40	78.886	100.000



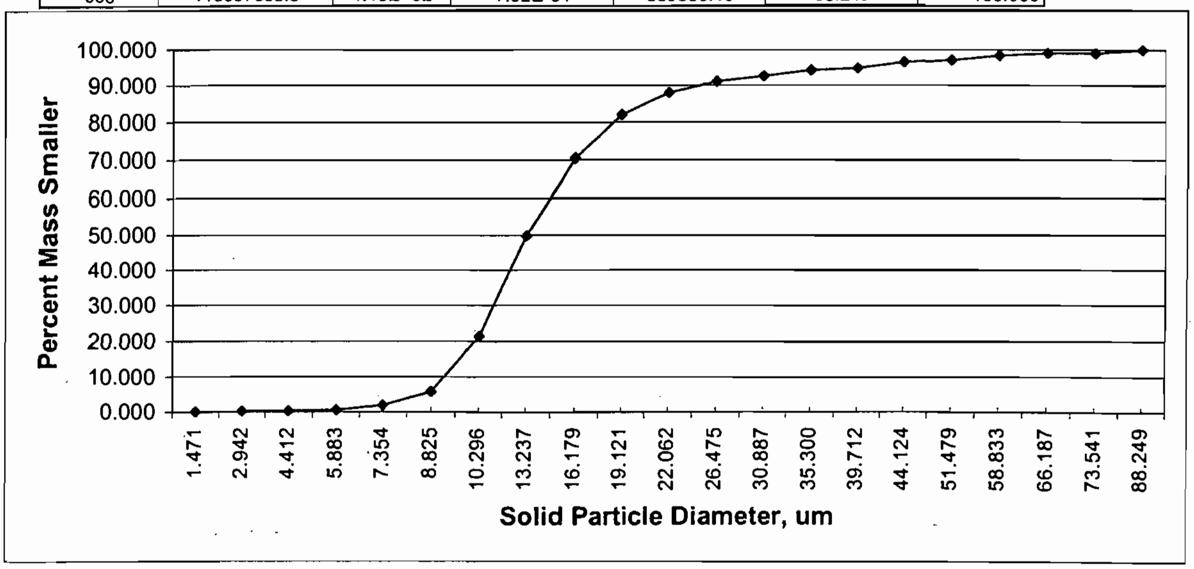
Resultant Solid Particulate Size Destribution (TDS = 6000 ppmw)

EPRI Droplet Diameter (um)	Droplet Volume (um3)	Droplet Mass (ug)	Particulate Mass (Solids) (ug)	Solid Particulate Volume (um3)	Solid Particulate Diameter (um)	EPRI % Mass Smaller
10	523.6	5.24E-04	3.14E-06	1.43	1.397	0.000
20	4188.8	4.19E-03	2.51E-05	11.42	2.794	0.196
30	14137.2	1.41E-02	8.48E-05	38.56	4.191	0.226
40	33510.3	3.35E-02	2.01E-04	91.39	5.589	0.514
50	65449.8	6.54E-02	3.93E-04	178.50	6.986	1.816
60	113097.3	1.13E-01	6.79E-04	308.45	8.383	5.702
70	179594.4	1.80E-01	1.08E-03	489.80	9.780	21.348
90	381703.5	3.82E-01	2.29E-03	1041.01	12.574	49.812
110	696910.0	6.97E-01	4.18E-03	1900.66	15.369	70.509
130	1150346.5	1.15E+00	6.90E-03	3137.31	18.163	82.023
150	1767145.9	1.77E+00	1.06E-02	4819.49	20.957	88.012
180	3053628.1	3.05E+00	1.83E-02	8328.08	25.149	91.032
210	4849048.3	4.85E+00	2.91E-02	13224.68	29.340	92.468
240	7238229.5	7.24E+00	4.34E-02	19740.63	33.532	94.091
270	10305994.7	1.03E+01	6.18E-02	28107.26	37.723	94.689
300	14137166.9	1.41E+01	8.48E-02	38555.91	41.914	96.288
350	22449297.5	2.24E+01	1.35E-01	61225.36	48.900	97.011
400	33510321.6	3.35E+01	2.01E-01	91391.79	55.886	98.340
450	47712938.4	4.77E+01	2.86E-01	130126.20	62.872	99.071
500	65449846.9	6.54E+01	3.93E-01	178499.58	69.857	99.071
600	113097335.5	1.13E+02	6.79E-01	308447.28	83.829	100.000



Resultant Solid Particulate Size Destribution (TDS = 7000 ppmw)

EPRI Droplet Diameter (um)	Droplet Volume (um3)	Droplet Mass (ug)	Particulate Mass (Solids) (ug)	Solid Particulate Volume (um3)	Solid Particulate Diameter (um)	EPRI % Mass Smaller
10	523.6	5.24E-04	3.67E-06	1.67	1.471	0.000
20	4188.8	4.19E-03	2.93E-05	13.33	2.942	0.196
30	14137.2	1.41E-02	9.90E-05	44.98	4.412	0.226
40	33510.3	3.35E-02	2.35E-04	106.62	5.883	0.514
50	65449.8	6.54E-02	4.58E-04	208.25	7.354	1.816
60	113097.3	1.13E-01	7.92E-04	359.86	8.825	5.702
70	179594.4	1.80E-01	1.26E-03	571.44	10.296	21.348
90	381703.5	3.82E-01	2.67E-03	1214.51	13.237	49.812
110	696910.0	6.97E-01	4.88E-03	2217.44	16.179	70.509
130	1150346.5	1.15E+00	8.05E-03	3660.19	19.121	82.023
150	1767145.9	1.77E+00	1.24E-02	5622.74	22.062	88.012
180	3053628.1	3.05E+00	2.14E-02	9716.09	26.475	91.032
210	4849048.3	4.85E+00	3.39E-02	15428.79	30.887	92.468
240	7238229.5	7.24E+00	5.07E-02	23030.73	35.300	94.091
270	10305994.7	1.03E+01	7.21E-02	32791.80	39.712	94.689
300	14137166.9	1.41E+01	9.90E-02	44981.89	44.124	96.288
350	22449297.5	2.24E+01	1.57E-01	71429.58	51.479	97.011
400	33510321.6	3.35E+01	2.35E-01	106623.75	58.833	98.340
450	47712938.4	4.77E+01	3.34E-01	151813.89	66.187	99.071
500	65449846.9	6.54E+01	4.58E-01	208249.51	73.541	99.071
600	113097335.5	1.13E+02	7.92E-01	359855.16	88.249	100.000

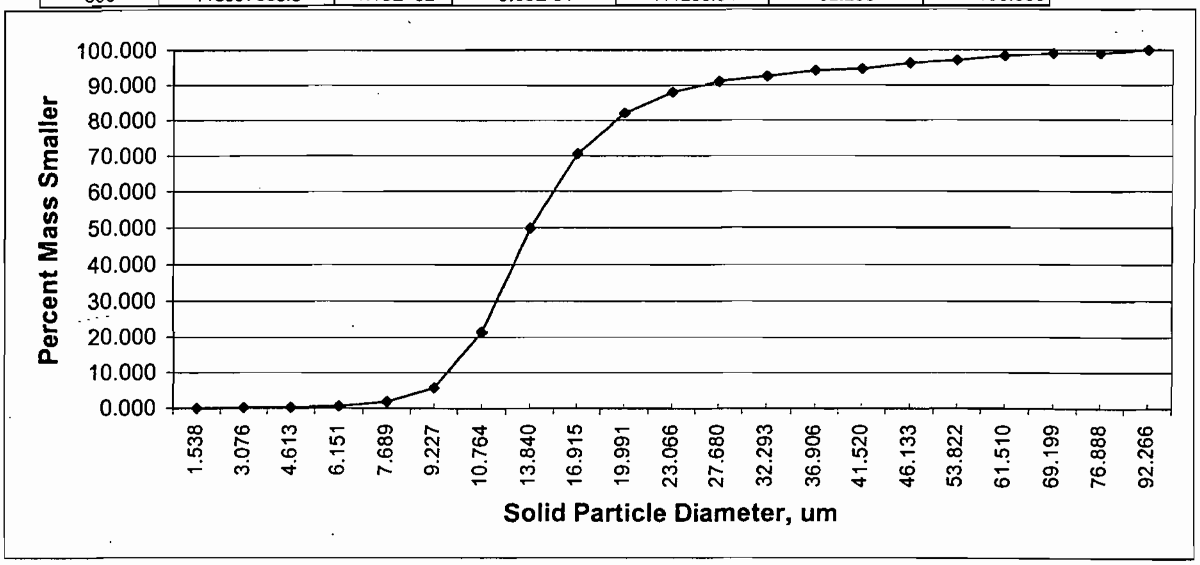


Resultant Solid Particulate Size Destribution (TDS = 9000 ppmw)

EPRI Droplet Diameter (um)	Droplet Volume (um3)	Droplet Mass (ug)	Particulate Mass (Solids) (ug)	Solid Particulate Volume (um3)	Solid Particulate Diameter (um)	EPRI % Mass Smaller
10	523.6	5.24E-04	4.03E-06	1.83	1.518	0.000
20	4188.8	4.19E-03	3.23E-05	14.66	3.037	0.196
30	14137.2	1.41E-02	1.09E-04	49.48	4.555	0.226
40	33510.3	3.35E-02	2.58E-04	117.29	6.073	0.514
50	65449.8	6.54E-02	5.04E-04	229.07	7.591	1.816
60	113097.3	1.13E-01	8.71E-04	395.84	9.110	5.702
70	179594.4	1.80E-01	1.38E-03	628.58	10.628	21.348
90	381703.5	3.82E-01	2.94E-03	1335.96	13.665	49.812
110	696910.0	6.97E-01	5.37E-03	2439.18	16.701	70.509
130	1150346.5	1.15E+00	8.86E-03	4026.21	19.738	82.023
150	1767145.9	1.77E+00	1.36E-02	6185.01	22.774	88.012
180	3053628.1	3.05E+00	2.35E-02	10687.70	27.329	91.032
210	4849048.3	4.85E+00	3.73E-02	16971.67	31.884	92.468
240	7238229.5	7.24E+00	5.57E-02	25333.80	36.439	94.091
270	10305994.7	1.03E+01	7.94E-02	36070.98	40.994	94.689
300	14137166.9	1.41E+01	1.09E-01	49480.08	45.549	96.288
350	22449297.5	2.24E+01	1.73E-01	78572.54	53.140	97.011
400	33510321.6	3.35E+01	2.58E-01	117286.13	60.732	98.340
450	47712938.4	4.77E+01	3.67E-01	166995.28	68.323	99.071
500	65449846.9	6.54E+01	5.04E-01	229074.46	75.915	99.071
600	113097335.5	1.13E+02	8.71E-01	395840.67	91.098	100.000

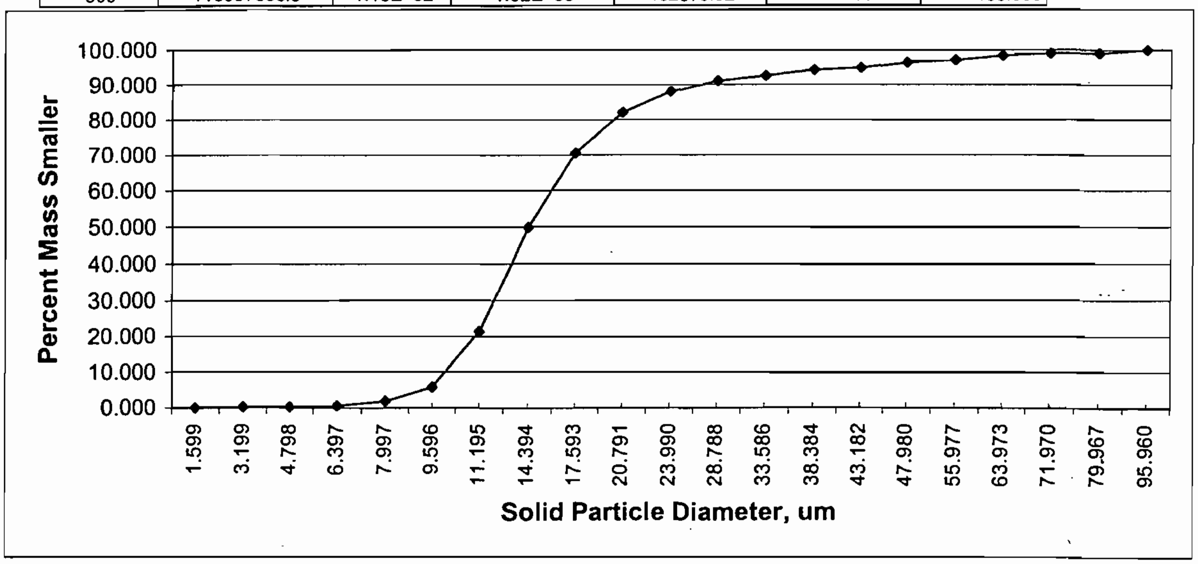
Resultant Solid Particulate Size Destribution (TDS = 8000 ppmw)

EPRI Droplet Diameter (um)	Droplet Volume (um3)	Droplet Mass (ug)	Particulate Mass (Solids) (ug)	Solid Particulate Volume (um3)	Solid Particulate Diameter (um)	EPRI % Mass Smaller
10	523.6	5.24E-04	4.19E-06	1.90	1.538	0.000
20	4188.8	4.19E-03	3.35E-05	15.23	3.076	0.196
30	14137.2	1.41E-02	1.13E-04	51.41	4.613	0.226
40	33510.3	3.35E-02	2.68E-04	121.86	6.151	0.514
50	65449.8	6.54E-02	5.24E-04	238.00	7.689	1.816
60	113097.3	1.13E-01	9.05E-04	411.26	9.227	5.702
70	179594.4	1.80E-01	1.44E-03	653.07	10.764	21.348
90	381703.5	3.82E-01	3.05E-03	1388.01	13.840	49.812
110	696910.0	6.97E-01	5.58E-03	2534.22	16.915	70.509
130	1150346.5	1.15E+00	9.20E-03	4183.08	19.991	82.023
150	1767145.9	1.77E+00	1.41E-02	6425.98	23.066	88.012
180	3053628.1	3.05E+00	2.44E-02	11104.10	27.680	91.032
210	4849048.3	4.85E+00	3.88E-02	17632.90	32.293	92.468
240	7238229.5	7.24E+00	5.79E-02	26320.83	36.906	94.091
270	10305994.7	1.03E+01	8.24E-02	37476.34	41.520	94.689
300	14137166.9	1.41E+01	1.13E-01	51407.88	46.133	96.288
350	22449297.5	2.24E+01	1.80E-01	81633.81	53.822	97.011
400	33510321.6	3.35E+01	2.68E-01	121855.72	61.510	98.340
450	47712938.4	4.77E+01	3.82E-01	173501.59	69.199	99.071
500	65449846.9	6.54E+01	5.24E-01	237999.44	76.888	99.071
600	113097335.5	1.13E+02	9.05E-01	411263.04	92.266	100.000



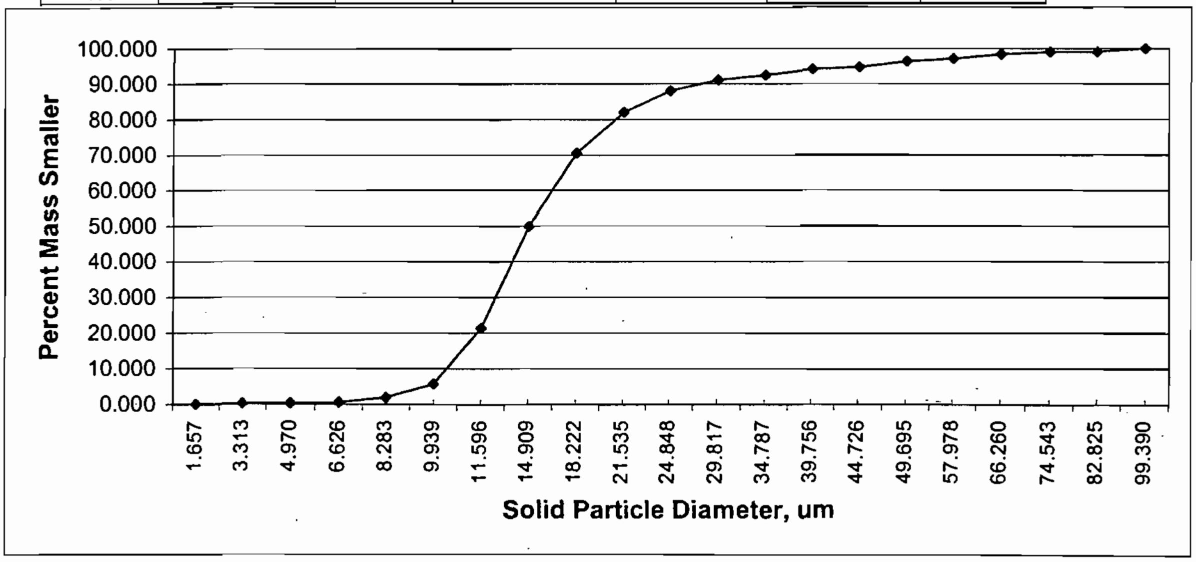
Resultant Solid Particulate Size Destribution (TDS = 9000 ppmw)

EPRI Droplet Diameter (um)	Droplet Volume (um3)	Droplet Mass (ug)	Particulate Mass (Solids) (ug)	Solid Particulate Volume (um3)	Solid Particulate Diameter (um)	EPRI % Mass Smaller
10	523.6	5.24E-04	4.71E-06	2.14	1.599	0.000
20	4188.8	4.19E-03	3.77E-05	17.14	3.199	0.196
30	14137.2	1.41E-02	1.27E-04	57.83	4.798	0.226
40	33510.3	3.35E-02	3.02E-04	137.09	6.397	0.514
50	65449.8	6.54E-02	5.89E-04	267.75	7.997	1.816
60	113097.3	1.13E-01	1.02E-03	462.67	9.596	5.702
70	179594.4	1.80E-01	1.62E-03	734.70	11.195	21.348
90	381703.5	3.82E-01	3.44E-03	1561.51	14.394	49.812
110	696910.0	6.97E-01	6.27E-03	2851.00	17.593	70.509
130	1150346.5	1.15E+00	1.04E-02	4705.96	20.791	82.023
150	1767145.9	1.77E+00	1.59E-02	7229.23	23.990	88.012
180	3053628.1	3.05E+00	2.75E-02	12492.11	28.788	91.032
210	4849048.3	4.85E+00	4.36E-02	19837.02	33.586	92.468
240	7238229.5	7.24E+00	6.51E-02	29610.94	38.384	94.091
270	10305994.7	1.03E+01	9.28E-02	42160.89	43.182	94.689
300	14137166.9	1.41E+01	1.27E-01	57833.86	47.980	96.288
350	22449297.5	2.24E+01	2.02E-01	91838.04	55.977	97.011
400	33510321.6	3.35E+01	3.02E-01	137087.68	63.973	98.340
450	47712938.4	4.77E+01	4.29E-01	195189.29	71.970	99.071
500	65449846.9	6.54E+01	5.89E-01	267749.37	79.967	99.071
600	113097335.5	1.13E+02	1.02E+00	462670.92	95.960	100.000



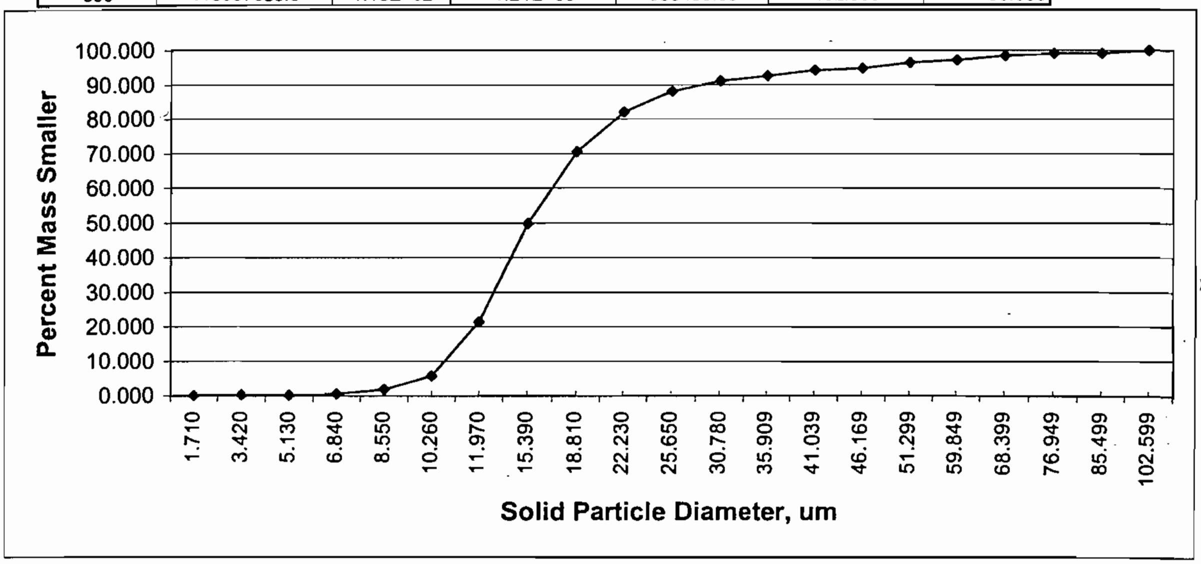
Resultant Solid Particulate Size Destribution (TDS = 10000 ppmw)

EPRI Droplet Diameter (um)	Droplet Volume (um3)	Droplet Mass (ug)	Particulate Mass (Solids) (ug)	Solid Particulate Volume (um3)	Solid Particulate Diameter (um)	EPRI % Mass Smaller
10	523.6	5.24E-04	5.24E-06	2.38	1.657	0.000
20	4188.8	4.19E-03	4.19E-05	19.04	3.313	0.196
30	14137.2	1.41E-02	1.41E-04	64.26	4.970	0.226
40	33510.3	3.35E-02	3.35E-04	152.32	6.626	0.514
50	65449.8	6.54E-02	6.54E-04	297.50	8.283	1.816
60	113097.3	1.13E-01	1.13E-03	514.08	9.939	5.702
70	179594.4	1.80E-01	1.80E-03	816.34	11.596	21.348
90	381703.5	3.82E-01	3.82E-03	1735.02	14.909	49.812
110	696910.0	6.97E-01	6.97E-03	3167.77	18.222	70.509
130	1150346.5	1.15E+00	1.15E-02	5228.85	21.535	82.023
150	1767145.9	1.77E+00	1.77E-02	8032.48	24.848	88.012
180	3053628.1	3.05E+00	3.05E-02	13880.13	29.817	91.032
210	4849048.3	4.85E+00	4.85E-02	22041.13	34.787	92.468
240	7238229.5	7.24E+00	7.24E-02	32901.04	39.756	94.091
270	10305994.7	1.03E+01	1.03E-01	46845.43	44.726	94.689
300	14137166.9	1.41E+01	1.41E-01	64259.85	49.695	96.288
350	22449297.5	2.24E+01	2.24E-01	102042.26	57.978	97.011
400	33510321.6	3.35E+01	3.35E-01	152319.64	66.260	98.340
450	47712938.4	4.77E+01	4.77E-01	216876.99	74.543	99.071
500	65449846.9	6.54E+01	6.54E-01	297499.30	82.825	99.071
600	113097335.5	1.13E+02	1.13E+00	514078.80	99.390	100.000



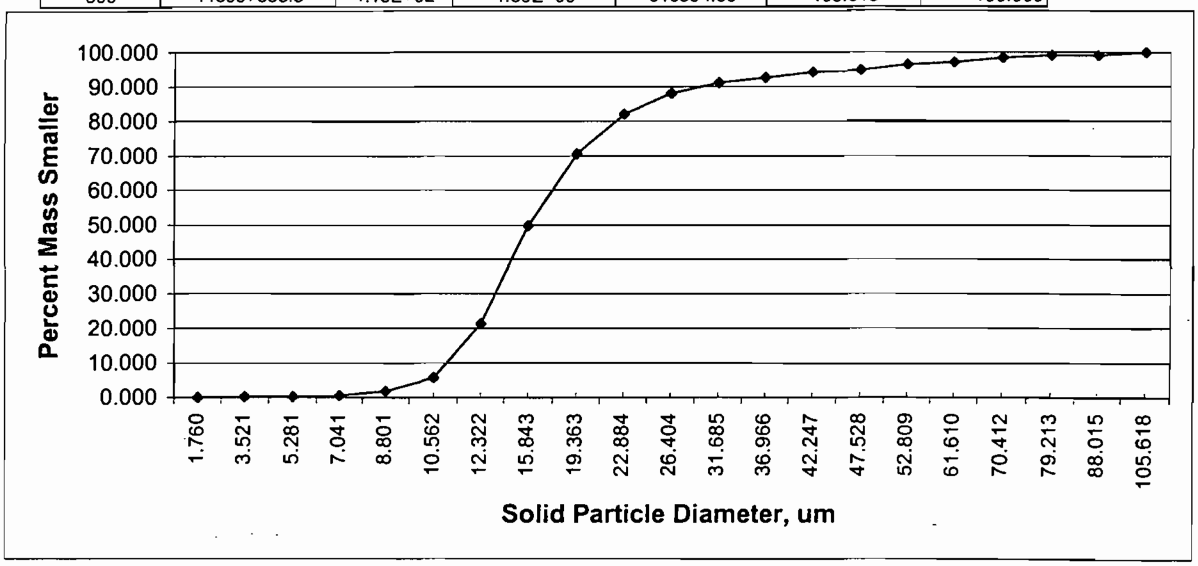
Resultant Solid Particulate Size Destribution (TDS = 11000 ppmw)

EPRI Droplet Diameter (um)	Droplet Volume (um3)	Droplet Mass (ug)	Particulate Mass (Solids) (ug)	Solid Particulate Volume (um3)	Solid Particulate Diameter (um)	EPRI % Mass Smaller
10	523.6	5.24E-04	5.76E-06	2.62	1.710	0.000
20	4188.8	4.19E-03	4.61E-05	20.94	3.420	0.196
30	14137.2	1.41E-02	1.56E-04	70.69	5.130	0.226
40	33510.3	3.35E-02	3.69E-04	167.55	6.840	0.514
50	65449.8	6.54E-02	7.20E-04	327.25	8.550	1.816
60	113097.3	1.13E-01	1.24E-03	565.49	10.260	5.702
70	179594.4	1.80E-01	1.98E-03	897.97	11.970	21.348
90	381703.5	3.82E-01	4.20E-03	1908.52	15.390	49.812
110	696910.0	6.97E-01	7.67E-03	3484.55	18.810	70.509
130	1150346.5	1.15E+00	1.27E-02	5751.73	22.230	82.023
150	1767145.9	1.77E+00	1.94E-02	8835.73	25.650	88.012
180	3053628.1	3.05E+00	3.36E-02	15268.14	30.780	91.032
210	4849048.3	4.85E+00	5.33E-02	24245.24	35.909	92.468
240	7238229.5	7.24E+00	7.96E-02	36191.15	41.039	94.091
270	10305994.7	1.03E+01	1.13E-01	51529.97	46.169	94.689
300	14137166.9	1.41E+01	1.56E-01	70685.83	51.299	96.288
350	22449297.5	2.24E+01	2.47E-01	112246.49	59.849	97.011
400	33510321.6	3.35E+01	3.69E-01	167551.61	68.399	98.340
450	47712938.4	4.77E+01	5.25E-01	238564.69	76.949	99.071
500	65449846.9	6.54E+01	7.20E-01	327249.23	85.499	99.071
600	113097335.5	1.13E+02	1.24E+00	565486.68	102.599	100.000



Resultant Solid Particulate Size Destribution (TDS = 12000 ppmw)

EPRI Droplet Diameter (um)	Droplet Volume (um3)	Droplet Mass (ug)	Particulate Mass (Solids) (ug)	Solid Particulate Volume (um3)	Solid Particulate Diameter (um)	EPRI % Mass Smaller
10	523.6	5.24E-04	6.28E-06	2.86	1.760	0.000
20	4188.8	4.19E-03	5.03E-05	22.85	3.521	0.196
30	14137.2	1.41E-02	1.70E-04	77.11	5.281	0.226
40	33510.3	3.35E-02	4.02E-04	182.78	7.041	0.514
50	65449.8	6.54E-02	7.85E-04	357.00	8.801	1.816
60	113097.3	1.13E-01	1.36E-03	616.89	10.562	5.702
70	179594.4	1.80E-01	2.16E-03	979.61	12.322	21.348
90	381703.5	3.82E-01	4.58E-03	2082.02	15.843	49.812
110	696910.0	6.97E-01	8.36E-03	3801.33	19.363	70.509
130	1150346.5	1.15E+00	1.38E-02	6274.62	22.884	82.023
150	1767145.9	1.77E+00	2.12E-02	9638.98	26.404	88.012
180	3053628.1	3.05E+00	3.66E-02	16656.15	31.685	91.032
210	4849048.3	4.85E+00	5.82E-02	26449.35	36.966	92.468
240	7238229.5	7.24E+00	8.69E-02	39481.25	42.247	94.091
270	10305994.7	1.03E+01	1.24E-01	56214.52	47.528	94.689
300	14137166.9	1.41E+01	1.70E-01	77111.82	52.809	96.288
350	22449297.5	2.24E+01	2.69E-01	122450.71	61.610	97.011
400	33510321.6	3.35E+01	4.02E-01	182783.57	70.412	98.340
450	47712938.4	4.77E+01	5.73E-01	260252.39	79.213	99.071
500	65449846.9	6.54E+01	7.85E-01	356999.17	88.015	99.071
600	113097335.5	1.13E+02	1.36E+00	616894.56	105.618	100.000



Calculating Realistic PM_{10} Emissions from Cooling Towers

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ABSTRACT

Particulate matter less than 10 micrometers in diameter (PM_{10}) emissions from wet cooling towers may be calculated using the methodology presented in EPA's AP-42[1] , which assumes that all total dissolved solids (TDS) emitted in "drift" particles (liquid water entrained in the air stream and carried out of the tower through the induced draft fan stack.) are PM_{10}. However, for wet cooling towers with medium to high TDS levels, this method is overly conservative, and predicts significantly higher PM_{10} emissions than would actually occur, even for towers equipped with very high efficiency drift eliminators (e.g., 0.0006% drift rate). Such over-prediction may result in unrealistically high PM_{10} modeled concentrations and/or the need to purchase expensive Emission Reduction Credits (ERCs) in PM_{10} non-attainment areas. Since these towers have fairly low emission points (10 to 15 m above ground), over-predicting PM_{10} emission rates can easily result in exceeding federal Prevention of Significant Deterioration (PSD) significance levels at a project's fenceline. This paper presents a method for computing realistic PM_{10} emissions from cooling towers with medium to high TDS levels.

INTRODUCTION

Cooling towers are heat exchangers that are used to dissipate large heat loads to the atmosphere. Wet, or evaporative, cooling towers rely on the latent heat of water evaporation to exchange heat between the process and the air passing through the cooling tower. The cooling water may be an integral part of the process or may provide cooling via heat exchangers, for example, steam condensers. Wet cooling towers provide direct contact between the cooling water and air passing through the tower, and as part of normal operation, a very small amount of the circulating water may be entrained in the air stream and be carried out of the tower as "drift" droplets. Because the drift droplets contain the same chemical impurities as the water circulating through the tower, the particulate matter constituent of the drift droplets may be classified as an emission. The magnitude of the drift loss is influenced by the number and size of droplets produced within the tower, which are determined by the tower fill design, tower design, the air and water patterns, and design of the drift eliminators.

AP-42 METHOD OF CALCULATING DRIFT PARTICULATE

EPA's AP-42[1] provides available particulate emission factors for wet cooling towers, however, these values only have an emission factor rating of "E" (the lowest level of confidence acceptable). They are also rather high, compared to typical present-day manufacturers' guaranteed drift rates, which are on the order of 0.0006%. (Drift emissions are typically expressed as a percentage of the cooling tower water circulation rate). AP-42 states that "a *conservatively high* PM_{10} emission factor can be obtained by (a) multiplying the total liquid drift factor by the TDS fraction in the circulating water, and (b) assuming that once the water evaporates, all remaining solid particles are within the PM_{10} range." (Italics per EPA).

If TDS data for the cooling tower are not available, a source-specific TDS content can be estimated by obtaining the TDS for the make-up water and multiplying it by the cooling tower cycles of concentration. [The cycles of concentration is the ratio of a measured parameter for the cooling tower water (such as conductivity, calcium, chlorides, or phosphate) to that parameter for the make-up water.]

Using AP-42 guidance, the total particulate emissions (PM) (after the pure water has evaporated) can be expressed as:

$$\text{PM} = \text{Water Circulation Rate x Drift Rate x TDS} \qquad [1]$$

For example, for a typical power plant wet cooling tower with a water circulation rate of 146,000 gallons per minute (gpm), drift rate of 0.0006%, and TDS of 7,700 parts per million by weight (ppmw):

$$\text{PM} = 146{,}000 \text{ gpm x } 8.34 \text{ lb water/gal x } 0.0006/100 \text{ x } 7{,}700 \text{ lb solids}/10^6 \text{ lb water x } 60 \text{ min/hr} = \underline{3.38 \text{ lb/hr}}$$

On an annual basis, this is equivalent to almost 15 tons per year (tpy). Even for a state-of-the-art drift eliminator system, this is not a small number, especially if assumed to all be equal to PM_{10}, a regulated criteria pollutant. However, as the following analysis demonstrates, only a very small fraction is actually PM_{10}.

COMPUTING THE PM_{10} FRACTION

Based on a representative drift droplet size distribution and TDS in the water, the amount of solid mass in each drop size can be calculated. That is, for a given initial droplet size, assuming that the mass of dissolved solids condenses to a spherical particle after all the water evaporates, and assuming the density of the TDS is equivalent to a representative salt (e.g., sodium chloride), the diameter of the final solid particle can be calculated. Thus, using the drift droplet size distribution, the percentage of drift mass containing particles small enough to produce PM_{10} can be calculated. This method is conservative as the final particle is assumed to be perfectly spherical; hence as small a particle as can exist.

The droplet size distribution of the drift emitted from the tower is critical to performing the analysis. Brentwood Industries, a drift eliminator manufacturer, was contacted and agreed to provide drift eliminator test data from a test conducted by Environmental Systems Corporation (ESC) at the Electric Power Research Institute (EPRI) test facility in Houston, Texas in 1988 (Aull[2], 1999). The data consist of water droplet size distributions for a drift eliminator that achieved a tested drift rate of 0.0003 percent. As we are using a 0.0006 percent drift rate, it is reasonable to expect that the 0.0003 percent drift rate would produce smaller droplets, therefore, this size distribution data can be assumed to be conservative for predicting the fraction of PM_{10} in the total cooling tower PM emissions.

In calculating PM_{10} emissions the following assumptions were made:

- Each water droplet was assumed to evaporate shortly after being emitted into ambient air, into a single, solid, spherical particle.
- Drift water droplets have a density (ρ_w) of water; 1.0 g/cm^3 or $1.0 * 10^{-6}\ \mu g / \mu m^3$.
- The solid particles were assumed to have the same density (ρ_{TDS}) as sodium chloride, (i.e., 2.2 g/cm^3).

Using the formula for the volume of a sphere, $V = 4\pi r^3/3$, and the density of pure water, $\rho_w = 1.0$ g/cm^3, the following equations can be used to derive the solid particulate diameter, D_p, as a function of the TDS, the density of the solids, and the initial drift droplet diameter, D_d :

$$\text{Volume of drift droplet} = (4/3)\pi(D_d/2)^3 \qquad [2]$$

$$\text{Mass of solids in drift droplet} = (TDS)(\rho_w)(\text{Volume of drift droplet}) \qquad [3]$$

substituting,

$$\text{Mass of solids in drift} = (TDS)(\rho_w)(4/3)\pi(D_d/2)^3 \qquad [4]$$

Assuming the solids remain and coalesce after the water evaporates, the mass of solids can also be expressed as:

$$\text{Mass of solids} = (\rho_{TDS})\ (\text{solid particle volume}) = (\rho_{TDS})(4/3)\pi(D_p/2)^3 \qquad [5]$$

Equations [4] and [5] are equivalent:

$$(\rho_{TDS})(4/3)\pi(D_p/2)^3 = (TDS)(\rho_w)(4/3)\pi(D_d/2)^3 \qquad [6]$$

Solving for D_p:

$$D_p = D_d\ [(TDS)(\rho_w / \rho_{TDS})]^{1/3} \qquad [7]$$

Where,

TDS is in units of ppmw
D_p = diameter of solid particle, micrometers (μm)
D_d = diameter of drift droplet, μm

Using formulas [2] – [7] and the particle size distribution test data, Table 1 can be constructed for drift from a wet cooling tower having the same characteristics as our example; 7,700 ppmw TDS and a 0.0006% drift rate. The first and last columns of this table are the particle size distribution derived from test results provided by Brentwood Industries. Using straight-line interpolation for a solid particle size 10 μm in diameter, we conclude that approximately 14.9 percent of the mass emissions are equal to or smaller than PM_{10}. The balance of the solid particulate are particulate greater than 10 μm. Hence, PM_{10} emissions from this tower would be equal to PM emissions x 0.149, or 3.38 lb/hr x 0.149 = 0.50 lb/hr. The process is repeated in Table 2, with all parameters equal except that the TDS is 11,000 ppmw. The result is that approximately 5.11 percent are smaller at 11,000 ppm. Thus, while total PM emissions are larger by virtue of a higher TDS, overall PM_{10} emissions are actually lower, because more of the solid particles are larger than 10 μm.

Table 1. Resultant Solid Particulate Size Distribution (TDS = 7700 ppmw)

EPRI Droplet Diameter (μm)	Droplet Volume (μm^3) [2][1]	Droplet Mass (μg) [3]	Particle Mass (Solids) (μg) [4]	Solid Particle Volume (μm^3)	Solid Particle Diameter (μm) [7]	EPRI % Mass Smaller
10	524	5.24E-04	4.03E-06	1.83	1.518	0.000
20	4189	4.19E-03	3.23E-05	14.66	3.037	0.196
30	14137	1.41E-02	1.09E-04	49.48	4.555	0.226
40	33510	3.35E-02	2.58E-04	117.29	6.073	0.514
50	65450	6.54E-02	5.04E-04	229.07	7.591	1.816
60	113097	1.13E-01	8.71E-04	395.84	9.110	5.702
70	179594	1.80E-01	1.38E-03	628.58	10.628	21.348
90	381704	3.82E-01	2.94E-03	1335.96	13.665	49.812
110	696910	6.97E-01	5.37E-03	2439.18	16.701	70.509
130	1150347	1.15E+00	8.86E-03	4026.21	19.738	82.023
150	1767146	1.77E+00	1.36E-02	6185.01	22.774	88.012
180	3053628	3.05E+00	2.35E-02	10687.70	27.329	91.032
210	4849048	4.85E+00	3.73E-02	16971.67	31.884	92.468
240	7238229	7.24E+00	5.57E-02	25333.80	36.439	94.091
270	10305995	1.03E+01	7.94E-02	36070.98	40.994	94.689
300	14137167	1.41E+01	1.09E-01	49480.08	45.549	96.288
350	22449298	2.24E+01	1.73E-01	78572.54	53.140	97.011
400	33510322	3.35E+01	2.58E-01	117286.13	60.732	98.340
450	47712938	4.77E+01	3.67E-01	166995.28	68.323	99.071
500	65449847	6.54E+01	5.04E-01	229074.46	75.915	99.071
600	113097336	1.13E+02	8.71E-01	395840.67	91.098	100.000

[1] *Bracketed numbers refer to equation number in text.*

The percentage of PM_{10}/PM was calculated for cooling tower TDS values from 1000 to 12000 ppmw and the results are plotted in Figure 1. Using these data, Figure 2 presents predicted PM_{10} emission rates for the 146,000 gpm example tower. As shown in this figure, the PM emission rate increases in a straight line as TDS increases, however, the PM_{10} emission rate increases to a maximum at around a TDS of 4000 ppmw, and then begins to decline. The reason is that at higher TDS, the drift droplets contain more solids and therefore, upon evaporation, result in larger solid particles for any given initial droplet size.

CONCLUSION

The emission factors and methodology given in EPA's AP-42[1] Chapter 13.4 *Wet Cooling Towers*, do not account for the droplet size distribution of the drift exiting the tower. This is a critical factor, as more than 85% of the mass of particulate in the drift from most cooling towers will result in solid particles larger than PM_{10} once the water has evaporated. Particles larger than PM_{10} are no longer a regulated air pollutant, because their impact on human health has been shown to be insignificant. Using reasonable, conservative assumptions and a realistic drift droplet size distribution, a method is now available for calculating realistic PM_{10} emission rates from wet mechanical draft cooling towers equipped with modern, high-efficiency drift eliminators and operating at medium to high levels of TDS in the circulating water.

Table 2. Resultant Solid Particulate Size Distribution (TDS = 11000 ppmw)

EPRI Droplet Diameter (μm)	Droplet Volume (μm^3) [2][1]	Droplet Mass (μg) [3]	Particle Mass (Solids) (μg) [4]	Solid Particle Volume (μm^3)	Solid Particle Diameter (μm) [7]	EPRI % Mass Smaller
10	524	5.24E-04	5.76E-06	2.62	1.710	0.000
20	4189	4.19E-03	4.61E-05	20.94	3.420	0.196
30	14137	1.41E-02	1.56E-04	70.69	5.130	0.226
40	33510	3.35E-02	3.69E-04	167.55	6.840	0.514
50	65450	6.54E-02	7.20E-04	327.25	8.550	1.816
60	113097	1.13E-01	1.24E-03	565.49	10.260	5.702
70	179594	1.80E-01	1.98E-03	897.97	11.970	21.348
90	381704	3.82E-01	4.20E-03	1908.52	15.390	49.812
110	696910	6.97E-01	7.67E-03	3484.55	18.810	70.509
130	1150347	1.15E+00	1.27E-02	5751.73	22.230	82.023
150	1767146	1.77E+00	1.94E-02	8835.73	25.650	88.012
180	3053628	3.05E+00	3.36E-02	15268.14	30.780	91.032
210	4849048	4.85E+00	5.33E-02	24245.24	35.909	92.468
240	7238229	7.24E+00	7.96E-02	36191.15	41.039	94.091
270	10305995	1.03E+01	1.13E-01	51529.97	46.169	94.689
300	14137167	1.41E+01	1.56E-01	70685.83	51.299	96.288
350	22449298	2.24E+01	2.47E-01	112246.49	59.849	97.011
400	33510322	3.35E+01	3.69E-01	167551.61	68.399	98.340
450	47712938	4.77E+01	5.25E-01	238564.69	76.949	99.071
500	65449847	6.54E+01	7.20E-01	327249.23	85.499	99.071
600	113097336	1.13E+02	1.24E+00	565486.68	102.599	100.000

Figure 1: Percentage of Drift PM that Evaporates to PM10

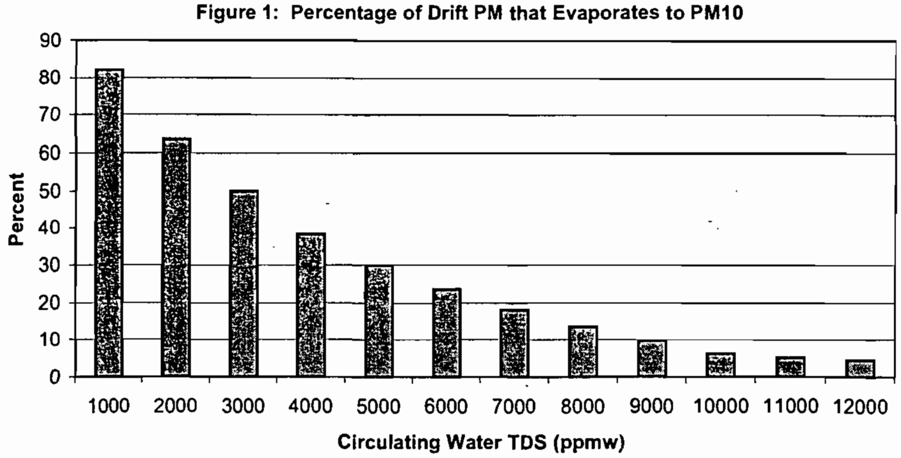
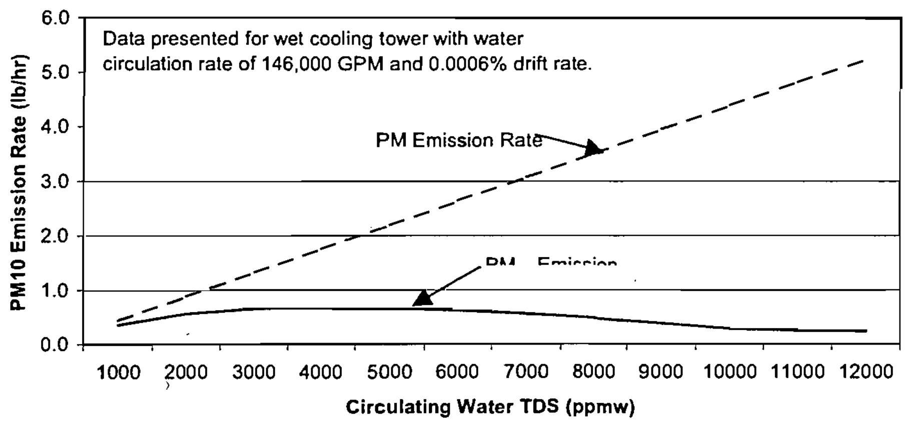


Figure 2: PM_{10} Emission Rate vs. TDS



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2. Aull, 1999. Memorandum from R. Aull, Brentwood Industries to J. Reisman, Greystone, December 7, 1999.

KEY WORDS

Drift
Drift eliminators
Cooling tower
PM_{10} emissions
TDS

APPENDIX B

BEST AVAILABLE CONTROL TECHNOLOGY FOR THE PROPOSED COMBUSTION TURBINES

B.1 NEW SOURCE PERFORMANCE STANDARDS

BACT is a case-by-case emission limitation for each applicable pollutant, based on the maximum degree of emission reduction after taking into account the energy, environmental, and economic impacts, and other costs. The BACT cannot be any less stringent than any applicable new source performance standards (NSPS) and consideration must be given to the applicable NSPS in the determination of BACT. This requirement also applies for any applicable National Emission Standard for Hazardous Air Pollutants promulgated under 40 CFR Part 61. For combustion turbines the applicable NSPS is 40 CFR Part 60, Subpart GG Standards of Performance for Stationary Gas Turbines.

B.1.1 SUBPART GG

The NSPS regulations (40 CFR, Subpart GG) applicable to gas turbines apply to:

1. Electric utility stationary gas turbines with a heat input at peak load of greater than 100 x 10^6 Btu/hr [40 CFR 60.332 (b)];
2. Stationary gas turbines with a heat input at peak load between 10 and 100 x 10^6 Btu/hr [40 CFR 60.332 (c)]; or
3. Stationary gas turbines with a manufacturer's rate base load at ISO conditions of 30 MW or less [40 CFR 60.332 (d)].

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

As noted from Table B-1, the NSPS NO_x emission limit can be adjusted upward to allow for fuel-bound nitrogen (FBN). For a fuel-bound nitrogen concentration of 0.015 percent or less, no increase in the NSPS is provided; for a fuel-bound nitrogen concentration of 0.03 percent, the NSPS is increased by 0.0012 percent or 12 parts per million (ppm). The NSPS NO_x emission limit adjustment is not affected by natural gas combustion.

B.1.2 SUBPART DA

On September 16, 1998, the NSPS for fossil fuel fired steam electric generators with more than 250 MMBtu/hr heat input were updated to include generally more stringent emission limitations for NO_x. These revised NSPS (Subpart Da) apply to any affected facility, which commenced construction after July 9, 1997. The applicable NO_x NSPS limit for firing coal, oil or natural gas, or a mixture of these, or any other fuels, is 1.6 lb/MW [40 CFR 60.44a(d)(1)]. These NSPS are applicable to the project.

B.2 BEST AVAILABLE CONTROL TECHNOLOGY

The "top-down" analysis for determining BACT, as provided for in EPA's Draft 1990 New Source Review Workshop Manual was considered in evaluating BACT for the Project. The procedure involves 5 steps: identification of control technologies, elimination of technically infeasible control technologies, a ranking of the control technologies, an evaluation of the effective control technologies and the selection of BACT.

The identification of control technologies is developed from the information obtained from BACT/LAER Information System (BLIS) database maintained at EPA's National Computer Center located at Research Triangle Park, North Carolina. While these data are comprehensive it is often not up to date with the most recent BACT/LAER decisions and separate contact with state agencies is required. LAER is distinctly different from BACT in that there is no consideration of economic, energy, or environmental impacts; if a control technology has previously been installed, it must be required as LAER. LAER is defined as follows:

> Lowest achievable emission rate means, for any source, the more stringent rate of emissions based on the following: (i) The most stringent emissions limitation which is contained in the implementation plan of any State of such class or category of stationary source, unless the owner or operator of the proposed stationary source demonstrates that such limitations are not achievable; or (ii) The most stringent emissions limitation which is achieved in practice by such class or category of stationary source. This limitation, when applied to a modification, means the lowest achievable emissions rate for the new or modified emissions units within the stationary source. In no event shall the application of this term permit a proposed new modified stationary source to emit any pollutant in excess of the amount allowable under applicable new source standards of performance (40 CFR 51, Appendix S.II, A.18).

The elimination of infeasible technologies is based on those engineering aspects that would preclude a technology's use due to physical, chemical or other engineering consideration. Control technologies that are technically feasible are ranked by control effectiveness, with determination of the environmental, economic and energy costs and benefits of the control technologies. This information forms the basis for the case-by-case consideration of environmental, energy and economic impacts. The "top" feasible control alterable is selected unless it can be rejected based on economic, environmental or energy considerations. This section of Appendix B presents information related to the proposed BACT emission limitation.

B.2.1 NITROGEN OXIDES

Identification of NO_x Control Technologies

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

Table B-2 presents a listing of the lowest achievable emission rates/best available control technology (LAER/BACT) decisions made by state environmental agencies and EPA regional offices for gas turbines including duct firing. This table was developed from the information obtained from BACT/LAER Information System (BLIS) database maintained at EPA's National Computer Center located at Research Triangle Park, North Carolina.

Historically, the most stringent NO_x controls for CTs established as LAER/BACT by state agencies were combustion controls with selective catalytic reduction (SCR) and combustion controls alone. SCR is a post-combustion control, while advanced dry low-NO_x combustors minimize the formation of NO_x in the combustion process. When SCR has been employed, dry low-NO_x combustion technology is used to minimize the NO_x emissions formed in the combustion process.

Wet injection was the first combustion technology introduced for combustion turbines (pre-1980's) and was the primary method of reducing NO_x emissions from CTs prior to the 1990's. Indeed, this method of control was first mandated by the NSPS to reduce NO_x levels to 75 parts per million by volume, dry (ppmvd) (corrected to 15 percent O_2 and heat rate). Development of improved wet injection combustors reduced NO_x concentrations to 25 ppmvd (corrected to 15 percent O_2) when burning natural gas. Wet injection is still the only means of reducing NO_x formation in the combustion process when firing oil.

The dry low-NO_x combustion technology has been developed and made available since the early 1990's for gas turbines to achieve emission levels of 25 ppmvd corrected to 15 percent O_2. More recently, however, CT manufacturers have developed dry low-NO_x combustors that can reduce NO_x concentrations to 9 ppmvd (corrected to 15 percent O_2) when firing natural gas.

SCR is an available and demonstrated control technology for NO_x control or combined cycle units, which has been installed or permitted in over 100 projects. Beginning in the late 1980s and early 1990s, SCR was initially installed on cogeneration facilities with capacities of 50 MW or less. Most of these projects were in California. Many of these initial SCR projects were located in the Southern California NO_2 nonattainment area where SCR was required not as BACT but as LAER, a more stringent requirement. As noted previously, there are distinct regulatory and policy differences between LAER and BACT. As discussed in Section 3.0, BACT involves an evaluation of the economic, environmental, and energy impacts of alternative control technologies. In contrast, LAER only considers the technical aspects of control.

More recently, projects with SCR have been installed throughout the US. A majority of these projects are natural gas-fired combined cycle facilities. The size of these projects ranges from 22 MW to over 500 MW. While many of the facilities have distillate oil as backup fuel, distillate oil generally is restricted by permit to 1,000 hours or less per CT.

Reported and permitted NO_x removal efficiencies of SCR range from 40 to over 80 percent of NO_x in the exhaust gas stream. The most common BACT emission limiting standard over the last two years is 3.5 ppmvd corrected to 15 percent O_2 or less for natural gas firing when using DLN and SCR. The most common emission limiting standard established as LAER is 2.5 ppmvd corrected to 15 percent O_2 or less for natural gas firing and using SCR.

Other available control technologies that have become available for controlling NO_x emissions from combustion turbines for include $SCONO_x$™ and XONON™. $SCONO_x$™ is an add-on control using absorption and chemical conversion to remove NO_x formed from combustion, while XONON™ is a catalytic combustion system integral to the turbine. Other potential technologies used in combustion process for NO_x removal include: NO_xOUT, Thermal DeNO_x, and NSCR.

Technology Descriptions and Feasibility

Wet Injection

The injection of water or steam in the combustion zone of CTs reduces the flame temperature with a corresponding decrease of NO_x emissions. The amount of NO_x reduction possible depends on the combustor design and the water-to-fuel ratio employed. An increase in the water-to-fuel ratio will cause a concomitant decrease in NO_x emissions until flame instability occurs. At this point, operation of the CT becomes inefficient and unreliable, and significant increases in products of incomplete combustion results (i.e., CO and VOC emissions). In "F" Class turbines using wet injection with gas firing, the NO_x emission rates in the range of 30 ppm have been demonstrated. However, wet injection is no longer offered for gas firing in "F" Class turbines. Wet injection is the only current feasible means of reducing NO_x emissions in the combustion process when firing oil.

Dry Low-NO_x Combustor

In the past several years, CT manufacturers have offered and installed machines with dry low-NO_x combustors. These combustors, which are offered on conventional machines manufactured by General Electric (GE), Siemens Westinghouse, Mitsubishi Heavy Industries (MHI) and ABB, can achieve NO_x concentrations of 25 ppmvd or less when firing natural gas. All these vendors have offered dry low-NO_x combustors on advanced heavy-duty industrial machines. Thermal NO_x formation is inhibited by using combustion techniques where the natural gas and combustion air are premixed before ignition. For the CT being considered for the project, the combustion chamber design includes the use of dry low-NO_x combustor technology. The NO_x emission level when firing natural gas at baseload conditions is 9 ppmvd (corrected to 15 percent O_2), a level which is guaranteed by the selected vendor for the project.

Selective Catalytic Reduction (SCR)

Selective Catalytic Reduction (SCR) uses ammonia (NH_3) to react with NO_x in the gas stream in the presence of a catalyst. NH_3, which is diluted with air to about 5 percent by volume, is introduced into the gas stream at reaction temperatures between 600°F and 750°F. The reactions are as follows:

$$4NH_3 + 4NO + O_2 = 4N_2 + 6H_2O$$

$$4NH_3 + 2NO_2 + O_2 = 3N_2 + 6H_2O$$

SCR operating experience, as applied to gas turbines, consists primarily of baseload natural-gas-fired installations either of cogeneration or combined cycle configuration. Exhaust gas temperatures of simple cycle CTs generally are in the range of 1,000°F, which exceeds the optimum range for SCR with base metal catalysts. All current SCR applications have the catalyst placed in the HRSG to achieve proper reaction conditions. This allows a relatively constant temperature for the reaction of NH_3 and NO_x on the catalyst surface.

The use of SCR has been primarily limited to combined-cycle facilities that burn natural gas with small amounts of fuel oil. Initially, the traditional metal catalysts used in SCR systems were contaminated by sulfur-containing fuels. For most fuel-oil-burning facilities, catalyst operation was discontinued, or the exhaust bypasses the SCR system. This was due to the formation of ammonium salts (ammonium sulfate and bisulfate) resulting from the reaction of NH_3 and sulfur combustion products. Ammonium bisulfate can be corrosive and could cause damage to the HRSG surfaces that follow the catalyst, as well as to the stack. Corrosion protection for these areas would be required with concomitant cost and technical requirements. Ammonium sulfate is emitted as particulate matter. While the formation of ammonium salts is primarily associated with oil firing, sulfur combustion products from natural gas also could form small amounts of ammonium salts. Ceramic and specially designed catalysts have been designed to overcome the problems with base-metal catalysts. The sulfur in No. 2 distillate oil has also been reduced from 0.5 percent available in the early 1990's to 0.05 percent. In addition, HRSG designs can accommodate the impacts of the formation of ammonium salts.

For combined cycle units, SCR is an available, technically feasible and demonstrated technology.

SCONO$_x$™ Process

SCONO$_x$™ is a NO_x and CO control system exclusively offered by Goal Line Environmental Technologies (GLET). GLET is a partnership formed by Sunlaw Energy Corporation and Advanced Catalyst Systems, Inc. In 1998, ABB acquired the exclusive license for the technology in the United States for control applications larger than 100 MW.

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

$$CO + \frac{1}{2} O_2 \rightarrow CO_2 \quad (1)$$

$$NO + \frac{1}{2} O_2 \rightarrow NO_2 \quad (2)$$

$$2NO_2 + K_2CO_3 \rightarrow CO_2 + KNO_2 + KNO_3 \qquad (3)$$

CO_2 produced by reaction (1) and (2) is released to the atmosphere as part of the CT/HRSG exhaust gas stream.

As shown in Reaction (3), the potassium carbonate catalyst coating reacts with NO_2 to form potassium nitrites and nitrates. Prior to saturation of the potassium carbonate coating, the catalyst must be regenerated. This regeneration is accomplished by passing a dilute hydrogen-reducing gas across the surface of the catalyst in the absence of O_2. Hydrogen in the reducing gas reacts with the nitrites and nitrates to form water and elemental nitrogen. CO_2 in the regeneration gas reacts with potassium nitrites and nitrates to form potassium carbonate; this compound is the catalyst absorber coating present on the surface of the catalyst at the start of the oxidation/absorption cycle. The SCONO$_x$™ regeneration cycle reaction is:

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

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

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

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

$$CH_4 + \frac{1}{2} O_2 + 1.88 N_2 \rightarrow CO + 2 H_2 + 1.88 N_2 \quad (5)$$

$$CO + 2 H_2 + H_2O + 1.88 NO_2 \rightarrow CO_2 + 3 H_2 + 1.88 N_2 \quad (6)$$

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

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

$$CO + \frac{1}{2} O_2 \rightarrow CO_2 \quad (7)$$

$$SO_2 + \frac{1}{2} O_2 \rightarrow SO_3 \quad (8)$$

$$SO_3 + \text{SORBER} \rightarrow [SO_3 + \text{SORBER}] \quad (9)$$

$$[SO_3 + \text{SORBER}] + 4 H_2 \rightarrow H_2S + 3 H_2O \quad (10)$$

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

Commercial experience to date with the SCONO$_x$™ control system is limited to one small combined cycle (CC) power plant located in Los Angeles. This power plant, owned by GLET partner Sunlaw Energy Corporation, utilizes a GE LM2500 turbine (30 MW size) equipped with water injection to control NO_x emissions to approximately 25 ppmvd. The SCONO$_x$™ control system was installed at the Sunlaw Energy facility in December 1996 and has achieved a NO_x exhaust concentration of 3.5 ppmv resulting in an approximate 85 percent NO_x removal efficiency.

A second $SCONO_x$™ system was installed at the Genetics Institute Facility in Andover, Massachusetts in late 1998. The system is installed on a 5-MW Caterpillar Solar Turbine with a Deltak boiler. The NO_x emission limit is 2.5 ppmvd at 15-percent O_2. ABB Environmental reports that the system is operating successfully, although there have been incidents of high NO_x emissions that ABB Environmental attributes to combustion control problems and not to the $SCONO_x$™ system.

XONON™ Catalytic Combustor

Catalytic combustors are being developed for low emission applications on turbines where the catalyst is internal to the combustion system. The XONON™ Combustion System is a catalytic combustion system developed by Catalytica Combustion Systems, Inc. that can achieve low emission levels of NO_x, CO and VOCs. The XONON" system combusts the fuel over a catalyst, reducing the temperature of combustion and providing for more complete combustion of the fuel. The system is referred to as "flameless combustion" where temperature are below those where limited NO_x formation occurs. However, the exhaust temperatures from a combustion turbine standpoint are still sufficient for the expansion of the gases through the turbine for power generation. Emission levels of NO_x at less than 2 ppm have been reported for the 1.5 MW Kawasaki gas turbine located at Sun Valley Power. Recently, this technology has been proposed for a 750 MW combined cycle facility. This facility, the Pastoria Energy Facility, is a project proposed by affiliates of Enron Corporation, which has a 15 percent interest in Catalytica Combustion Systems, Inc. Commercial operation is scheduled for the summer of 2003. Catalytica is currently working in collaboration with several gas turbine manufacturers including General Electric, Pratt & Whitney, Rolls Royce Allison and Solar.

NO_xOUT Process

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

$$CO(NH_2)_2 + 2NO + \frac{1}{2} O_2 \rightarrow 2N_2 + CO_2 + 2H_2O$$

The amount of urea required is most cost-effective when the treatment rate is 0.5 to 2 moles of urea per mole of NO_x. In addition to the original EPRI urea patents, Fuel Tech claims to have a number of proprietary catalysts capable of expanding the effective temperature range of the reaction to between 1,600°F and 1,950°F. Advantages of the system are as follows:

1. Low capital and operating costs as a result of use of urea injection, and
2. The proprietary catalysts used are nontoxic and nonhazardous, thus eliminating potential disposal problems.

Disadvantages of the system are as follows:

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

Commercial application of the NO_xOUT system is limited and the NO_xOUT system has not been demonstrated on any combustion turbine/HRSG unit.

The NO_xOUT process is not technically feasible for the proposed project because of the high application temperature of 1,600°F to 1,950°F. The maximum exhaust gas temperature of the "F" Class CT is about 1,100°F. Raising the exhaust temperature the required amount essentially would require installation of a heater. This would be economically prohibitive and would result in an increase in fuel consumption, an increase in the volume of gases that must be treated by the control system, and an increase in uncontrolled air emissions, including NO_x.

Thermal DeNO$_x$

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

The only known commercial applications of Thermal DeNO$_x$ are on heavy industrial boilers, large furnaces, and incinerators that consistently produce exhaust gas temperatures above 1,800°F. There are no known applications on or experience with CTs. Temperatures of 1,800°F require alloy materials constructed with very large piping and components since the exhaust gas volume would be increased by several times. As with the NO_xOUT process, high capital, operating, and maintenance costs are expected because of material requirements, an additional duct burner system, and fuel consumption. Uncontrolled emissions would increase because of the additional fuel burning.

Thus, the Thermal DeNO_x process will not be considered for the proposed project since its high application temperature makes it technically infeasible. The maximum exhaust gas temperature of an "F" Class combustion turbine is typically 1,100°F; the cost to raise the exhaust gas to such a high temperature is prohibitively expensive.

Nonselective Catalytic Reduction

Certain manufacturers, such as Engelhard, market a nonselective catalytic reduction system (NSCR) for NO_x control on reciprocating engines. The NSCR process requires a low oxygen content in the exhaust gas stream and high temperature (700°F to 1,400°F) in order to be effective. CTs have the required temperature but also have high oxygen levels (greater than 12 percent) and, therefore, cannot use the NSCR process. As a result, NSCR is not a technically feasible add-on NO_x control device for CTs.

<u>Technology Demonstration and Feasibility</u>

The combustion controls using dry low-NO_x combustors for the combustion turbine and low-NO_x burners for duct firing are available, demonstrated and technically feasible for combustion turbines in either simple cycle or combined cycle configuration. The dry low-NO_x combustion technology alone can achieve 9 ppm (corrected to 15 percent O_2 dry conditions) when firing natural gas.

The technical evaluation of post-combustion gas controls that include NO_xOUT, Thermal DeNO_x, and NSCR, and indicate that these processes have not been applied to either simple cycle combustion turbines or combined cycle systems and are technically infeasible for the project because of process constraints (e.g., temperature). The SCONO$_x$™ control technology is available but not considered to be technically feasible because it has not been commercially demonstrated on large "F" Class CTs. The CTs planned for the project, General Electric Frame 7FA units, each have a nominal generating capacity of 170 MW which are approximately seven times larger than the nominal 25-MW GE LM2500 utilized at the Sunlaw Energy Corporation Los Angeles facility. Technical problems associated with scale-up of the SCONO$_x$™ technology given the large differences in machine flow rates are unknown. Additional concerns with the $SCONO_x$™ control technology include process complexity (multiple catalytic oxidation/absorption/regeneration systems), reliance on only one supplier, relatively brief operating history of the technology, and distillate oil firing. While the XONON" catalytic combustion system is applied directly to the combustion turbine, application on a large combined cycle unit has not been demonstrated. For these reasons, the $SCONO_x$™ and XONON" are still considered in the commercial demonstration stage. SCR is commercially available, technically feasible and demonstrated for combined cycle units.

For combined cycle operation, the combination of dry low-NO_x combustion technology and water injection with SCR is a technically feasible alternative that can achieve a maximum degree of emission reduction. The combined technology is capable of achieving a NO_x emission levels of 3.5 ppm when firing natural gas (corrected to 15 percent O_2 dry conditions) 12 ppm when firing distillate oil (corrected to 15 percent O_2 dry conditions).

Below is a summary of the technical availability, demonstration and feasibility for the proposed project.

Combined Cycle

Technology	Status
Selective Catalytic Reduction	Available, Demonstrated and Feasible
Dry Low-NO_x Combustors	Available, Demonstrated and Feasible for gas firing
Wet Injection	Available, Demonstrated or Feasible for oil firing
$SCONO_x$	Available, Not Demonstrated
XOXON™	Not Demonstrated
Thermal De NO_x	Not Available or Feasible
NO_x Out	Not Available or Feasible
NSCR	Not Available or Feasible

SCR Cost Estimates

Tables B-3 and B-4 present the total capital and annualized cost to achieve 3.5 ppmvd corrected to 15 percent oxygen when firing natural gas using SCR and $SCONO_x$™ applied to combined cycle operation, respectively. The emission rate for oil firing for both SCR and $SCONO_x$™ is based on 12 ppmvd corrected to 15 percent oxygen. The costs were developed using EPA Cost Control Manual (EPA, 1990 & 1993) and vendor based estimates for each control system. Standard EPA recommended cost factors were used. A capital recovery period of 15 years was used for the capital costs. Tables B-3a and B-4a present the total capital and annualized cost to achieve 2.5 ppmvd corrected to 15 percent oxygen.

Comparison of Economic, Environmental, and Energy Impacts

Tables B-5 present a comparison of the economic, environmental, and energy impacts associated with the top control alternatives to achieve 3.5 ppmvd corrected to 15 percent oxygen when firing gas and 12 ppmvd corrected to 15 percent oxygen when firing oil. Table B-6 presents the potential emissions resulting from the formation of ammonium salts (i.e., particulate matter), ammonia slip and secondary emissions. Tables B-5a and B-6a present the economic, environmental and energy impacts associated with achieving 2.5 ppmvd corrected to 15 percent oxygen when firing natural gas.

B.2.2 CARBON MONOXIDE

Identification of CO Control Technologies

CO emissions are a result of incomplete or partial combustion of fossil fuel. Combustion design and catalytic oxidation are the control alternatives that are viable for the project. Table B-7 presents a listing of LAER/BACT decisions for CO emissions from combustion turbines. Combustion design is the more common control technique used in CTs. Sufficient time, temperature, and turbulence is required within the combustion zone to maximize combustion efficiency and minimize the emissions of CO. Combustion efficiency is dependent upon combustor design.

Catalytic oxidation is a post-combustion control that has been employed in CO nonattainment areas where regulations have required CO emission levels to be less than those associated with combustion controls alone. These installations have been required to use LAER technology and typically have CO limits less than 10 ppmvd (corrected to dry conditions).

Technology Description

In an oxidation catalyst control system, CO emissions are reduced by allowing unburned CO to react with oxygen at the surface of a precious metal catalyst, such as platinum. Combustion of CO starts at about 300°F, with an efficiency of 90 percent occurring at temperatures above 600°F. Catalytic oxidation occurs at temperatures 50 percent lower than that of thermal oxidation, which reduces the amount of thermal energy required. For CTs, the oxidation catalyst can be located directly after the CT. Catalyst size depends upon the exhaust flow, temperature, and desired efficiency.

Oxidation Catalyst Costs

Tables B-8 and B-9 present the capital and annualized cost for an oxidation catalyst installed in the HRSG.

Comparison of Economic, Environmental, and Energy Impacts

Table B-10 presents a comparison of the economic, environmental, and energy impacts associated with the top control alternatives for the combined cycle unit. Table B-11 presents the potential emissions resulting from the formation of ammonium salts (i.e., particulate matter), ammonia slip and secondary emissions. The latter results from generation lost due to the back pressure of the oxidation catalyst. The maximum CO impacts are less than 0.5 percent of the applicable ambient air quality standards. There would also be no secondary benefits, such as reducing acidic deposition, to reducing CO.

Table B-1. Federal NSPS for Electric Utility Stationary Gas Turbines

Pollutant	Emission Limitation[a]
Nitrogen Oxides[b]	0.0075 percent by volume (75 ppm) at 15 percent O_2 on a dry basis adjusted for heat rate and fuel nitrogen

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

[b] Standard is multiplied by 14.4/Y; where Y is the manufacturer's rated heat rate in kilojoules per watt at rated load or actual measured heat rate based on the lower heating value of fuel measured at actual peak load; Y cannot be greater than 14.4. Standard is adjusted upward (additive) by the percent of nitrogen in the fuel:

Fuel-Bound Nitrogen (percent by weight)	Allowed Increase NO_x Percent by Volume
$N \leq 0.015$	0
$0.015 < N \leq 0.1$	0.04(N)
$0.1 < N \leq 0.25$	0.004+0.0067(N-0.1)
$N > 0.25$	0.005

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

Source: 40 CFR 60 Subpart GG.

Table B-2. Summary of BACT Determinations for NO_x for Combined Cycle CTs, 1999-2001

Facility	State	Final Permit Issued	MW	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NOx Limit	Control Method	Avg. Time	Comments
Alabama Power, Plant Barry	AL	Aug-99	200	1	1	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm / 0.013 lb/MMBtu	DLN/SCR		
Mobile Energy, LLC - Hog Bayou	AL	Jan-99	200	1	1	GE 7FA (168 MW)	NG; FO	CC	8,760; 675 FO	3.5 ppm NG; 41 ppm w/ FO	DLN/SCR;WI		
Alabama Power - Theodore Cogeneration Facility	AL	Mar-99	210	1	1	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm/ 0.013 lb/MMBtu	DLN/SCR		
Tenaska Alabama Partners	AL	Nov-99	846	3	3	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	3.95 ppm NG; 11.3 ppm FO	DLN/SCR; WI/SCR		
Georgia Power - Goat Rock	AL	Apr-00	-	8	8	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm/ 0.013 lb/MMBtu	DLN/SCR		
Georgia Power - Goat Rock (revision of above PSD application)	AL	Apr-01	2,460	8	8	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm/ 0.013 lb/MMBtu	DLN/SCR		
Alabama Electric Cooperative - Gantt Plant	AL	Mar-00	500	2	2	SW 501F (166 MW)	NG	CC	8,760	3.5 ppm / 0.013 lb/MMBtu	DLN/SCR		
South Eastern Energy Corp.	AL	Jan-01	1,500	6	6 if CC	GE 7FA or SW 501F	NG	SC or CC	8,760	9 or 25 or 3.5 ppm	DLN if SC/SCR if CC		For NO_x and CO: SC w/GE or SC w/SW501F or CC (either)
Calpine Solutia - Decatur	AL	Jun-00	700	3	3	SW501F (180 MW)	NG	CC	8,760	3.5 ppm/ 0.013 lb/MMBtu	SCR		
Calpine BP Amoco	AL	Jun-00	700	3	3	SW501F (180 MW)	NG	CC	8,760	3.5 ppm/ 0.013 lb/MMBtu	SCR		
Tenaska Alabama II Generating Station	AL	Feb-01	900	3	3	GE 7FA or Mitsubishi M501F	NG; FO	CC	8,760; 720 FO	0.013/0.048 lb/mmbtu NG/FO - GE; 0.013/0.046 lb/mmbtu	SCR/WI		
Hillabee Energy Center	AL	Jan-01	700	2	2	SW501G (229 MW)	NG	CC	8,760	3.5 ppm	DLN/SCR		PA = Power Augmentation, DB= Duct Burning
Duke Energy - Alexander City	AL	Feb-01	1,260	10	2	GE 7FA & 7EA	NG	CC & SC	8,760 CC; 2,500 SC	3.5 ppm (0.013 lb/mmBtu) CC; 9/12 ppm (0.033 lb/mmBtu)	SCR - CC, DLN-SC	an/1-hr	8 SC units and 2 CC units
GenPower - Kelly, LLC	AL	Jan-01	1,260	4	4	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	SCR		
Blount County Energy	AL	Jan-01	800	3	3	"F" Class (170 MW)	NG	CC	8,760	0.013 lb/mmBtu (30.7 lb/hr)	SCR	3-hr	
Alabama Power - Autaugaville	AL	Jan-01	1,260	4	4	"F" Class (170 MW)	NG	CC	8,760	3.5 ppm (0.013 lb/mmBtu)	SCR		
Tenaska Alabama IV Partners	AL	draft permit	1,840	6	6	Mit 501F (170 MW)	NG; FO	CC	8,760; 720 FO	3.5 ppm NG; 12 ppm FO	SCR		SCONOx - $6,145/ton NO_x; CatOx- $1,506/ton CO
Duke Energy Autauga, LLC	AL	applic. under review	630	2	2	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	SCR		SCONOx - $18760/ton NO_x; CatOx- $5,006/ton CO
Kissimmee Utility Authority, Cane Island Power Park -Unit 3	FL	draft permit	250	1	0	GE 7FA (167 MW)	NG; FO	CC	8,760; 720 FO	3.5 ppm NG; 15 ppm FO	SCR		
Duke Energy - New Smyrna Beach	FL	draft permit	500	2	0	GE 7FA (165 MW)	NG	CC	8,760	9 ppm or 6 ppm	DLN or SCR		
Lake Worth Generation	FL	Nov-99	244	1	1	GE 7FA (170 MW)	NG; FO	CC	8,760; 1,000 FO	9 ppm NG; 42 ppm FO	DLN; WI		
Hines Energy (FPC)	FL	project dropped	500	2	0	SW 501F (165 MW)	NG; FO	CC	8,760; 1,000 FO	6 ppm NG - full load; 42 ppm FO	SCR; WI		
Gulf Power - Smith Station	FL	Jul-00	340	2	2	GE 7FA (170 MW)	NG	CC	8,760	82.9 lb/hr w/DB, 113.2 lb/hr w/ DB & SA	DLN	30-day	Netting out of PSD for NO_x and CO; SA = steam augmentation
Florida Power & Light - Sanford	FL	Sep-99	2,200	8	0	GE 7FA (170 MW)	NG, FO	CC	8,760; 500 FO	9 ppm NG; 42 ppm FO	DLN; WI		Repowering, 4 units FO
Gainesville Regional Utilities, Kelly Generating Station	FL	Feb-00	133	1	0	GE 7EA (83 MW)	NG; FO	CC	8,760; 1,000 FO	9 ppm NG; 42 ppm FO	DLN; WI		Netting out of PSD review for NO_x
Calpine Osprey Energy Center	FL	Jul-01	527	2	2	SW 501FD (170 MW)	NG	CC	8,760	3.5 ppm	DLN/SCR	24-hr Block	2,800 hr/yr - Power Aug. mode

Table B-2. Summary of BACT Determinations for NO_x for Combined Cycle CTs, 1999-2001

Facility	State	Final Permit Issued	MW	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NOx Limit	Control Method	Avg. Time	Comments
Hines Energy (FPC)	FL	Jun-01	530	2	0	SW 501FD (170 MW)	NG; FO	CC	8,760; 1,000 FO	3.5 ppm NG; 12 ppm FO	SCR; WI	24-hr Block	SCONOx - $16,712/ton NO_x; CatOx - $2,130/ton CO
CPV - Gulfcoast	FL	Feb-01	250	1	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	3.5 ppm NG; 10 ppm FO	SCR		SCONOx - no cost eval.; CatOx - $4,350/ton CO
TECO Gannon/Bayside	FL	Mar-01	1,728	7	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 876 FO	3.5 ppm NG; 16.4 ppm FO	SCR		Repowering project: netting out of NO_x, CO, PM_{10} and SO_2 review (subject to VOC reveiw)
South Pond Energy Park	FL	draft permit	600	3	0	GE 7FA (170 MW)	NG; FO	SC/CC	3,390/8,760; 720 FO	10 ppm (9 initial)/3.5 ppm NG; 42/15 ppm FO	DLN/SCR; WI	3-hr	2 SC CT and 1 CC CT also capable of operating in SC mode.
North Pond Energy Park	FL	applic. under review	430	2	0	GE 7FA (170 MW)	NG; FO	SC/CC	3,390/8,760; 720 FO	10 ppm (9 initial)/3.5 ppm NG; 42/15 ppm FO	DLN/SCR; WI	3-hr	1 SC CT and 1 CC CT also capable of operating in SC mode.
Calpine Blue Heron Energy Center	FL	draft permit	1,080	4	4	SW 501F (170 MW)	NG	CC	8,760	3.5 ppm	DLN/SCR		base/duct burner/power aug./60-70% load; SCONOx - $9,982/ton NO_x; CatOx - $1,553/ton CO
Jacksonville Electric Authority - Brandy Branch (revision)	FL	draft permit	200	0	2	GE 7FA (170 MW)	NG; FO	CC	8760; 288 FO	3.5 ppm NG; 15 ppm FO	SCR		Conversion of 2 SC units to 2 CC units
CPV - Atlantic Power	FL	May-01	250	1	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	3.5 ppm NG; 10 ppm FO	SCR		PA = Power Augmentation
Orlando Utilities - Curtis H Stanton Energy Center	FL	Sep-01	633	2	2	GE 7FA (170 MW)	NG; FO	CC	8,760; 1000 FO	3.5 ppm NG; 10 ppm FO	SCR		
Broward Energy Center	FL	draft permit	775	4	0	GE 7FA (175 MW)	NG	CC/SC	8,760/5,000	3.5 ppm/9 ppm	SCR/DLN	24-hr	* 1 CC w/unfired HRSG & 3 SC; PA = Power Augmentation
Belle Glade Energy Center	FL	draft permit	600	3	0	GE 7FA (175 MW)	NG	CC/SC	8,760/5,000	3.5 ppm/9 ppm	SCR/DLN	24-hr	* 1 CC w/unfired HRSG & 2 SC; PA = Power Augmentation
Manatee Energy Center	FL	draft permit	600	3	0	GE 7FA (175 MW)	NG	CC/SC	8,760/5,000	3.5 ppm/9 ppm	SCR/DLN	24-hr	* 1 CC w/unfired HRSG & 2 SC; PA = Power Augmentation
CPV Pierce Power Generation Facility	FL	Aug-01	250	1	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	2.5 ppm NG; 10 ppm FO	SCR	24-hr	PA limited to 2,000 hr/yr
Fort Pierce Repowering Project	FL	draft permit	180	1	1	SW 501F (180 MW)	NG; FO	CC/SC	8,760; 1,000 FO/2,000; 500 FO	3.5 ppm NG; 12 ppm FO/25 ppm NG; 42 ppm FO	SCR/DLN; WI		CT will operate in both CC and SC modes
TECO Bayside Power Station	FL	draft permit	1,032	4	0	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	SCR		Repowering Project: Netting out of PSD for NO_x, SO_2, VOC, lead and SAM (subject for PM_{10} and CO)
Georgia Power - Wansley (Oglethorpe Power)	GA	Jul-00	2,280	8	8	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm / 0.013 lb/MMBtu	DLN/SCR	30 day	
Duke Energy Murray, LLC	GA	Feb-01	1,240	4	4	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	DLN/SCR		
Duke Energy Buffalo Creek, LLC	GA	applic. under review	620	2	2	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	DLN/SCR		SCONOx - $19,948/ton NO_x; CatOx - $2,469/ton CO
Augusta Energy LLC	GA	draft permit	750	3	3	GE 7FA (170 MW)	NG; FO	CC	8,760; 1,000 FO	3.5 ppm NG; 42 ppm FO	SCR; WI		SCONOx - $17,490/ton NO_x; CatOx - $4,133/ton CO
GenPower McIntosh	GA	applic. under review	528	2	2	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	SCR		
Monroe Power Co.	GA	applic. under review	525	2	0	GE 7FA (170 MW)	NG	SC/CC	8,760	12/3.5 ppm	DLN/SCR		Initially SC, but later converting to CC
Peace Valley Generation Co., LLC	GA	applic. under review	1,550	6	4	F" Class	NG	CC/SC	8,760/2,500	3.5/9 ppm	SCR/DLN;		
Duke Energy Tift	GA	applic. under review	620	2	2	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	SCR		SCONOx - $16,274/ton NO_x; CatOx - $2,095/ton CO
CPV Terrapin, LLC	GA	applic. under review	800	3	3	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	3.5 ppm NG; 5.4 ppm (NG w/DB); 8.0 ppm FO	SCR		

Table B-2. Summary of BACT Determinations for NO_x for Combined Cycle CTs. 1999-2001

Facility	State	Final Permit Issued	MW	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NOx Limit	Control Method	Avg. Time	Comments
Kinder Morgan Georgia, LLC - Tift Power	GA	applic. under review	560	7	7	1 - GE 7EA & 6 - LM6000	NG	CC	8,760; 3,760 (part load)	9 ppm & 22 ppm	DLN & WI	annual	
Hartwell Development Co.	GA	applic. under review	564	2	0	GE 7FA (176 MW)	NG	CC	8,760	3.5 ppm	SCR		SCONOx - \$35,422/ton NO_x; CatOx - \$4,964/ton CO
Kentucky Pioneer Energy	KY	Jun-01	540	2	0	GE 7FA (197 MW)	syngas/ NG	CC	8,760	15/20 ppm	Steam Injection	3-hr	
Duke Energy Hinds, L.L.C.	MS	Apr-00	520	2	0	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	DLN/SCR		
Duke Energy Attala, L.L.C.	MS	Apr-00	520	2	0	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	DLN/SCR		
Cogentrix Energy, Southaven Power Project	MS	draft permit	800	3	3	GE 7FA (170 MW)	NG	CC	8,760	4.5 ppm (10.8 ppm w/ DB)	DLN/SCR		
Cogentrix Energy, Caledonia Power Project	MS	Mar-01	800	3	3	GE 7FA (182 MW)	NG	CC	8,760	3.5 ppm (w/DB)	DLN/SCR		revised application to add SCR
GenPower - McAdams LLC	MS	draft permit	528	2	2	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	DLN/SCR	24-hr	
Lone Oak Energy Center	MS	draft permit	800	3	3	F" Class (180 MW)	NG	CC	8,760	3.5 ppm	SCR		Base/PA/PA+DF/DF
Lee Power Partners	MS	draft permit	1,000	4	4	F" Class (170 MW)	NG	CC	8,760	3.5 ppm	SCR		
LSP-Pike Energy LLC	MS	draft permit	1,100	4	4	F" Class (170 MW)	NG	CC	8,760	4.5 ppm	SCR		
Magnolia Energy	MS	draft permit	900	3	3	F" Class (170 MW)	NG	CC	8,760	3.5 ppm	SCR		
Hines Energy Facility	MS	Jan-00	340	2	?	170 MW each	NG	CC	8,760	3.5 ppm	DLN, SCR		
Reliant Energy - Choctaw Co., LLC	MS	draft permit	844	3	3	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	DLN, SCR	30-day	SCONOx - \$48,663/ton NO_x; CatOx - \$3,550/ton CO
Crossroads Energy Center	MS	applic. under review	580	2	2	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	SCR		SCONOx - \$23,400/ton NO_x; CatOx - \$11,039/ton CO
Choctaw Gas Generation, LLC	MS	applic. under review	700	2	2	SW 501G (250 MW)	NG	CC	8,760	3.5 ppm	SCR		
Duke Energy Homochitto, LLC	MS	applic. under review	630	2	2	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	SCR	24-hr	
Granite Power Partners II (Batesville)	MS	applic. under review	300	1	1	SW 501F (230 MW)	NG	CC	8,760	3.5 ppm	SCR		
Carolina Power & Light, Richmond Co. (2nd revision - new configuration)	NC	applic. under review	2,040	9	0	GE 7FA (170 MW)	NG; FO	CC/SC	8,760/2,000; 1,000 FO	3.5/9 ppm NG; 13/42 ppm FO	SCR/DLN; SCR/WI	24-hr	Reconfiguration of facility: 6 CC and 3 SC CTs
Carolina Power & Light, Rowan Co. (revision)	NC	draft permit	1,110	2	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 1,000 FO	9 ppm NG; 42 ppm FO	DLN; WI		Modification of previous permit to switch 2 SC -> CC
Butler-Warner Generation Plant	NC	applic. under review	500	2	0	GE 7FA (170 MW)	NG; FO	SC & CC	8,760; 500 FO	9 ppm NG; 42 ppm FO	DLN; WI		
GenPower Earleys, LLC	NC	applic. under review	528	2	2	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	SCR		SCONOx - \$21,942/ton NO_x; CatOx - \$3,246ton CO
Santee Cooper, Rainey Generating Station	SC	Apr-00	870	4	0	GE 7FA (170 MW)	NG, FO	2 CC, 2 SC	8,760; 1,000 FO	9 ppm NG; 42 ppm FO	DLN; WI		
SC Electric & Gas - Urquhart	SC	Sep-00	444	2	0	GE 7FA (150 MW)	NG, FO	CC	8,760; 4,380 FO	45 ppm	DLN		Netted out of NO_x, SO_2 and PM_{10} PSD Review
Columbia Energy	SC	Apr-01	515	2	2	GE 7FA (170 MW)	NG, FO	CC	8,760; 1,000 FO	3.5 ppm NG; 12 ppm FO	DLN/SCR; WI		SCONOx - no analysis; CatOx - \$1,611/ton CO
GenPower Anderson	SC	draft permit	640	2	2	GE 7FA (170 MW)	NG	CC	8760	3.5 ppm	DLN/SCR		
Vanderbilt University	TN	May-00	10	2	2	GE PGT5B (5.2 MW)	NG	CC	8,760	25 ppm	DLN		

Table B-2. Summary of BACT Determinations for NO_x for Combined Cycle CTs, 1999-2001

Facility	State	Final Permit Issued	MW	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NOx Limit	Control Method	Avg. Time	Comments
Memphis Generation LLC	TN	draft permit	1,050	4	0	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	SCR		Phase I - 1 CT (up to 7% total plant heat input from refinery fuel gas), Phase II - 3 CTs (up to 2% total plant heat input from refinery fuel gas)
Haywood Energy Center (Calpine)	TN	applic. under review	900	3	3	SW, GE 7FA or GE F7B	NG; FO	CC	8,760	3.5 ppm NG; 42 ppm FO	DLN/SCR; WI		
TVA - Franklin	TN	applic. under review	610	2	2	GE 7FA (195 MW)		CC	8,760	3.5 ppm	SCR		

Abbreviations:
GE = General Electric
SW = Seimens Westinghouse
NG = Nat. Gas
FO = Fuel Oil
DB = Duct Burner
SC = Simple Cycle
CC = Combined Cycle
DLN = Dry-Low NO_x
WI = Water Injection
SCR = Selective Catalytic Reduction
CatOx = Catalytic Oxidation
GCP = Good Combustion Practices

Source: http://www.epa.gov/region4/air/permits/national_ct_list.xls (2001)

Table B-3. Capital Cost for Selective Catalytic Reduction and SCONOx™ for the GE Frame 7FA Combined Cycle Combustion Turbine
(3.5 ppmvd corrected for gas firing and 12 ppmvd corrected for oil firing)

Cost Component	Costs for SCR	Costs for SCONOx™	Basis of Cost Component
Direct Capital Costs			
Pollution Control Equipment	$1,088,000	$14,750,000	Vendor Estimates
Ammonia Storage Tank	$124,484	$0	$35 per 1,000 lb mass flow developed from vendor quotes
Flue Gas Ductwork	$44,505	$69,725	Vatavauk,1990
Instrumentation	$50,000	$50,000	Additional NO_x Monitor and System
Taxes	$65,280	$885,000	6% of SCR Associated Equipment and Catalyst
Freight	$54,400	$737,500	5% of SCR Associated Equipment
Total Direct Capital Costs (TDCC)	$1,426,669	$16,492,225	
Direct Installation Costs			
Foundation and supports	$114,134	1,319,378	8% of TDCC and RCC;OAQPS Cost Control Manual
Handling & Erection	$199,734	2,308,912	14% of TDCC and RCC;OAQPS Cost Control Manual
Electrical	$57,067	659,689	4% of TDCC and RCC;OAQPS Cost Control Manual
Piping	$28,533	329,845	2% of TDCC and RCC;OAQPS Cost Control Manual
Insulation for ductwork	$14,267	164,922	1% of TDCC and RCC;OAQPS Cost Control Manual
Painting	$14,267	164,922	1% of TDCC and RCC;OAQPS Cost Control Manual
Site Preparation	$5,000	$5,000	Engineering Estimate
Buildings	$15,000	$15,000	Engineering Estimate
Total Direct Installation Costs (TDIC)	$448,001	$4,967,668	
Total Capital Costs (TCC)	$1,874,670	$21,459,893	Sum of TDCC, TDIC and RCC
Indirect Costs			
Engineering	$142,667	$1,649,223	10% of Total DirectCapital Costs; OAQPS Cost Control Manual
PSM/RMP Plan	$50,000	$0	Engineering Estimate
Construction and Field Expense	$71,333	$824,611	5% of TDCC; OAQPS Cost Control Manual
Contractor Fees	$142,667	$1,649,223	10% of TDCC; OAQPS Cost Control Manual
Start-up	$28,533	$329,845	2% of TDCC; OAQPS Cost Control Manual
Performance Tests	$14,267	$164,922	1% of TDCC; OAQPS Cost Control Manual
Contingencies	$42,800	$494,767	3% of TDCC; OAQPS Cost Control Manual
Total Indirect Capital Cost (TInCC)	$492,267	$5,112,590	
Total Direct, Indirect and Capital Costs (TDICC)	$2,366,937	$26,572,482	Sum of TCC and TInCC

Table B-4. Annualized Cost for Selective Catalytic Reduction and SCONOx™ for the GE Frame 7FA in Combined Cycle Operation
(3.5 ppmvd corrected for gas firing and 12 ppmvd corrected for oil firing)

Cost Component	Costs for SCR	Costs for SCONOx™	Basis of Cost Component
Direct Annual Costs			
Operating Personnel	$18,720	$37,440	24 hours/week at $15/hr for SCR; SCONOx 2 times SCR costs
Supervision	$2,808	$5,616	15% of Operating Personnel;OAQPS Cost Control Manual
Ammonia	$117,422	$0	$300 per ton for Aqueous NH_3
PSM/RMP Update	$15,000	$0	Engineering Estimate
Inventory Cost	$22,875	$34,313	Capital Recovery (10.98%) for 1/3 catalyst for SCR; SCONOx 1.5 times SCR
Catalyst Cost	$208,333	$312,500	3 years catalyst life; Based on Vendor Budget Estimate
Contingency	$11,555	$11,696	3% of Direct Annual Costs
Total Direct Annual Costs (TDAC)	$396,713	$401,565	
Energy Costs			
Electrical	$28,032	$70,080	80kW/h for SCR @ $0.04/kWh times Capacity Factor; 200 kW for SCONOx
MW Loss and Heat Rate Penalty	$321,312	$642,625	0.3% output for SCR; 0.6% for SCONOx; EPA, 1993
Steam Costs for SCONOx	$0	$690,567	17,795 lb/hr 600 °F, 85 psig, steam (1,329 Btu/lb steam); 90% boiler eff.; $3/mmBtu
Natural Gas for SCONOx	$0	$48,737	80 lb/hr; 0.044 lb/scf; 1,020 Btu/scf; $3/mmBtu
Total Energy Costs (TEC)	$349,344	$1,452,009	
Indirect Annual Costs			
Overhead	83,370	25,834	60% of Operating/Supervision Labor and Ammonia
Property Taxes	23,669	265,725	1% of Total Capital Costs
Insurance	23,669	265,725	1% of Total Capital Costs
Annualized Total Direct Capital	259,890	2,917,659	10.98% Capital Recovery Factor of 7% over 15 years times sum of TDICC
Total Indirect Annual Costs (TIAC)	$390,599	$3,474,942	
Total Annualized Costs	$1,136,656	$5,328,516	Sum of TDAC, TEC and TIAC
Cost Effectiveness	$4,216	$19,765	per ton of NO_x Removed
	269.59	269.59	tons NOx removed /year; 3.5 ppmvd corrected to 15% oxygen

Table B-5. Comparison of Alternative BACT Control Technologies for NOx on One CT/HRSG

	Alternative BACT Control Technologies		
	DLN/WI Only	DLN/WI with SCR (3.5/12 ppmvd corrected)	DLN/WI with SCONOx™ (3.5/WI ppmvd corrected)
Technical Assessment	Feasible	Available, Feasible and Demonstrated	Not Demonstrated
Economic Impact [a]			
Capital Costs	included	$2,366,937	$26,572,482
Annualized Costs	included	$1,136,656	$5,328,516
Cost Effectiveness (per ton of Nox removed)			
Total	NA	$4,216	$19,765
Environmental Impact [b]			
Total NOx (TPY)	401	131.8	131.8
NOx Reduction (TPY)	NA	-270	-270
Ammonia Emissions (TPY)	0	112	0
PM Emissions (TPY)	0	11.9	0
Secondary Emissions (TPY)	0	6.2	41.3
Net Emission Reduction (TPY)	NA	-140	-228
Addition Greenhouse Gas (as CO2; tons/year)	0	3,414	22,905
Energy Impacts [c]			
Energy Use (kWh/yr) - Total	0	5,232,523	35,108,528
Energy Use (kWh/yr) - Back Pressure	0	4,531,723	9,063,446
Energy Use (kWh/yr) - Other	0	700,800	26,045,082
Energy Use (Equivalent Residential Customers/year)	0	436	2,926
Energy Use (mmBtu/yr) at 10,000 Btu/kWh	0	53,900	361,652
Energy Use (mmcf/yr) at 1,000 Btu/cf for natural gas	0	54	362
Energy Use (percent of combustion turbine output)	0	0.35%	2.32%

[a] See Tables B-3, B-4, and B-5 for detailed development of capital costs (including recurring costs) and annualized costs.

[b] See emission data presented in Table B-7.

[c] Energy impacts are estimated due to the lost energy from heat rate penalty and electrical usage for the SCR operation at 8,760 hours per year. Lost energy for SCR is based on 0.3 percent of 166 MW. SCR electrical usage is based on 0.080 MWh per SCR system. Lost Energy for SCONOx™ includes 0.6 percent of turbine output and steam usage. SCONOx™ electrical usage based on 0.2 MW/hr per system.

Table B-5a. Comparison of Alternative BACT Control Technologies for NOx on One CT/HRSG

	Alternative BACT Control Technologies		
	DLN/WI Only	DLN/WI with SCR (2.5/12 ppmvd corrected)	DLN/WI with SCONOx™ (2.5/WI ppmvd corrected)
Technical Assessment	Feasible	Available, Feasible and Demonstrated	Not Demonstrated
Economic Impact [a]			
Capital Costs	included	$2,645,725	$26,572,482
Annualized Costs	included	$1,479,017	$5,682,303
Cost Effectiveness (per ton of Nox removed)			
Total	NA	$4,918	$18,894
Incremental from 3.5 ppm			
Environmental Impact [b]			
Total NOx (TPY)	401	100.7	100.7
NOx Reduction (TPY)	NA	301	301
Ammonia Emissions (TPY)	0	112	0
PM Emissions (TPY)	0	11.9	0
Secondary Emissions (TPY)	0	7.0	41.3
Net Emission Reduction (TPY)	NA	-170	-259
Additional Greenhouse Gas (as CO_2; tons/year)	0	3,857	22,905
Energy Impacts [c]			
Energy Use (kWh/yr)	0	5,912,282	35,108,528
Energy Use (kWh/yr) - Back Pressure	0	5,211,482	9,063,446
Energy Use (kWh/yr) - Other	0	700,800	26,045,082
Energy Use (Equivalent Residential Customers/year)	0	493	2,926
Energy Use (mmBtu/yr) at 10,000 Btu/kWh	0	60,902	361,652
Energy Use (mmcf/yr) at 1,000 Btu/cf for natural gas	0	61	362
Energy Use (percent of combustion turbine output)	0	0.39%	2.32%

[a] See Tables B-3a, B-4a, and B-5a for detailed development of capital costs (including recurring costs) and annualized costs.

[b] See emission data presented in Table B-7a.

[c] Energy impacts are estimated due to the lost energy from heat rate penalty and electrical usage for the SCR operation at 8,760 hours per year. Lost energy for SCR is based on 0.345 percent of 166 MW. SCR electrical usage is based on 0.080 MWh per SCR system. Lost Energy for SCONOx™ includes 0.6 percent of turbine output and steam usage. SCONOx™ electrical usage based on 0.2 MW/hr per system.

Table B-6. Maximum Potential Incremental Emissions (TPY) with Selective Catalytic Reduction (SCR) and SCONOx™

	Incremental Emissions (tons/year) of SCR			Incremental Emissions (tons/year) of SCONOx™		
Pollutants	Primary	Secondary	Total	Primary	Secondary	Total
Particulate	11.92	0.20	12.12		1.31	1.31
Sulfur Dioxide		0.07	0.07		0.49	0.49
Nitrogen Oxides	-269.59	3.59	-266.00	-269.59	24.11	-245.48
Carbon Monoxide		2.16	2.16		14.47	14.47
Volatile Organic Compounds		0.14	0.14		0.95	0.95
Ammonia	111.82					
Total:	-145.85	6.16	-139.69	-269.59	41.32	-228.27
Carbon Dioxide (all energy requirements)		3,413.67	3,413.67		22,904.63	22,904.63

Basis:	SCR	SCONOx™	SCONOx™
Lost Energy (mmBtu/year)	53,900	361,652 total	245,607 steam and natural gas only

Secondary Emissions (lb/mmBtu): Assumes natural gas firing in NOx controlled steam unit.

Particulate	0.0072
Sulfur Dioxide	0.0027
Nitrogen Oxides w/LNB	0.1333
Carbon Monoxide	0.0800
Volatile Organic Compounds	0.0052

(Note: Seconary emissions of criteria pollutants for SCONOx based on the total lost energy minus steam and natural gas since emissions of these pollutants will be controlled in the proposed unit. Emissions of CO_2 will result for all uses.)

Reference: Table 1.4-1 and 1.4-2, AP-42, Version 2/98

Table B-6a. Maximum Potential Incremental Emissions (TPY) with Selective Catalytic Reduction (SCR) and SCONOx™ (2.5 ppm)

	Incremental Emissions (tons/year) of SCR			Incremental Emissions (tons/year) of SCONOx™		
Pollutants	Primary	Secondary	Total	Primary	Secondary	Total
Particulate	11.92	0.22	12.14		1.31	1.31
Sulfur Dioxide		0.08	0.08		0.49	0.49
Nitrogen Oxides	-300.74	4.06	-296.68	-300.74	24.11	-276.63
Carbon Monoxide		2.44	2.44		14.47	14.47
Volatile Organic Compounds		0.16	0.16		0.95	0.95
Ammonia	111.82					
Total:	-177.00	6.96	-170.04	-300.74	41.32	-259.42
Carbon Dioxide (all energy requirements)		3,857.14	3,857.14		22,904.63	22,904.63

Basis:	SCR	SCONOx™	SCONOx™
Lost Energy (mmBtu/year)	60,902	361,652 total	245,607 steam and natural gas only

Secondary Emissions (lb/mmBtu): Assumes natural gas firing in NOx controlled steam unit.

Particulate	0.0072
Sulfur Dioxide	0.0027
Nitrogen Oxides w/LNB	0.1333
Carbon Monoxide	0.0800
Volatile Organic Compounds	0.0052

(Note: Seconary emissions of criteria pollutants for SCONOx based on the total lost energy minus steam and natural gas since emissions of these pollutants will be controlled in the proposed unit. Emissions of CO_2 will result for all uses.)

Reference: Table 1.4-1 and 1.4-2, AP-42, Version 2/98

Table B-7. Summary of BACT Determinations for CO for Combined Cycle CTs, 1999-2001

Facility	State	Final Permit Issued	# of New MW	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	CO Limit	Control Method	Avg. Time	Comments
Alabama Power, Plant Barry	AL	Aug-99	200	1	1	GE 7FA (170 MW)	NG	CC	8,760	0.060 lb/MMBtu	GCP		
Mobile Energy, LLC - Hog Bayou	AL	Jan-99	200	1	1	GE 7FA (168 MW)	NG; FO	CC	8,760; 675 FO	0.040 lb/MMBtu NG; 0.058 lb/mmBtu FO	GCP		
Alabama Power - Theodore Cogeneration Facility	AL	Mar-99	210	1	1	GE 7FA (170 MW)	NG	CC	8,760	0.086 lb/MMBtu	GCP		
Tenaska Alabama Partners	AL	Nov-99	846	3	3	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	32.9 ppm NG; 46.7 ppm NG/FO	GCP		
Georgia Power - Goat Rock	AL	Apr-00	-	8	8	GE 7FA (170 MW)	NG	CC	8,760	0.086 lb/MMBtu	GCP		
Georgia Power - Goat Rock (revision of above PSD application)	AL	Apr-01	2,460	8	8	GE 7FA (170 MW)	NG	CC	8,760	0.086 lb/MMBtu	GCP		
Alabama Electric Cooperative - Gantt Plant	AL	Mar-00	500	2	2	SW 501F (166 MW)	NG	CC	8,760	0.057 lb/MMBtu	GCP		
South Eastern Energy Corp.	AL	Jan-01	1,500	6	6 if CC	GE 7FA or SW 501F	NG	SC or CC	8,760	9 or 19 or 22 ppm	GCP		For NO_x and CO: SC w/GE or SC w/SW501F or CC (either)
Calpine Solutia - Decatur	AL	Jun-00	700	3	3	SW501F (180 MW)	NG	CC	8,760	0.117 lb/mmBtu	GCP		
Calpine BP Amoco	AL	Jun-00	700	3	3	SW501F (180 MW)	NG	CC	8,760	0.117 lb/mmBtu	GCP		
Tenaska Alabama II Generating Station	AL	Feb-01	900	3	3	GE 7FA or Mitsubishi M501F	NG; FO	CC	8,760; 720 FO	0.037/0.047/0.089 lb/mmbtu (base/PA/FO) - GE; 0.088/0.116/0.35 lb/mmbtu (base/PA/FO) - Mit	GCP		
Hillabee Energy Center	AL	Jan-01	700	2	2	SW501G (229 MW)	NG	CC	8,760	0.023/0.076 lb/mmBtu (w/PA and/or DB)	GCP		PA = Power Augmentation, DB= Duct Burning
Duke Energy - Alexander City	AL	Feb-01	1,260	10	2	GE 7FA & 7EA	NG	CC & SC	8,760 CC; 2,500 SC	0.059 lb/mmBtu (130 lb/hr) CC; 0.09 lb/mmBtu (80 lb/hr) SC	GCP		8 SC units and 2 CC units
GenPower - Kelly, LLC	AL	Jan-01	1,260	4	4	GE 7FA (170 MW)	NG	CC	8,760	9 ppm, 14 ppm (w/DB)	GCP		
Blount County Energy	AL	Jan-01	800	3	3	"F" Class (170 MW)	NG	CC	8,760	0.033 lb/mmBtu (77.7 lb/hr)	GCP		
Alabama Power - Autaugaville	AL	Jan-01	1,260	4	4	"F" Class (170 MW)	NG	CC	8,760	0.035 lb/mmBtu	GCP		
Tenaska Alabama IV Partners	AL	draft permit	1,840	6	6	Mit 501F (170 MW)	NG; FO	CC	8,760; 720 FO	0.088 lb/mmBtu NG (0.115 w/PA & DB); 0.35 lb/mmBtu FO	GCP		SCONOx - $6,145/ton NO_x; CatOx- $1,506/ton CO
Duke Energy Autauga, LLC	AL	applic. under review	630	2	2	GE 7FA (170 MW)	NG	CC	8,760	15 ppm	GCP		SCONOx - $18760/ton NO_x; CatOx- $5,006/ton CO
Kissimmee Utility Authority, Cane Island Power Park -Unit 3	FL	draft permit	250	1	0	GE 7FA (167 MW)	NG; FO	CC	8,760; 720 FO	12 ppm, 20 ppm w/ DB NG; 30 ppm FO	GCP		
Duke Energy - New Smyrna Beach	FL	draft permit	500	2	0	GE 7FA (165 MW)	NG	CC	8,760	12 ppm	GCP		
Lake Worth Generation	FL	Nov-99	244	1	1	GE 7FA (170 MW)	NG; FO	CC	8,760; 1,000 FO	12 ppm NG; 20 ppm FO	GCP		
Hines Energy (FPC)	FL	project dropped	500	2	0	SW 501F (165 MW)	NG; FO	CC	8,760; 1,000 FO	25 ppm NG - full load; 30 ppm FO	GCP		
Gulf Power - Smith Station	FL	Jul-00	340	2	2	GE 7FA (170 MW)	NG	CC	8,760	16 ppm w/ DB, 23 ppm w/ DB & SA	GCP		Netting out of PSD for NO_x and CO; SA = steam augmentation
Florida Power & Light - Sanford	FL	Sep-99	2,200	8	0	GE 7FA (170 MW)	NG, FO	CC	8,760; 500 FO	12 ppm NG; 20 ppm FO	GCP		Repowering, 4 units FO
Gainesville Regional Utilities, Kelly Generating Station	FL	Feb-00	133	1	0	GE 7EA (83 MW)	NG; FO	CC	8,760; 1,000 FO	20 ppm NG; 20 ppm FO	GCP		Netting out of PSD review for NO_x
Calpine Osprey Energy Center	FL	Jul-01	527	2	2	SW 501FD (170 MW)	NG	CC	8,760	10 ppm (17 ppm w/DB or PA)	GCP	24-hr Block	2,800 hr/yr - Power Aug. mode
Hines Energy (FPC)	FL	Jun-01	530	2	0	SW 501FD (170 MW)	NG: FO	CC	8,760; 1,000 FO	16 ppm NG; 30 ppm FO	GCP	24-hr Block	SCONOx - $16,712/ton NO_x; CatOx - $2,130/ton CO
CPV - Gulfcoast	FL	Feb-01	250	1	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	9 ppm NG; 20 ppm FO	GCP		SCONOx - no cost eval.; CatOx - $4,350/ton CO
TECO Gannon/Bayside	FL	Mar-01	1,728	7	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 876 FO	7.2 ppm NG; 14.2 ppm FO	GCP		Repowering project: netting out of NO_x, CO, PM_{10} and SO_2 review (subject to VOC reveiw)
South Pond Energy Park	FL	draft permit	600	3	0	GE 7FA (170 MW)	NG; FO	SC/CC	3,390/8,760; 720 FO	9 ppm NG; 20 ppm FO	GCP		2 SC CT and 1 CC CT also capable of operating in SC mode.

Table B-7. Summary of BACT Determinations for CO for Combined Cycle CTs. 1999-2001

Facility	State	Final Permit Issued	# of New MW	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	CO Limit	Control Method	Avg. Time	Comments
North Pond Energy Park	FL	applic. under review	430	2	0	GE 7FA (170 MW)	NG; FO	SC/CC	3,390/8,760; 720 FO	9 ppm NG; 20 ppm FO	GCP		1 SC CT and 1 CC CT also capable of operating in SC mode.
Calpine Blue Heron Energy Center	FL	draft permit	1,080	4	4	SW 501F (170 MW)	NG	CC	8,760	10/15.6/38.5/50 ppm	GCP		base/duct burner/power aug./60-70% load; SCONOx - \$9,982/ton NO_x; CatOx - \$1,553/ton CO
Jacksonville Electric Authority - Brandy Branch (revision)	FL	draft permit	200	0	2	GE 7FA (170 MW)	NG; FO	CC	8760; 288 FO	12.21/14.17 ppm	GCP		Conversion of 2 SC units to 2 CC units
CPV - Atlantic Power	FL	May-01	250	1	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	9 ppm NG (15 ppm w/PA) ; 20 ppm FO	GCP		PA = Power Augmentation
Orlando Utilities - Curtis H Stanton Energy Center	FL	Sep-01	633	2	2	GE 7FA (170 MW)	NG; FO	CC	8,760; 1000 FO	18.1 ppm NG (26.3 w/PA); 14.3 ppm FO	GCP		
Broward Energy Center	FL	draft permit	775	4	0	GE 7FA (175 MW)	NG	CC/SC	8,760/5,000	8 ppm (SC); 12 ppm (CC w/PA); 8 ppm (CC)	GCP	24-hr	* 1 CC w/unfired HRSG & 3 SC; PA = Power Augmentation
Belle Glade Energy Center	FL	draft permit	600	3	0	GE 7FA (175 MW)	NG	CC/SC	8,760/5,000	8 ppm (SC); 12 ppm (CC w/PA); 8 ppm (CC)	GCP	24-hr	* 1 CC w/unfired HRSG & 2 SC; PA = Power Augmentation
Manatee Energy Center	FL	draft permit	600	3	0	GE 7FA (175 MW)	NG	CC/SC	8,760/5,000	8 ppm (SC); 12 ppm (CC w/PA); 8 ppm (CC)	GCP	24-hr	* 1 CC w/unfired HRSG & 2 SC; PA = Power Augmentation
CPV Pierce Power Generation Facility	FL	Aug-01	250	1	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	8 ppm NG (13 ppm w/PA) ; 17 ppm FO (19 ppm 76-89% load, 26 ppm 50-75% load)	GCP	24-hr	PA limited to 2,000 hr/yr
Fort Pierce Repowering Project	FL	draft permit	180	1	1	SW 501F (180 MW)	NG; FO	CC/SC	8,760; 1,000 FO/2,000; 500 FO	3.5 ppm NG; 10 ppm FO/ 16 ppm NG; 50 ppm FO	GCP		CT will operate in both CC and SC modes
TECO Bayside Power Station	FL	draft permit	1,032	4	0	GE 7FA (170 MW)	NG	CC	8,760	9 ppm (7.8 ppm)	GCP	24-hr (3-hr test)	Repowering Project: Netting out of PSD for NO_x, SO_2, VOC, lead and SAM (subject for PM_{10} and CO)
Georgia Power - Wansley (Oglethorpe Power)	GA	Jul-00	2,280	8	8	GE 7FA (170 MW)	NG	CC	8,760	29.5 ppm/0.066 lb/MMBtu	GCP		
Duke Energy Murray, LLC	GA	Feb-01	1,240	4	4	GE 7FA (170 MW)	NG	CC	8,760	21.8 ppm	GCP		
Duke Energy Buffalo Creek, LLC	GA	applic. under review	620	2	2	GE 7FA (170 MW)	NG	CC	8,760	21.9 ppm	GCP		SCONOx - \$19,948/ton NO_x; CatOx - \$2,469/ton CO
Augusta Energy LLC	GA	draft permit	750	3	3	GE 7FA (170 MW)	NG; FO	CC	8,760; 1,000 FO	17.4 ppm NG; 20 ppm FO	GCP		SCONOx - \$17,490/ton NO_x; CatOx - \$4,133/ton CO
GenPower McIntosh	GA	applic. under review	528	2	2	GE 7FA (170 MW)	NG	CC	8,760	9 ppm/14 (w/DB) ppm	GCP		
Monroe Power Co.	GA	applic. under review	525	2	0	GE 7FA (170 MW)	NG	SC/CC	8,760	9 ppm	GCP		Initially SC, but later converting to CC
Peace Valley Generation Co., LLC	GA	applic. under review	1,550	6	4	F" Class	NG	CC/SC	8,760/2,500	10.6 ppm (25 ppm w/DB)	GCP		
Duke Energy Tift	GA	applic. under review	620	2	2	GE 7FA (170 MW)	NG	CC	8,760	24.1 ppm	GCP		SCONOx - \$16,274/ton NO_x; CatOx - \$2,095/ton CO
CPV Terrapin, LLC	GA	applic. under review	800	3	3	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	9 ppm NG; 13.6 ppm (NG w/DB); 24 ppm FO	GCP	24-hr rolling	
Kinder Morgan Georgia, LLC - Tift Power	GA	applic. under review	560	7	7	1 - GE 7EA & 6 - LM6000	NG	CC	8,760; 3,760 (part load)	158.5 lb/hr & 141.0 lb/hr	GCP		
Hartwell Development Co.	GA	applic. under review	564	2	0	GE 7FA (176 MW)	NG	CC	8,760	7.4 ppm	GCP		SCONOx - \$35,422/ton NO_x; CatOx - \$4,964/ton CO

Table B-7. Summary of BACT Determinations for CO for Combined Cycle CTs. 1999-2001

Facility	State	Final Permit Issued	# of New MW	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	CO Limit	Control Method	Avg. Time	Comments
Kentucky Pioneer Energy	KY	Jun-01	540	2	0	GE 7FA (197 MW)	syngas/ NG	CC	8,760	15/20 ppm	GCP	3-hr	
Duke Energy Hinds, L.L.C.	MS	Apr-00	520	2	0	GE 7FA (170 MW)	NG	CC	8,760	20 ppm	GCP		
Duke Energy Attala, L.L.C.	MS	Apr-00	520	2	0	GE 7FA (170 MW)	NG	CC	8,760	20 ppm	GCP		
Cogentrix Energy, Southaven Power Project	MS	draft permit	800	3	3	GE 7FA (170 MW)	NG	CC	8,760	9 ppm. 18 ppm w/ DB	GCP		
Cogentrix Energy, Caledonia Power Project	MS	Mar-01	800	3	3	GE 7FA (182 MW)	NG	CC	8,760	9 ppm	GCP		revised application to add SCR
GenPower - McAdams LLC	MS	draft permit	528	2	2	GE 7FA (170 MW)	NG	CC	8,760	7-8 ppm/13 ppm (w/DB)	GCP	24-hr	
Lone Oak Energy Center	MS	draft permit	800	3	3	F" Class (180 MW)	NG	CC	8,760	10/25/30/17 ppm	GCP		Base/PA/PA+DF/DF
Lee Power Partners	MS	draft permit	1,000	4	4	F" Class (170 MW)	NG	CC	8,760	25 ppm	GCP		
LSP-Pike Energy LLC	MS	draft permit	1,100	4	4	F" Class (170 MW)	NG	CC	8,760	33.1 ppm (0.15 lb/mmBTU)	GCP		
Magnolia Energy	MS	draft permit	900	3	3	F" Class (170 MW)	NG	CC	8,760	25 ppm	GCP		
Hines Energy Facility	MS	Jan-00	340	2	?	170 MW each	NG	CC	8,760	20 ppm	GCP		
Reliant Energy - Choctaw Co., LLC	MS	draft permit	844	3	3	GE 7FA (170 MW)	NG	CC	8,760	18.36 ppm	GCP		SCONOx - $48,663/ton NO_x; CatOx - $3,550/ton CO
Crossroads Energy Center	MS	applic. under review	580	2	2	GE 7FA (170 MW)	NG	CC	8,760	10.4 ppm	GCP		SCONOx - $23,400/ton NO_x; CatOx - $11,039/ton CO
Choctaw Gas Generation, LLC	MS	applic. under review	700	2	2	SW 501G (250 MW)	NG	CC	8,760	23 ppm	GCP		
Duke Energy Homochitto, LLC	MS	applic. under review	630	2	2	GE 7FA (170 MW)	NG	CC	8,760	20.4 ppm	GCP	24-hr	
Granite Power Partners II (Batesville)	MS	applic. under review	300	1	1	SW 501F (230 MW)	NG	CC	8,760	25 ppm	GCP		
Carolina Power & Light, Richmond Co. (2nd revision - new configuration)	NC	applic. under review	2,040	9	0	GE 7FA (170 MW)	NG; FO	CC/SC	8,760/2,000; 1,000 FO	9 ppm NG; 20 ppm FO	GCP		Reconfiguration of facility: 6 CC and 3 SC CTs
Carolina Power & Light, Rowan Co. (revision)	NC	draft permit	1,110	2	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 1,000 FO	15 ppm NG; 20 ppm FO	GCP		Modification of previous permit to switch 2 SC -> CC
Butler-Warner Generation Plant	NC	applic. under review	500	2	0	GE 7FA (170 MW)	NG; FO	SC & CC	8,760; 500 FO	9 ppm NG; 41 ppm FO	GCP		
GenPower Earleys, LLC	NC	applic. under review	528	2	2	GE 7FA (170 MW)	NG	CC	8,760	9 ppm (14 ppm w/DB)	GCP		SCONOx - $21,942/ton NO_x; CatOx - $3,246ton CO
Santee Cooper, Rainey Generating Station	SC	Apr-00	870	4	0	GE 7FA (170 MW)	NG, FO	2 CC, 2 SC	8,760; 1,000 FO	9 ppm NG; 20 ppm FO	GCP		
SC Electric & Gas - Urquhart	SC	Sep-00	444	2	0	GE 7FA (150 MW)	NG, FO	CC	8,760; 4,380 FO	12 ppm NG; 20 ppm FO	GCP		Netted out of NO_x, SO_2 and PM_{10} PSD Review
Columbia Energy	SC	Apr-01	515	2	2	GE 7FA (170 MW)	NG, FO	CC	8,760; 1,000 FO	17.4 ppm NG; 37 pm FO	GCP		SCONOx - no analysis; CatOx - $1,611/ton CO
GenPower Anderson	SC	draft permit	640	2	2	GE 7FA (170 MW)	NG	CC	8760	11.7 ppm	GCP		
Vanderbilt University	TN	May-00	10	2	2	GE PGT5B (5.2 MW)	NG	CC	8,760	25 ppm	GCP		
Memphis Generation LLC	TN	draft permit	1,050	4	0	GE 7FA (170 MW)	NG	CC	8,760	0.03 lb/mmBtu	GCP		Phase I - 1 CT (up to 7% total plant heat input from refinery fuel gas), Phase II - 3 CTs (up to 2% total plant heat input from refinery fuel gas)

Table B-7. Summary of BACT Determinations for CO for Combined Cycle CTs, 1999-2001

Facility	State	Final Permit Issued	# of New MW	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	CO Limit	Control Method	Avg. Time	Comments
Haywood Energy Center (Calpine)	TN	applic. under review	900	3	3	SW, GE 7FA or GE F7B	NG; FO	CC	8,760	varies from 7.4 to 50 ppm depending on CT type and load	GCP		
TVA - Franklin	TN	applic. under review	610	2	2	GE 7FA (195 MW)		CC	8,760	25 ppm	GCP		

Abbreviations:
GE = General Electric
SW = Seimens Westinghouse
NG = Nat. Gas
FO = Fuel Oil
DB = Duct Burner
SC = Simple Cycle
CC = Combined Cycle
DLN = Dry-Low NOx
WI = Water Injection
SCR = Selective Catalytic Reduction
CatOx = Catalytic Oxidation
GCP = Good Combustion Practices

Source: http://www.epa.gov/region4/air/permits/national_ct_list.xls (2001)

Table B-8. Direct and Indirect Capital Costs for CO Catalyst, GE Frame 7FA in Combined Cycle Combustion Turbine

Cost Component	Costs	Basis of Cost Component
Direct Capital Costs		
CO Associated Equipment	$758,000	Vendor Quote
Flue Gas Ductwork	$44,505	Vatavauk,1990
Instrumentation	$75,800	10% of SCR Associated Equipment
Sales Tax	$45,480	6% of SCR Associated Equipment/Catalyst
Freight	$37,900	5% of SCR Associated Equipment/Catalyst
Total Direct Capital Costs (TDCC)	$961,685	
Direct Installation Costs		
Foundation and supports	$76,935	8% of TDCC and RCC;OAQPS Cost Control Manual
Handling & Erection	$134,636	14% of TDCC and RCC;OAQPS Cost Control Manual
Electrical	$38,467	4% of TDCC and RCC;OAQPS Cost Control Manual
Piping	$19,234	2% of TDCC and RCC;OAQPS Cost Control Manual
Insulation for ductwork	$9,617	1% of TDCC and RCC;OAQPS Cost Control Manual
Painting	$9,617	1% of TDCC and RCC;OAQPS Cost Control Manual
Site Preparation	$5,000	Engineering Estimate
Buildings	$0	
Total Direct Installation Costs (TDIC)	$293,506	
Total Capital Costs	$1,255,191	Sum of TDCC, TDIC and RCC
Indirect Costs		
Engineering	$125,519	10% of Total Capital Costs; OAQPS Cost Control Manual
Construction and Field Expense	$62,760	5% of Total Capital Costs; OAQPS Cost Control Manual
Contractor Fees	$125,519	10% of Total Capital Costs; OAQPS Cost Control Manual
Start-up	$25,104	2% of Total Capital Costs; OAQPS Cost Control Manual
Performance Tests	$12,552	1% of Total Capital Costs; OAQPS Cost Control Manual
Contingencies	$37,656	3% of Total Capital Costs; OAQPS Cost Control Manual
Total Indirect Capital Cost (TInDC)	$389,109	
Total Direct, Indirect and Capital Costs (TDICC)	$1,644,300	Sum of TCC and TInCC

Table B-9. Annualized Cost for CO Catalyst GE Frame 7FA in Combined Cycle Combustion Turbine

Cost Component	Cost	Basis of Cost Estimate
Diirect Annual Costs		
Operating Personnel	$6,240	8 hours/week at $15/hr
Supervision	$936	15% of Operating Personnel;OAQPS Cost Control Manual
Catalyst Replacement	$219,667	3 year catalyst life; base on Vendor Budget Quote
Inventory Cost	$24,668	Capital Recovery (10.98%) for 1/3 catalyst
Contingency	$7,545	3% of Direct Annual Costs
Total Direct Annual Costs (TDAC)	$259,056	
Energy Costs		
Heat Rate Penalty	$214,208	0.2% of MW output; EPA, 1993 (Page 6-20) and $3/mmBtu addl fuel costs
Total Energy Costs (TDEC)	$214,208	
Indirect Annual Costs		
Overhead	$4,306	60% of Operating/Supervision Labor
Property Taxes	$16,443	1% of Total Capital Costs
Insurance	$16,443	1% of Total Capital Costs
Annualized Total Direct Capital	$180,544	10.98% Capital Recovery Factor of 7% over 15 yrs times sum of TDICC
Total Indirect Annual Costs	$217,736	
Total Annualized Costs	$691,000	Sum of TDAC, TEC and TIAC
Cost Effectiveness	$4,165	per ton of CO Removed
	$4,594	per ton of Net Emission Reduction

Table B-10. Comparison of Alternative BACT Control Technologies with Installing OC in HRSG

	Alternative BACT Control Technologies	
	DLN/WI Only	DLN/WI with OC
Technical Assessment	Feasible	Available, Feasible and Demonstrated
Economic Impact [a]		
Capital Costs	included	$1,644,300
Annualized Costs	included	$691,000
Cost Effectiveness		
CO Removed (per ton of CO)	NA	$4,165
Environmental Impact [b]		
Total CO (TPY)	193	27
CO Reduction (TPY)	NA	-165
Net Pollutant Reduction	NA	-150
Additional Greenhouse Gas (CO2; tons/yr)	--	1,971
Energy Impacts [c]		
Energy Use (kWh/yr)	0	3,021,149
Energy Use (Equivalent Residential Customers/year)	0	252
Energy Use (mmBtu/yr) at 10,000 Btu/kWh	0	31,121
Energy Use (mmcf/yr) at 1,000 Btu/cf for natural gas	0	31

[a] See Tables B-8 and B-9 for detailed development of capital costs (including recurring costs) and annualized costs.

[b] See emission data presented in Table B-11.

[c] Energy impacts are estimated due to the lost energy from heat rate penalty for 8,760 hours per year. Lost energy is based on 0.2 percent of 166 MW.

Table B-11. Maximum Potential Incremental Emissions (TPY) with Oxidation Catalyst

		Incremental Emissions (tons/year) of SCR		
Pollutants		Primary	Secondary	Total
Particulate		11.92	0.11	12.04
Sulfur Dioxide			0.04	0.04
Nitrogen Oxides		0.00	2.07	2.07
Carbon Monoxide		-165.9	1.24	-164.7
Volatile Organic Compounds			0.08	0.08
	Total:	-154.0	3.56	-150.4
Carbon Dioxide (additional from gas firing)			1,971.0	1,971.0

Basis:

Lost Energy (mmBtu/year) 31,121

Secondary Emissions (lb/mmBtu): Assumes natural gas firing in NOx controlled steam unit.

Particulate	0.0072
Sulfur Dioxide	0.0027
Nitrogen Oxides w/LNB	0.1333
Carbon Monoxide	0.0800
Volatile Organic Compounds	0.0052

Reference: Table 1.4-1 and 1.4-2, AP-42, Version 2/98

APPENDIX C

CALPUFF MODEL DESCRIPTION AND METHODOLOGY

CALPUFF MODEL DESCRIPTION AND METHODOLOGY

C.1 INTRODUCTION

As part of the new source review requirements under Prevention of Significant Deterioration (PSD) regulations, new sources are required to address air quality impacts at PSD Class I areas. As part of the PSD analysis report submitted to the Florida Department of Environmental Protection (DEP), the air quality impacts due to the potential emissions of the proposed FPL Martin project are required to be addressed at the PSD Class I area of the Everglades National Park (ENP). The ENP is located approximately 144 km south of the facility site and is the only PSD Class I area within 200 km of the facility.

The evaluation of air quality impacts are not only concerned with determining compliance with PSD Class I increments but also assessing a source's impact on Air Quality Related Values (AQRVs), such as regional haze. Further, compliance with PSD Class I increments can be evaluated by determining if the source's impacts are less than the proposed U.S. Environmental Protection Agency (EPA) Class I significant impact levels. The significant impact levels are threshold levels that are used to determine the type of air impact analyses needed for the facility. If the new source's impacts are predicted to be less than significant, then the source's impacts are assumed not to have a significant adverse affect on air quality and additional modeling with other sources is not required. However, if the source's impacts are predicted to be greater than the significant impact levels, additional modeling with other sources is required to demonstrate compliance with Class I increments.

Currently there are several air quality modeling approaches recommended by the Interagency Workgroup on Air Quality Models (IWAQM) to perform these analyses. The IWAQM consists of EPA and Federal Land Managers (FLM) of Class I areas who are responsible for ensuring that AQRVs are not adversely impacted by new and existing sources. These recommendations have been summarized in two documents:

! *Interagency Workgroup on Air Quality Models (IWAQM), Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts* (EPA, 1998), referred to as the IWAQM Phase 2 report.

! *Federal Land Managers' Air Quality Related Values Workgroup (FLAG), Phase I Report,* USFS, NPS, USFWS (12/00), referred to as the FLAG document.

For the proposed project, air quality analyses were performed that assess the facility's impacts in the PSD Class I area of the ENP using the refined modeling approach from the IWAQM Phase 2 report for:

- Significant impact analysis.
- SO_2 PSD Class I increment analysis; and
- Regional haze analysis

The refined analysis approach was used instead of the screening analysis approach since the air quality impacts are based on generally more realistic assumptions, include more detailed meteorological data, and are estimated at locations at the Class I area.

C.2 GENERAL AIR MODELING APPROACH

The general modeling approach was based on using the long-range transport model, California Puff model (CALPUFF, Version 5.4). At distances beyond 50 km, the ISCST3 model is considered to over-predict air quality impacts, because it is a steady-state model. At those distances, the CALPUFF model is recommended for use. Recently, the FLM have requested that air quality impacts, such as for regional haze, for a source located more than 50 km from a Class I area be predicted using the CALPUFF model. The Florida DEP has also recommended that the CALPUFF model be used to assess if the source has a significant impact at a Class I area located beyond 50 km from the source. As a result, a significant impact and regional haze analyses were performed using the CALPUFF model to assess the facility's impacts at the ENP.

The methods and assumptions used in the CALPUFF model were based on the latest recommendations for a refined analysis as presented in the IWAQM Phase 2 Summary Report and the FLAG documents.

A regional haze analysis was performed to determine the affect that the facility's emissions will have on background regional haze levels at the ENP. In the regional haze analysis, the change in visual range, as calculated by a deciview change, was estimated for the facility in accordance with the IWAQM recommendations. Based on those recommendations, the CALPUFF model is used to predict the maximum 24-hour average sulfate (SO_4), nitrate (NO_3), and fine particulate (PM_{10}) concentrations as well as ammonium sulfate [$(NH_4)_2SO_4$] and ammonium nitrate (NH_4NO_3) concentrations. The change in visibility due to a source, estimated as a percentage, is then calculated based on the change from background data.

The following sections present the methods and assumptions used to assess the refined significant impact and regional haze analyses performed for the Proposed Project. The results of these analyses are presented in Sections 6.0 and 7.0 of the PSD report.

C.3 MODEL SELECTION AND SETTINGS

The California Puff (CALPUFF, version 5.4) air modeling system was used to model to assess the Proposed Project's impacts at the PSD Class I area for comparison to the PSD Class I significant impact levels and to the regional haze visibility criteria. 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 CALPUFF meteorological and geophysical data preprocessor (CALMET, Version 5.2), 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. 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 and FLAG reports.

C.3.1 CALPUFF MODEL APPROACHES AND SETTINGS

The IWAQM has recommended approaches for performing a Phase 2 refined modeling analyses that are presented in Table 1. These approaches involve use of meteorological data, selection of receptors and dispersion conditions, and processing of model output.

The specific settings used in the CALPUFF model are presented in Table 2.

C.3.2 EMISSION INVENTORY AND BUILDING WAKE EFFECTS

The CALPUFF model included the facility's emission, stack, and operating data as well as 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 PSD Analysis Report presents a listing of the facility's emissions and structures included in the analysis.

C.4 RECEPTOR LOCATIONS

For the refined analyses, pollutant concentrations were predicted in an array of 126 discrete receptors located at the ENP area. These receptors are the same as those used in the PSD Class I analysis performed for the PSD Analysis Report.

C.5 METEOROLOGICAL DATA

C.5.1 REFINED ANALYSIS

CALMET was used to develop the gridded parameter fields required for the refined modeling analyses. The follow sections discuss the specific data used and processed in the CALMET model.

C.5.2 CALMET SETTINGS

The CALMET settings contained in Table 3 were used for the refined modeling analysis. With the exception of hourly precipitation data files, all input data files needed for CALMET were developed by the FDEP staff.

C.5.3 MODELING DOMAIN

A rectangular modeling domain extending 450 km in the east-west (x) direction and 470 km in the north-south (y) direction was used for the refined modeling analysis. The southwest corner of the domain is the origin and is located at 23.8 degrees north latitude and 83.5 degrees west longitude. This location is in the Gulf of Mexico approximately 110 km west of Venice, Florida. For the processing of meteorological and geophysical data, the domain contains 90 grid cells in the x-direction and 94 grid cells in the y-direction. The domain grid resolution is 5 km. The air modeling analysis was performed in the UTM coordinate system.

C.5.4 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.

The MM4 subset domain was provided by FDEP and consisted of a 7 x 7- cell rectangle, with 80 km grid resolution, extending from the MM4 grid points (50,6) to (57,13). These data were processed to create a MM4.DAT file, for input to the CALMET model.

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.

C.5.5 SURFACE DATA STATIONS AND PROCESSING

The surface station data processed for the CALPUFF analyses consisted of data from eight NWS stations or Federal Aviation Administration (FAA) Flight Service stations for Orlando, Fort Myers, Daytona Beach, Vero Beach, Key West, Miami, Tampa, and West Palm Beach. A summary of the surface station information and locations are presented in Table 4. 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 surface station data were processed by FDEP into a SURF.DAT file format for CALMET input.

Because the modeling domain extends largely over water, C-Man station data from Venice, Sombrero Key, and Lake Worth was obtained. These data were processed by Florida DEP into an over-water surface station format (i.e., SEA*.DAT) for input to CALMET. The over-water station data include wind direction, wind speed and air temperature.

C.5.6 UPPER AIR DATA STATIONS AND PROCESSING

The analysis included three upper air NWS stations located in Ruskin, Key West, and West Palm Beach. Data for each station were obtained from the Florida DEP in a format for CALMET input. The data and locations for the upper air stations are presented in Table 4.

C.5.7 PRECIPITATION DATA STATIONS AND PROCESSING

Precipitation data were processed from a network of hourly precipitation data files collected from primary and secondary NWS precipitation-recording stations located within the latitude and longitudinal limits of the modeling domain. Data for 23 stations were obtained in NCDC TD-3240 variable format and converted into a fixed-length format. The utility programs PXTRACT and PMERGE were then 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 5.

C.5.8 GEOPHYSICAL DATA PROCESSING

Terrain elevations for each grid cell of the modeling domain were obtained from 1-degree Digital Elevation Model (DEM) files obtained from the U.S. Geographical Survey (USGS) internet website. The DEM data was extracted for the modeling domain grid using the utility program TERREL. Land-use data were also extracted from 1-degree USGS files and processed using utility programs CTGCOMP and CTGPROC. Both the terrain and land use files were combined into a GEO.DAT file for input to CALMET with the MAKEGEO utility program.

Table 1. Refined Modeling Analyses Recommendations [a]

Model Input/Output	Description
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	1. For PSD increments: use highest, second highest 3-hour and 24-hour average SO_2 concentrations; highest, second highest 24-hour average PM_{10} concentrations; and highest annual average SO_2, PM_{10} and NO_x concentrations. 2. For haze: process, on a 24-hour basis, compute the source extinction from the maximum increase in emissions of SO_2, NO_x and PM_{10}; compute the daily relative humidity factor [f(RH)], provided from an external disk file; and compute the maximum percent change in extinction using the FLM supplied background extinction data in the FLAG document. 3. For significant impact analysis: use highest annual and highest short-term averaging time concentrations for SO_2, PM_{10} and NO_x.

[a] IWAQM Phase II report (December, 1998) and FLAG document (December, 2000)

Table 2. CALPUFF Model Settings

Parameter	Setting
Pollutant Species	SO_2, SO_4, NO_x, HNO_3, NO_3, PM_{10}
Chemical Transformation	MESOPUFF II scheme, hourly ozone data
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, PM_{10}, SO_2, and NO_x; process for visibility change using Method 2 and FLAG background extinctions
Model Processing	For haze: highest predicted 24-hour extinction change (%) for the year For deposition: annual average deposition rate For significant impact analysis: highest predicted annual and highest short-term averaging time concentrations for SO_2, NO_x, and PM_{10}.
Background Values	Ozone: 80 ppb; Ammonia: 1 ppb

[a] Recommended values by the Florida DEP.

Table 3. CALMET Settings

Parameter	Setting
Horizontal Grid Dimensions	450 by 470 km, 5 km grid resolution
Vertical Grid	9 layers
Weather Station Data Inputs	8 surface, 3 upper air, 23 precipitation stations
Wind model options	Diagnostic wind model, no kinematic effects
Prognostic wind field model	MM4 data, 80 km resolution, 7 x 7 grid, used for wind field initialization
Output	Binary hourly gridded meteorological data file for CALPUFF input

Table 4. Surface and Upper Air Stations Used in the CALPUFF Analysis

Station Name	Station Symbol	WBAN Number	UTM Coordinates Easting (km)	Northing (km)	Zone	Anemometer Height (m)
Surface Stations						
Tampa	TPA	12842	349.20	3094.25	17	6.7
Daytona Beach	DAB	12834	495.14	3228.05	17	9.1
Orlando	ORL	12815	468.96	3146.88	17	10.1
Vero Beach	VER	12843	557.52	3058.36	17	6.7
Fort Myers	FMY	12835	413.65	2940.38	17	6.1
Miami	MIA	12839	566.82	2857.20	17	7.0
Key West	EYW	12836	424.03	2715.14	17	18.3
West Palm Beach	PBI	12844	587.87	2951.43	17	10.1
Upper Air Stations						
Ruskin	TBW	12842	349.20	3094.28	17	NA
West Palm Beach	PBI	12844	587.87	2951.42	17	NA
Key West	EYW	12836	424.03	2715.14	17	NA

Table 5. Hourly Precipitation Stations Used in the CALPUFF Analysis

Station Name	Station Number	UTM Coordinate Easting (km)	UTM Coordinate Northing (km)	Zone
Belle Glade HRCN GT 4	80616	528.19	2953.03	17
Boca Raton	80845	588.75	2916.52	17
Canal Point Gate 5	81271	536.43	2971.51	17
Clewiston US Engineers	81654	546.19	2912.73	17
Fort Myers FAA/AP	83186	413.99	2940.71	17
Homestead Exp Stn	84091	550.26	2820.21	17
Key West Intl AP	84570	423.67	2715.51	17
Miami WSCMO Airport	85663	570.20	2856.17	17
Moore Haven Lock 1	85895	491.61	2967.80	17
North New River Canal #	86323	546.58	2912.48	17
Ortona Lock 2	86657	470.17	2962.27	17
Parrish	86880	366.99	3054.39	17
Pennsuco 5 WNW	86988	554.70	2867.81	17
Port Mayaca S l Canal	87293	538.04	2984.44	17
St Lucie New Lock 1	87859	571.04	2999.35	17
St Petersburg	87886	339.61	3071.99	17
Tamiami Trail 40 Mi BEN	88780	517.64	2849.04	17
Tampa WSCMO AP	88788	348.48	3093.67	17
Trail Glade Ranges	89010	551.57	2849.99	17
Venice	89176	357.59	2998.18	17
Venus	89184	467.27	3001.22	17
Vero Beach 4 W	89219	554.27	3056.50	17
West Palm Beach Int AP	89525	589.61	2951.63	17

APPENDIX D

SO_2 EMISSION DATA FOR BACKGROUND SOURCES

Table D-1. Summary of SO_2 Sources Included in the Air Modeling Analysis

AIRS Number	Facility Units	Modeling ID Name	Relative Location X (km)	Relative Location Y (km)	Stack and Operating Parameters Height (m)	Diameter (m)	Temper. (K)	Velocity (m/s)	Emission Rate(g/s) 24-Hour	PSD Source? (EXP/CON)	Modeled in AAQS	Class II	Class I
0850001	FPL Martin												
	Units 1&2	MART12	-0.168	0.601	152.1	7.99	420.9	21.03	1743.79	NO	Yes	No	No
	Aux Blr PSD	MARTAUX	-0.046	0.162	18.3	1.10	535.4	15.24	12.90	CON	Yes	Yes	Yes
	Diesel Gens PSD	MARTGEN	-0.046	0.162	7.6	0.30	785.9	39.62	0.51	CON	Yes	Yes	Yes
	Units 3&4 PSD	MART34	-0.046	0.162	64.9	6.10	410.9	18.90	470.40	CON	Yes	Yes	Yes
0850102	Bechtel Indiantown PSD	BECHTIND	2.5	-1.4	150.9	4.88	333.2	30.50	75.64	CON	Yes	Yes	Yes
990021	Pratt & Whitney												
	Heater	PRATARCH	16.1	-14.6	15.2	0.91	810.9	143.73	13.99	CON	Yes	Yes	Yes
	Boiler BO-12	PRATBO12	16.1	-14.6	4.6	0.76	533.2	6.92	0.51	CON	Yes	Yes	Yes
0990019	Osceola Farms [a]												
	Unit 2	OSBLR2	1.1	-24.9	27.4	1.52	339.0	18.63	17.12	CON	Yes	Yes	Yes
	Unit 3	OSBLR3	1.1	-24.9	27.4	1.92	344.0	14.34	30.74	CON	Yes	Yes	Yes
	Unit 4	OSBLR4	1.1	-24.9	27.4	1.83	344.0	16.53	17.12	CON	Yes	Yes	Yes
	Unit 5	OSBLR5	1.1	-24.9	27.4	1.52	344.0	17.85	18.00	CON	Yes	Yes	Yes
	Unit 6	OSBLR6	1.1	-24.9	27.4	1.92	339.0	18.25	33.39	CON	Yes	Yes	Yes
	Unit 1 PSD Baseline	OSBLR1B	1.1	-24.9	22.0	1.52	342.0	8.18	-5.07	EXP	No	Yes	Yes
	Unit 2 PSD Baseline	OSBLR2B	1.1	-24.9	22.0	1.52	341.0	18.10	-16.32	EXP	No	Yes	Yes
	Unit 3 PSD Baseline	OSBLR3B	1.1	-24.9	22.0	1.93	341.0	14.50	-7.26	EXP	No	Yes	Yes
	Unit 4 PSD Baseline	OSBLR4B	1.1	-24.9	22.0	1.83	341.0	18.80	-13.61	EXP	No	Yes	Yes
0990061	US Sugar-Bryant [a]												
	Unit 5 PSD	USSBRY5	-4.3	-24.8	42.7	2.90	345.0	11.49	45.70	CON	Yes	Yes	Yes
	Unit 1,2&3	USBRY123	-4.3	-24.8	19.8	1.64	342.0	36.40	109.50	CON	Yes	Yes	Yes
	Unit 1 PSD Baseline	USSBRY1B	-4.3	-24.8	19.8	1.68	494.0	44.30	-36.50	EXP	No	Yes	Yes
	Unit 2&3 PSD Baseline	USBRY23B	-4.3	-24.8	19.8	1.68	344.0	37.90	-73.00	EXP	No	Yes	Yes
0990026	Sugar Cane Growers [a]												
	Unit 1&2	SUGCN12	-8.2	-39.6	45.7	1.87	339.0	21.75	41.20	CON	Yes	Yes	Yes
	Unit 3	SUGCN3	-8.2	-39.6	27.4	1.52	339.0	22.25	16.20	CON	Yes	Yes	Yes
	Unit 4 PSD	SUGCN4	-8.2	-39.6	54.9	2.44	339.0	21.73	38.20	CON	Yes	Yes	Yes
	Unit 5	SUGCN5	-8.2	-39.6	45.7	2.30	339.0	15.94	27.90	CON	Yes	Yes	Yes
	Unit 8 PSD	SUGCN8	-8.2	-39.6	47.2	2.90	339.0	13.62	23.50	CON	Yes	Yes	Yes
	Unit 1&2 PSD Baseline	SUGCN12B	-8.2	-39.6	24.4	1.40	344.0	11.40	-24.20	EXP	No	Yes	Yes
	Unit 3 PSD Baseline	SUGCN3B	-8.2	-39.6	24.4	1.60	344.0	15.60	-4.40	EXP	No	Yes	Yes
	Unit 4 PSD Baseline	SUGCN4B	-8.2	-39.6	25.9	1.63	344.0	11.20	-24.20	EXP	No	Yes	Yes
	Unit 5 PSD Baseline	SUGCN5B	-8.2	-39.6	24.4	1.40	344.0	15.20	-16.20	EXP	No	Yes	Yes
	Unit 6&7 PSD Baseline	SUGCN67B	-8.2	-39.6	12.2	1.52	606.0	11.20	-51.00	EXP	No	Yes	Yes
0990016	Atlantic Sugar [a]												
	Unit 1	ATLSUG1	9.8	-47.7	27.4	1.83	346.0	17.97	16.28	CON	Yes	Yes	Yes
	Unit 2	ATLSUG2	9.8	-47.7	27.4	1.83	350.0	23.36	16.28	CON	Yes	Yes	Yes
	Unit 3	ATLSUG3	9.8	-47.7	27.4	1.83	350.0	21.56	16.02	CON	Yes	Yes	Yes
	Unit 4	ATLSUG4	9.8	-47.7	27.4	1.83	344.0	25.16	16.21	CON	Yes	Yes	Yes
	Unit 5 PSD [b]	ATLSUG5	9.8	-47.7	27.4	1.68	339.0	19.24	8.04	CON	Yes	Yes	Yes
	Unit 1 PSD Baseline	ATLSUG1B	9.8	-47.7	18.9	1.92	506.0	12.70	-17.24	EXP	No	Yes	Yes
	Unit 2 PSD Baseline	ATLSUG2B	9.8	-47.7	18.9	1.92	511.0	10.90	-22.50	EXP	No	Yes	Yes
	Unit 3 PSD Baseline	ATLSUG3B	9.8	-47.7	21.9	1.83	522.0	17.50	-16.88	EXP	No	Yes	Yes
	Unit 4 PSD Baseline	ATLSUG4B	9.8	-47.7	18.3	1.83	344.0	15.00	-10.76	EXP	No	Yes	Yes
	Fort Pierce Utilities												
	Units 6&7	FTPIER67	23.7	43.4	45.7	2.19	408.2	12.50	77.87	NO	Yes	No	No
0510001	Everglades Sugar [b] Main Boiler	EVERGLAD	-33.5	-38.7	21.9	1.10	477.0	10.10	34.90	NO	Yes	No	No

Table D-1. Summary of SO_2 Sources Included in the Air Modeling Analysis

AIRS Number	Facility	Units	Modeling ID Name	Relative Location X (km)	Relative Location Y (km)	Stack and Operating Parameters Height (m)	Diameter (m)	Temper. (K)	Velocity (m/s)	Emission Rate(g/s) 24-Hour	PSD Source? (EXP/CON)	Modeled in AAQS	Class II	Class I
0510003	US Sugar - Clewiston[d]													
		PSD Baseline (On-crop season only)												
		Unit 1 PSD Baseline	USSBRL1B	-37	-36	23.1	1.86	344.0	30.20	-58.21	EXP	No	Yes	Yes
		Unit 2 PSD Baseline	USSBLR2B	-37	-36	23.1	1.86	343.0	35.70	-58.21	EXP	No	Yes	Yes
		Unit 3 PSD Baseline	USSBLR3B	-37	-36	27.4	2.29	342.0	14.70	-33.20	EXP	No	Yes	Yes
		East Pellet Plant PSD Baseline	EPELLET	-37	-36	12.2	1.52	347.0	8.54	-10.30	EXP	No	Yes	Yes
		West Pellet Plant PSD Baseline	WPELLET	-37	-36	15.7	1.52	347.0	8.54	-10.30	EXP	No	Yes	Yes
		On-crop season future												
		Unit 1	USSBRL1N	-37	-36	65.0	2.44	347.0	15.36	73.73	CON	Yes	Yes	Yes
		Unit 2	USSBLR2N	-37	-36	65.0	2.44	338.0	13.86	73.44	CON	Yes	Yes	Yes
		Unit 3	USSBLR3N	-37	-36	65.0	2.44	333.2	6.78	47.08	CON	Yes	Yes	Yes
		Unit 4	USSBLR4N	-37	-36	45.7	2.51	344.3	20.28	3.68	CON	Yes	Yes	Yes
		Unit 7	USSBLR7N	-37	-36	68.6	2.59	405.4	20.77	12.65	CON	Yes	Yes	Yes
		Off-crop season future												
		Unit 1	USSBRL1F	-37	-36	65.0	2.44	347.0	14.05	24.29	CON	Yes	Yes	Yes
		Unit 2	USSBLR2F	-37	-36	65.0	2.44	338.0	12.68	24.02	CON	Yes	Yes	Yes
		Unit 3	USSBLR3F	-37	-36	65.0	2.44	333.2	6.20	30.20	CON	Yes	Yes	Yes
		Unit 4	USSBLR4F	-37	-36	45.7	2.51	344.3	0.00	0.00	CON	Yes	Yes	Yes
		Unit 7	USSBLR7F	-37	-36	68.6	2.59	405.4	23.60	15.81	CON	Yes	Yes	Yes
0990234	Palm Beach Co. Resource Recovery													
		1&2 PSD	PBCRRF	42.7	-32.7	76.2	2.04	505.2	24.90	85.05	CON	Yes	Yes	Yes
0990042	FPL Riviera[c]													
		Units 3&4 at 2.5%s fuel oil	RIVU34	51.1	-32.3	90.8	4.88	401.5	18.90	2113.65	NO	Yes	No	No
	Vero Beach Power[c]													
		Unit 1	VERBU1	24	63.6	60.96	1.07	437.0	32.42	28.77	NO	Yes	No	No
		Unit 2	VERBU2	24	63.6	60.96	1.07	434.3	37.57	84.21	NO	Yes	No	No
		Unit 3	VERBU3	24	63.6	60.96	1.83	440.4	19.93	142.07	NO	Yes	No	No
		Unit 4	VERBU4	24	63.6	60.96	2.13	425.4	24.36	69.05	NO	Yes	No	No
		Unit 5 Simple Cycle CT	VERBU5	24	63.6	38.10	3.35	416.5	19.56	15.50	CON	Yes	Yes	No
0990568	Lake Worth Utilities[c]													
		Unit 3	LAKWTHU3	49.7	-49.2	38.1	2.13	408.2	7.71	103.95	NO	Yes	No	No
		Unit 4	LAKWTHU4	49.7	-49.2	35.1	2.29	418.2	17.00	129.85	NO	Yes	No	No
		Unit 5	LAKWTHU5	49.7	-49.2	22.9	0.94	450.4	18.29	11.59	NO	Yes	No	No
		HRSG	LAKWTHHR	49.7	-49.2	45.7	5.49	377.6	13.74	12.79	CON	Yes	Yes	Yes
0250348	Dade County RRF PSD													
		Units 1&2	DCRRF12	21.2	-135.5	76.2	3.66	405.4	15.86	12.32	CON	No[e]	No[e]	Yes
		Units 3&4	DCRRF34	21.2	-135.5	76.2	3.66	405.4	15.86	12.32	CON	No[e]	No[e]	Yes
0250020	Tarmac													
		Kiln 1	TARMC1	19.8	-131.2	61.0	2.44	465.0	12.80	5.67	NO	No[e]	No[e]	No
		Kiln 2 PSD Baseline	TARMC2B	19.8	-131.2	61.0	2.44	465.0	12.84	-5.71	EXP	No[e]	No[e]	Yes
		Kiln 3 PSD Baseline	TARMC3B	19.8	-131.2	61.0	4.57	472.0	10.78	-2.76	EXP	No[e]	No[e]	Yes
		Kiln 2 PSD	TABMC2P	19.8	-131.2	61.0	2.44	422.0	9.10	24.57	CON	No[e]	No[e]	Yes
		Kiln 3 PSD	TARMC3P	19.8	-131.2	61.0	4.57	450.0	11.04	51.43	CON	No[e]	No[e]	Yes
0112119	South Broward RRF PSD		SBCRRF	36.5	-109.6	59.4	3.96	381.0	18.01	37.91	CON	No[e]	No[e]	Yes

Table D-1. Summary of SO_2 Sources Included in the Air Modeling Analysis

AIRS Number	Facility Units	Modeling ID Name	Relative Location X (km)	Relative Location Y (km)	Stack and Operating Parameters Height (m)	Diameter (m)	Temper. (K)	Velocity (m/s)	Emission Rate(g/s) 24-Hour	PSD Source? (EXP/CON)	Modeled in AAQS	Modeled in Class II	Modeled in Class I
0110037	FPL - Lauderdale												
	CTs 1-4 PSD	LAUDU45	37	-109.6	45.7	5.49	438.7	14.60	271.15	CON	No [e]	No [e]	Yes
	GT 1-12 (0.5% fuel oil)	LDGT1_12	37	-109.6	13.7	2.37	733.2	114.31	552.80	NO	No [e]	No [e]	No
	GT 13-24 (0.5% fuel oil)	LDGT1324	37	-109.6	13.4	4.75	733.2	28.43	552.80	NO	No [e]	No [e]	No
	4&5 PSD Baseline	FTLAU45B	37	-109.6	46.0	4.27	422.0	14.63	-457.00	EXP	No [e]	No [e]	Yes
110120	North Broward RRF PSD	NBCRRF	40.5	-85.3	58.5	3.96	381.0	18.01	35.40	CON	No [e]	No [e]	Yes
0710019	Lee County RRF PSD	LEECORRF	44.3	-107.6	83.8	1.88	388.5	19.81	14.00	CON	No [e]	No [e]	Yes
50PMB500332	Okeelanta [a]												
	Boiler 4 PSD Baseline	OKBLR4B	-18.1	-55.5	22.9	2.29	333.0	7.36	-10.95	EXP	No [e]	No [e]	Yes
	Boiler 5 PSD Baseline	OKBLR5B	-18.1	-55.5	22.9	2.29	333.0	12.07	-15.64	EXP	No [e]	No [e]	Yes
	Boiler 6 PSD Baseline	OKBLR6B	-18.1	-55.5	22.9	2.29	334.0	8.74	-15.64	EXP	No [e]	No [e]	Yes
	Boiler 10 PSD Baseline	OKBLR10B	-18.1	-55.5	22.9	2.29	334.0	10.35	-17.15	EXP	No [e]	No [e]	Yes
	Boiler 11 PSD Baseline	OKBLR11B	-18.1	-55.5	22.9	2.29	342.0	9.89	-16.79	EXP	No [e]	No [e]	Yes
	Boiler 16 PSD	OKBLR16	-18.1	-55.5	22.9	1.52	483.0	22.86	-1.47	CON	No [e]	No [e]	Yes
	Okeelanta Power Blrs 1,2,3 [b]	OKCOGENF	-18.1	-55.5	60.7	3.05	450.9	19..39	54.1	CON	No [e]	No [e]	Yes
0710000	FPL Fort Myers												
	Unit 1 PSD	FMU1	-121	-40	91.8	2.90	422.0	29.90	-585.50	EXP	No [e]	No [e]	Yes
	Unit 2 PSD	FMU2	-121	-40	121.2	5.52	408.0	19.20	-1334.0	EXP	No [e]	No [e]	Yes
	HRSGs 1 - 6	FMYHR1_6	-121	-40	38.1	5.79	377.6	14.2	3.9	CON	No [e]	No [e]	Yes
	Gas Turbines 1 -12	FMYGT112	-121	-40	9.75	4.42	797.0	35.7	649.2	NO	No [e]	No [e]	No
50FTM260015	Southern Gardens Citrus - PSD												
	Peel Dryer	SGARDDRY	-55.5	-35.3	38.1	1.73	316.0	7.45	5.29	CON	No [e]	No [e]	Yes
	Boilers 1-3	SGARDBLR	-55.5	-35.3	16.8	1.22	478.0	14.22	6.88	CON	No [e]	No [e]	Yes

Note: EXP = PSD expanding source
CON = PSD consuming source
NO = Source does not affect PSD increment

[a] Facilities or sources within facilities that operate only during the October 1 through April 31 crop season.

[b] Sugar mill sources that operate all year.

[c] Large source with emissions greater than 1,000 TPY included in the AAQS or PSD Class II modeling even though the source is located outside of the screening area.

[d] Represents worst case emissions for May 1 through September 31 off-crop season operation, and October 1-April 30 for on-crop season.
Updated from PSD modeling information, Golder Associates (7/18/00). Baseline data represents November 1 though April 30.

[e] Not included in the AAQS or PSD Class II modeling because these sources were screened out using the North Carolina Screening Technique or located more than 100 km from the modeling area.

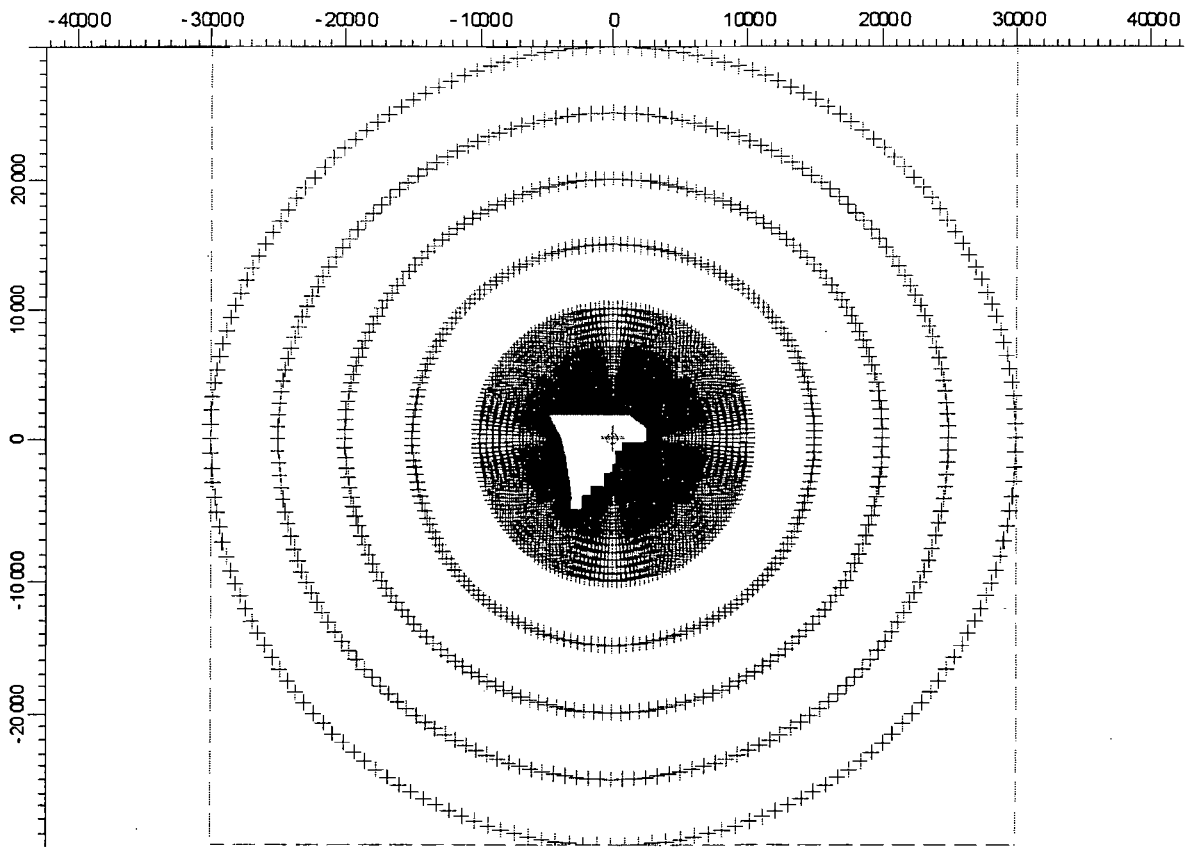
APPENDIX E

RECEPTOR LOCATION FIGURES AND BUILDING PROFILE INPUT PROGRAM (BPIP) FILES

GENERIC MAXIMUM IMPACT RECEPTOR GRID

PROJECT TITLE :

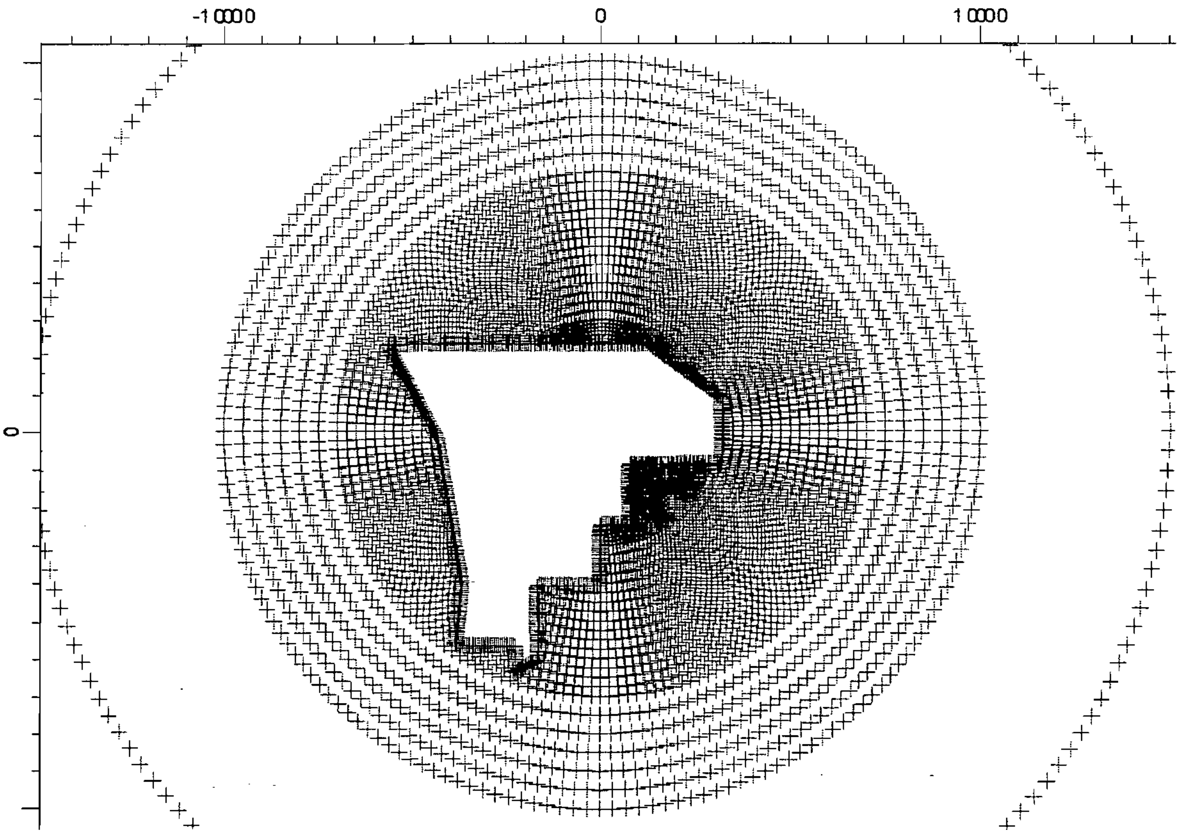
Maximum Impact Receptor Grid



COMMENTS :	SOURCES : 6	COMPANY NAME : **Golder Associates, Inc.**	
	RECEPTORS : 5526	MODELER : **Larocca**	SCALE : 0 ▬ 10 km
		DATE : 1/17/02	PROJECT NO. :

PROJECT TITLE :

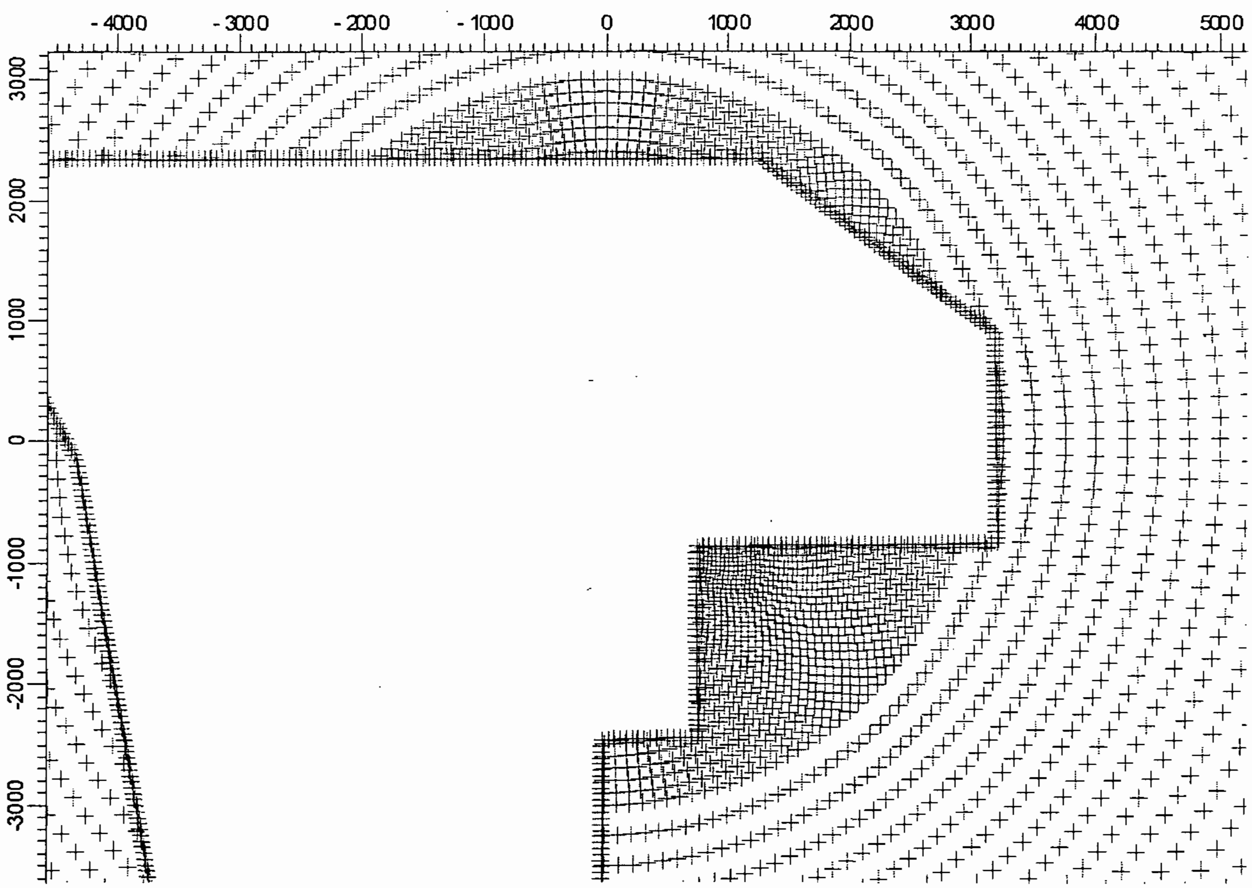
Maximum Impact Receptor Grid



COMMENTS :	SOURCES : 6	COMPANY NAME : **Golder Associates, Inc.**	
	RECEPTORS : 5526	MODELER : **Larocca**	SCALE : 0 5 km
		DATE : 1/17/02	PROJECT NO. :

PROJECT TITLE :

Maximum Impact Receptor Grid

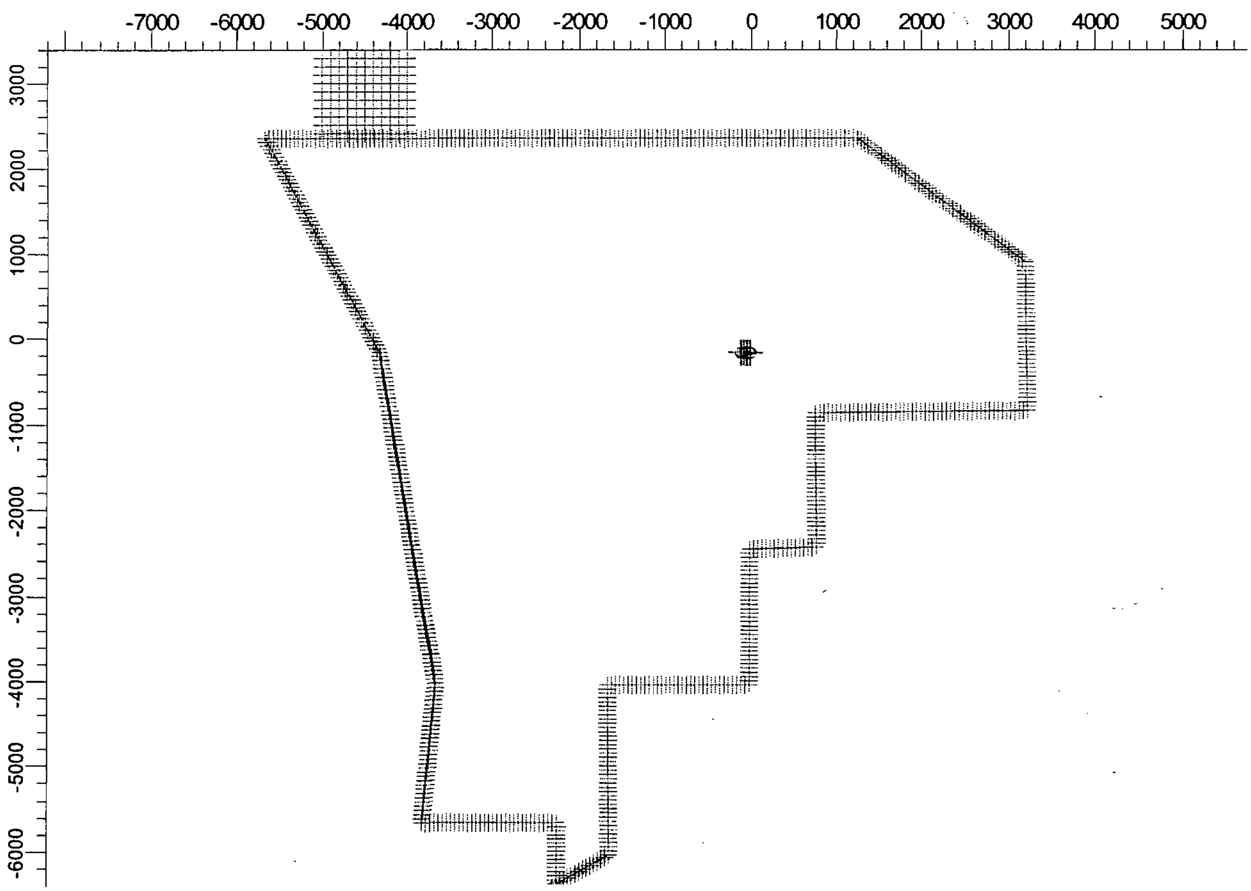


COMMENTS :	SOURCES : 6	COMPANY NAME : **Golder Associates, Inc.**	
	RECEPTORS : 5526	MODELER : **Larocca**	SCALE : 0 ▬ 1 km
		DATE : 1/17/02	PROJECT NO. :

REFINED PM_{10}
RECEPTOR GRIDS

PROJECT TITLE :

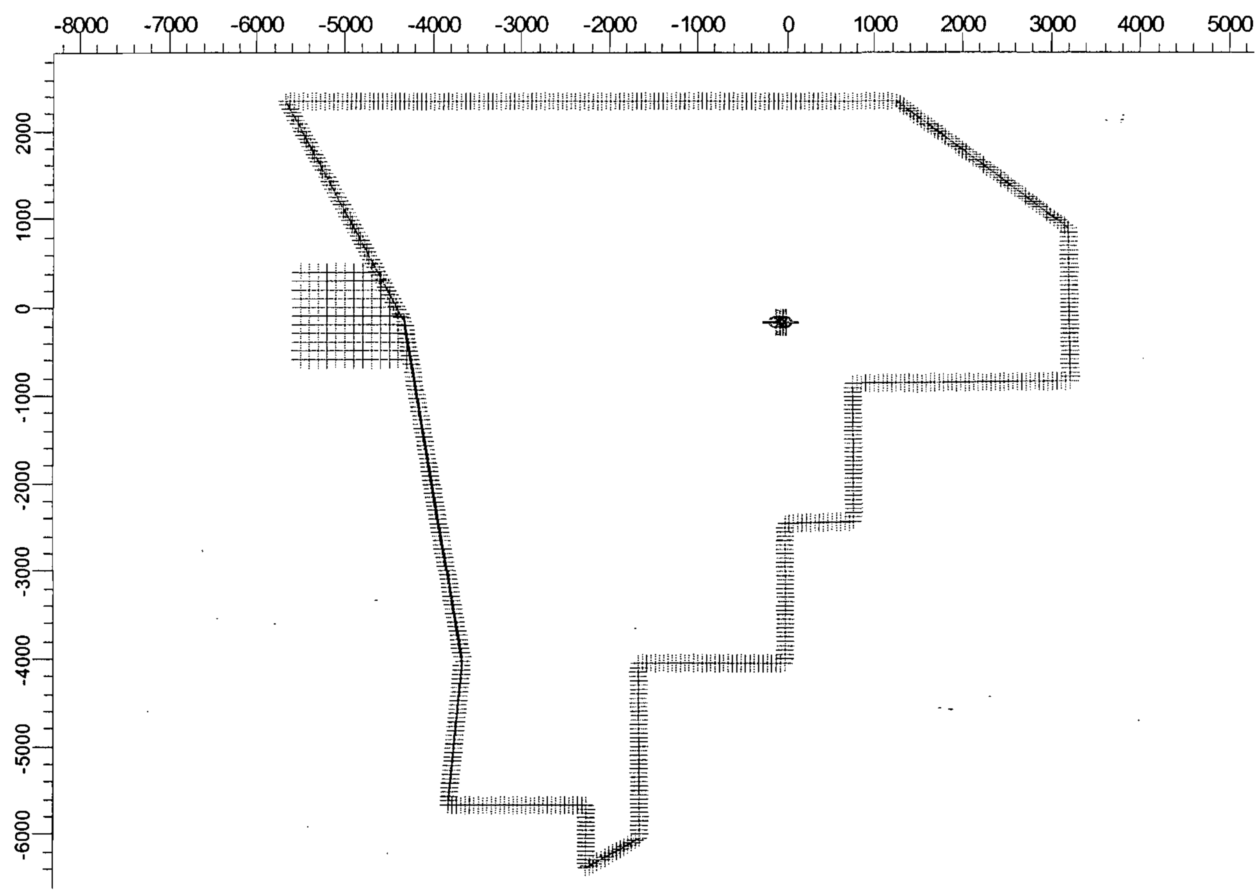
Refined PM Analysis Receptor Grid
1990 Annual Impacts



COMMENTS :	SOURCES :	COMPANY NAME :	
	18	**Golder Associates, Inc.**	
	RECEPTORS :	MODELER :	SCALE :
	778	**Larocca**	0 2 km
		DATE :	PROJECT NO. :
		1/24/02	

PROJECT TITLE :

Refined PM Analysis Receptor Grid
1987 24-hour Impacts

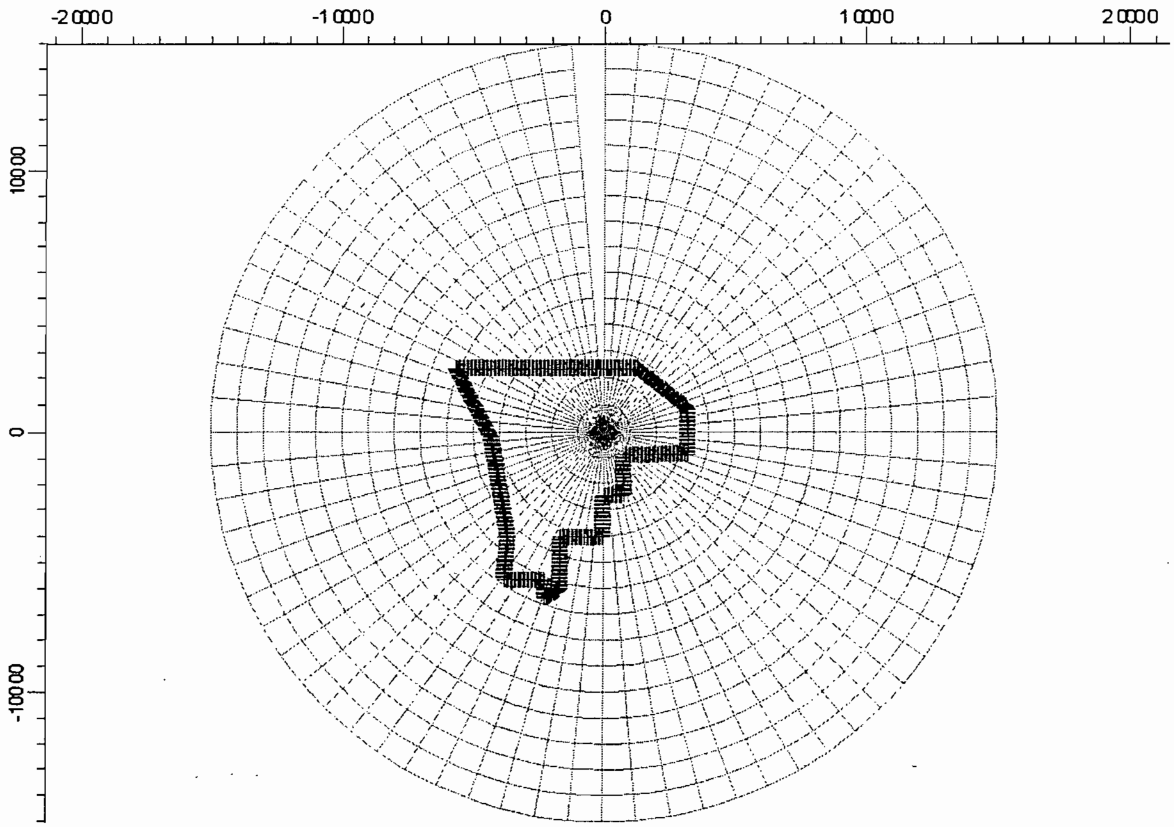


COMMENTS :	SOURCES : 18	COMPANY NAME : Golder Associates, Inc.	
	RECEPTORS : 783	MODELER : Larocca	SCALE : 0 — 2 km
		DATE : 1/24/02	PROJECT NO. :

SIGNIFICANT IMPACT AREA
POLAR RECEPTOR GRID

PROJECT TITLE :

Significant Impact Area Analysis Polar Grid



COMMENTS :	SOURCES :	COMPANY NAME :	
	36	Golder Associates, Inc.	
	RECEPTORS :	MODELER :	SCALE :
	1737	Larocca	0 — 5 km
		DATE :	PROJECT NO. :
		1/17/02	

ISCAERMODView - Lakes Environmental Software

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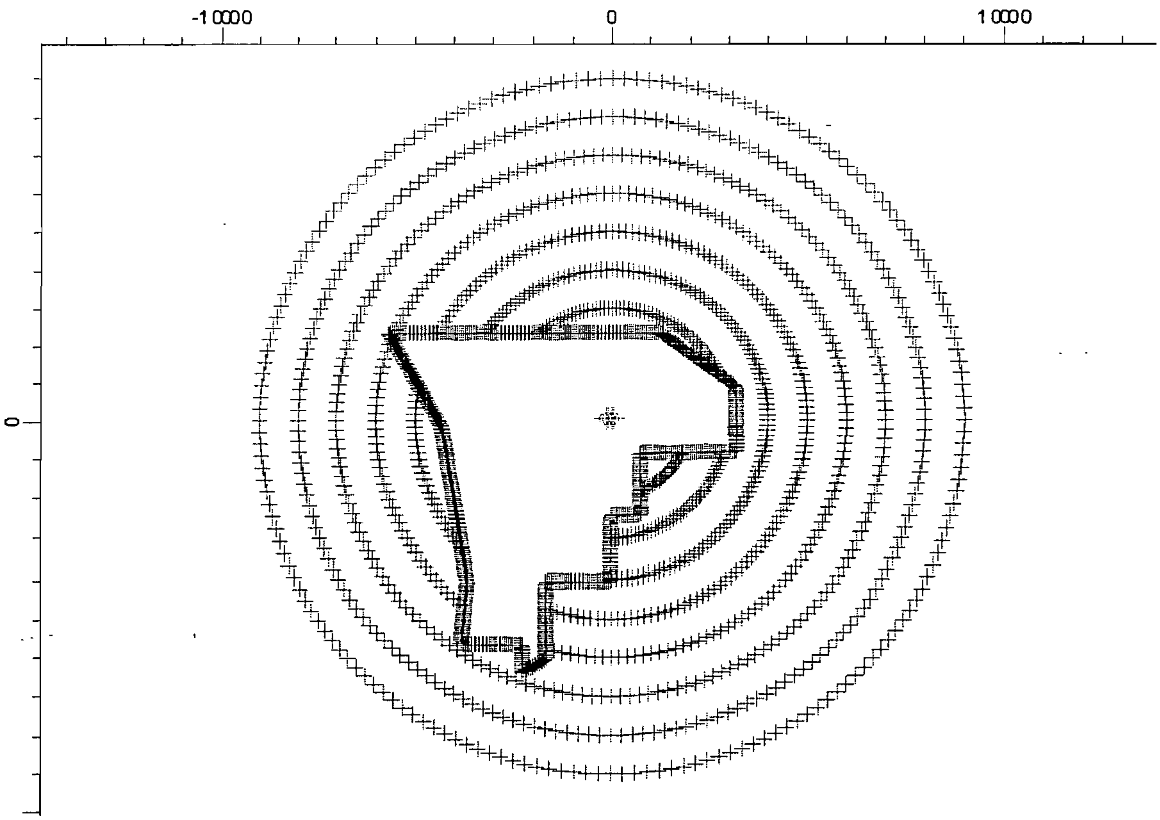
AAQS AND PSD CLASS II
INCREMENT RECEPTOR GRIDS

PROJECT TITLE :

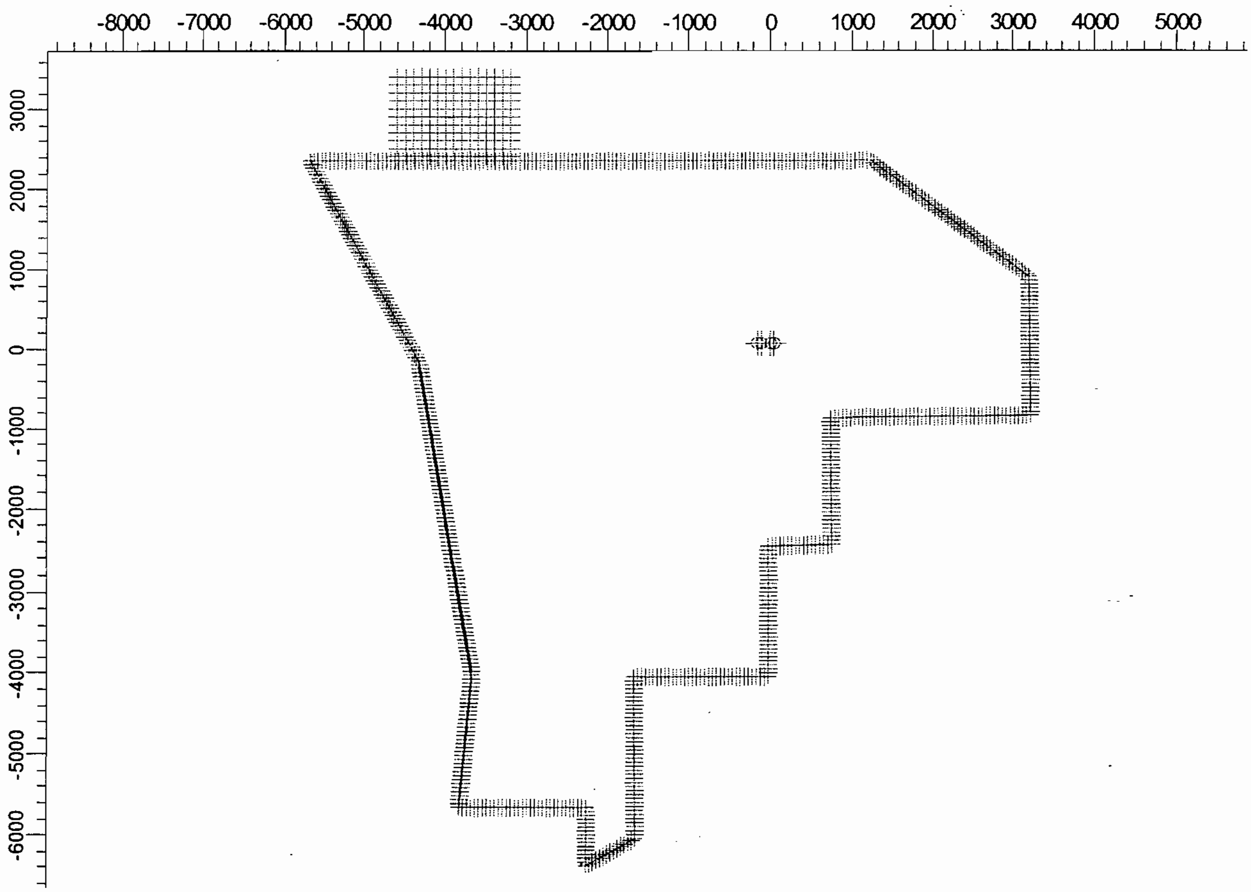
AAQS and PSD Class II Increment Analysis Grid



COMMENTS :	SOURCES :	COMPANY NAME :	
	36	Golder Associates, Inc.	
	RECEPTORS : 1750	MODELER : Larocca	SCALE : 0 5 km
		DATE : 1/17/02	PROJECT NO. :

PROJECT TITLE :

Refined AAQS Receptor Grid
1987 24-Hour SO2 Analysis



COMMENTS :	SOURCES : 36	COMPANY NAME : **Golder Associates, Inc.**	
	RECEPTORS : 822	MODELER : **Larocca**	SCALE : 0 — 2 km
		DATE : 1/24/02	PROJECT NO. :

ISC-AERMOD View - Lakes Environmental Software

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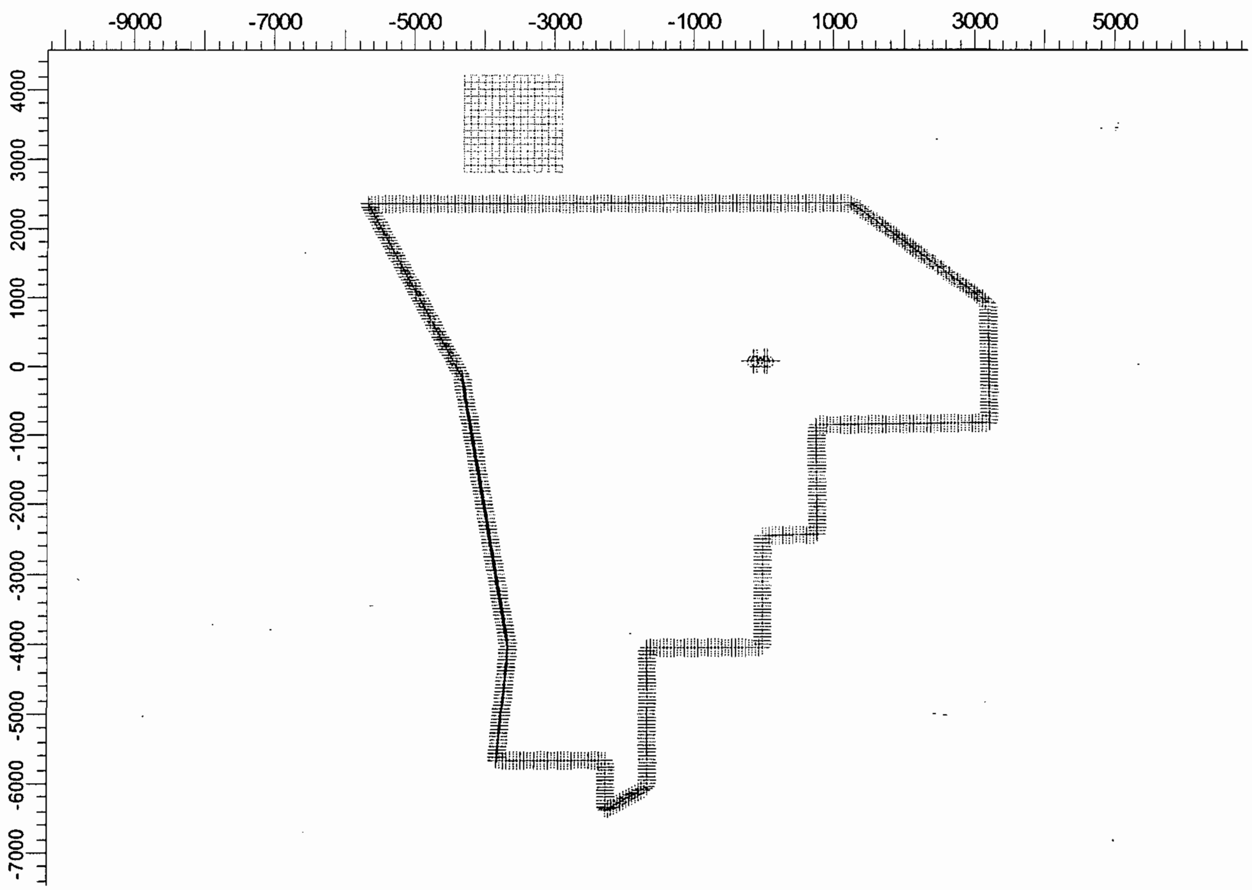
PROJECT TITLE :

Refined AAQS Receptor Grid
1991 24-Hour SO2 Analysis



COMMENTS :	SOURCES : **36**	COMPANY NAME : **Golder Associates, Inc.**	
	RECEPTORS : **882**	MODELER : **Larocca**	SCALE : 0 — 3 km
		DATE : **1/24/02**	PROJECT NO. :

ISC-AERMOD View - Lakes Environmental Software

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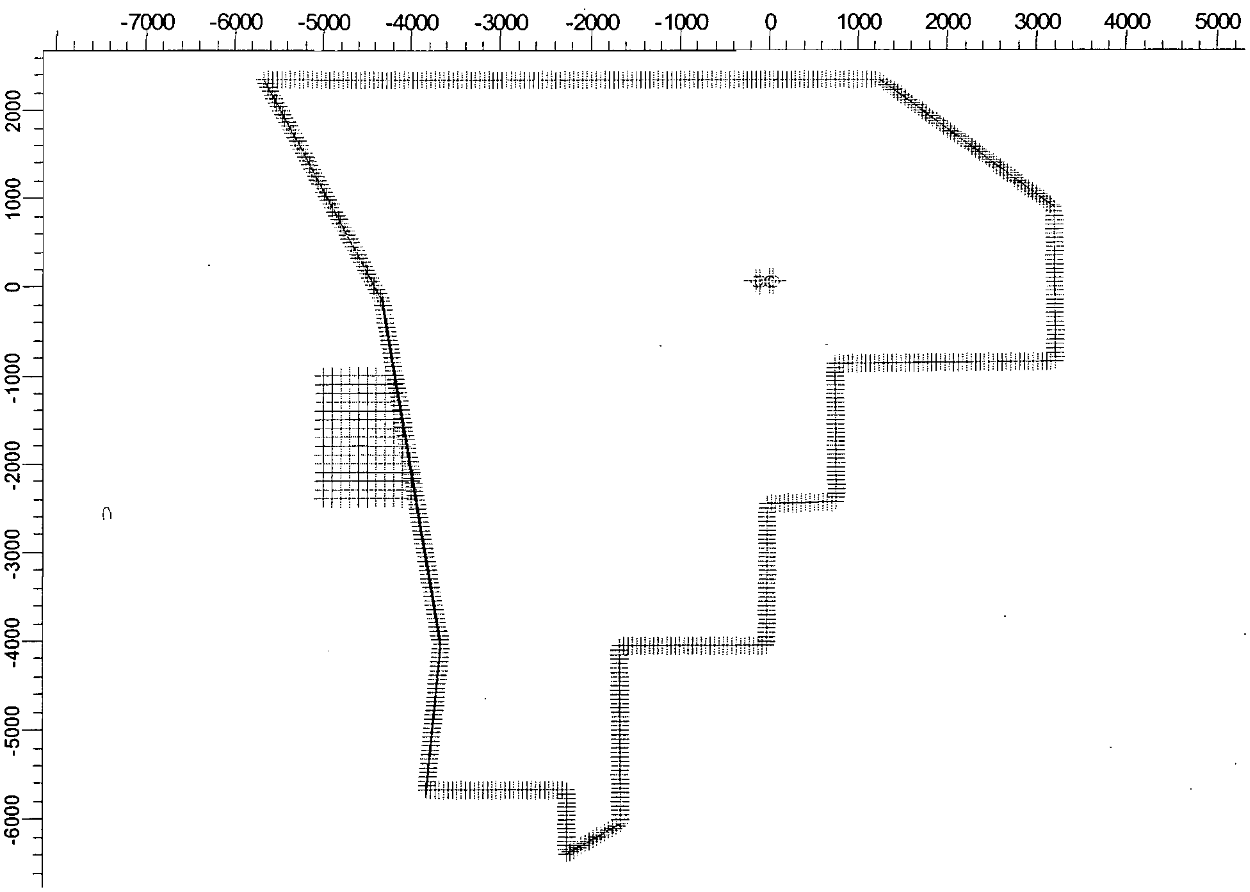
PROJECT TITLE :

Refined PSD Class II Increment Receptor Grid
1990 24-Hour SO2 Analysis



COMMENTS :	SOURCES :	COMPANY NAME :	
	36	**Golder Associates, Inc.**	
	RECEPTORS : **805**	MODELER : **Larocca**	SCALE : 0 — 2 km
		DATE : **1/24/02**	PROJECT NO. :

ISC-AERMOD View - Lakes Environmental Software

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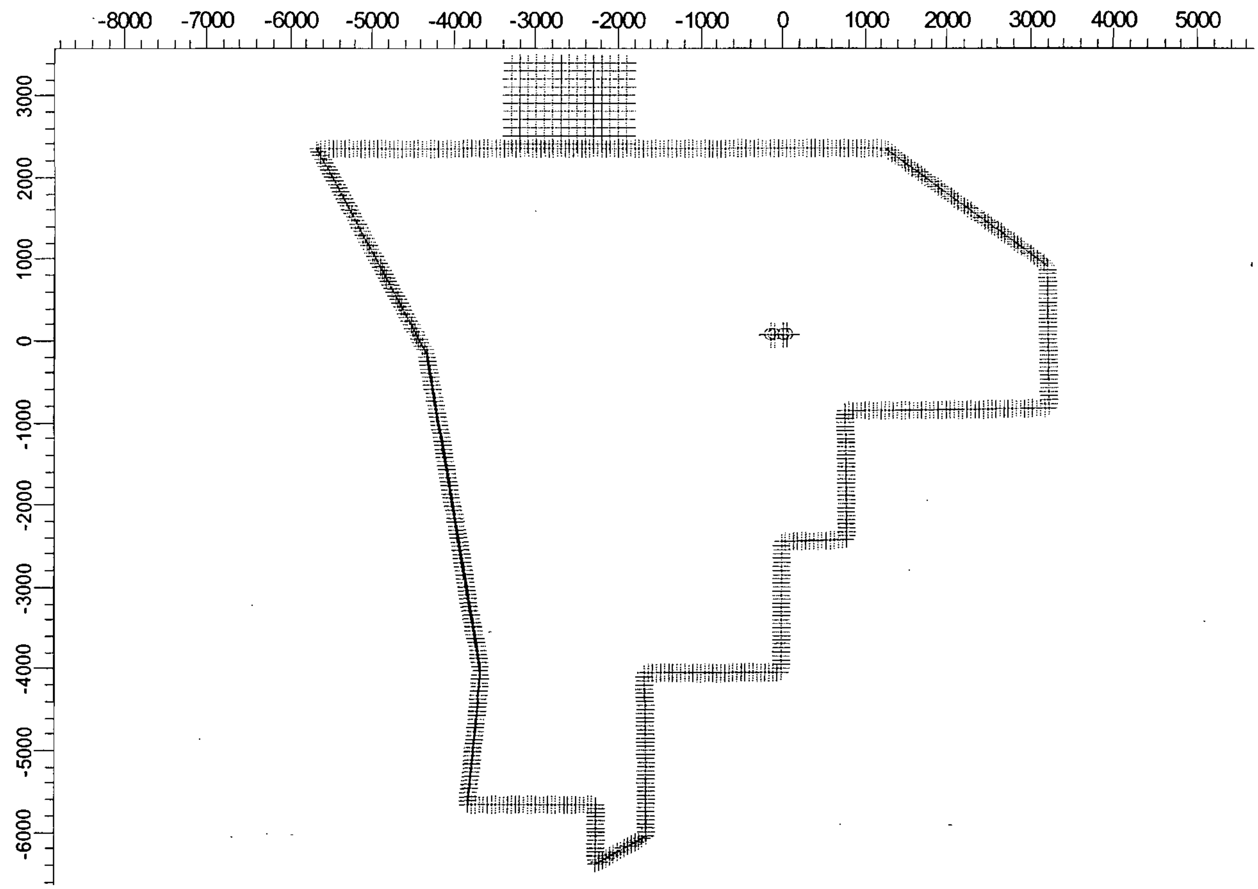
PROJECT TITLE :

Refined PSD Class II Receptor Grid
1987 24-Hour SO2 Analysis

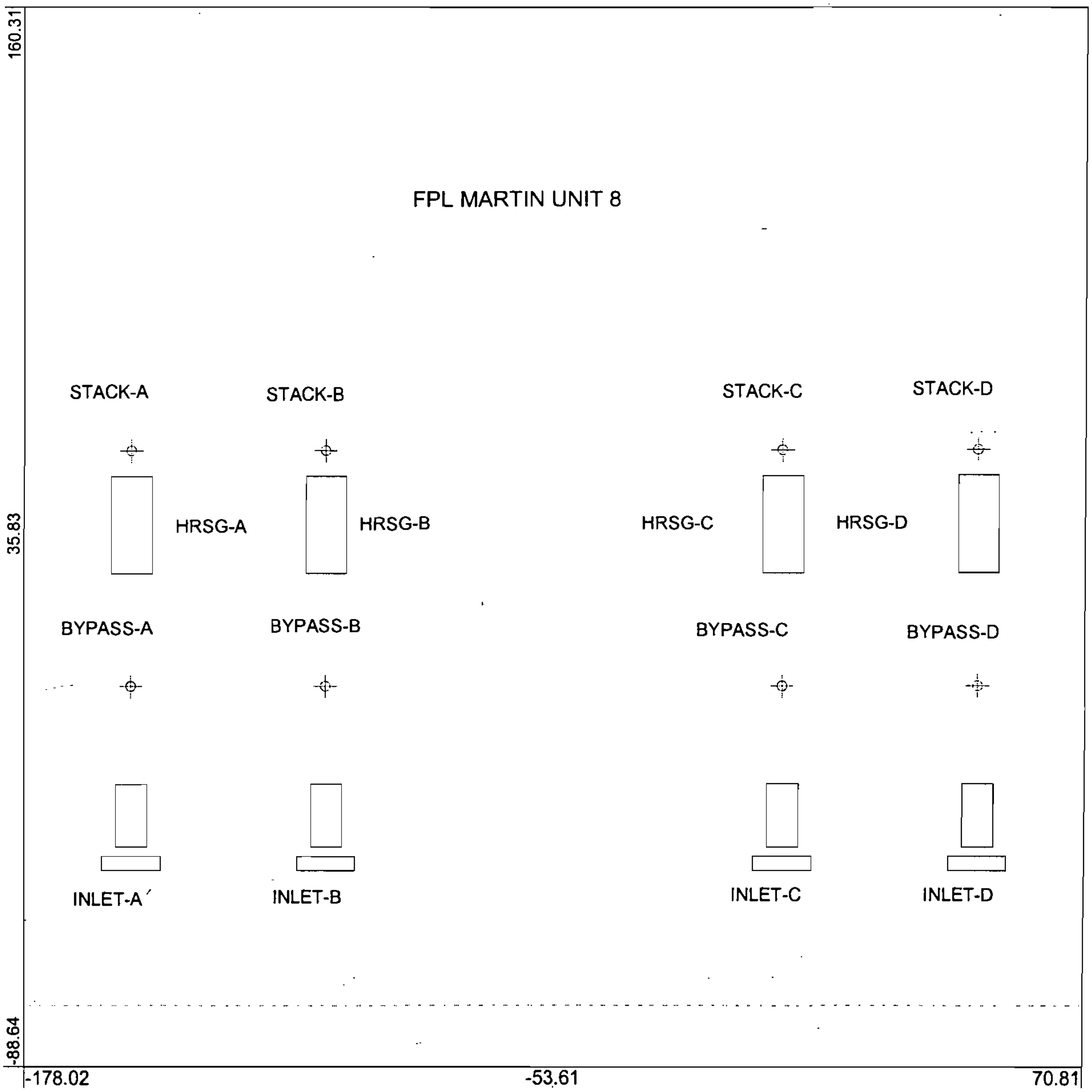


COMMENTS :	SOURCES : 36	COMPANY NAME : **Golder Associates, Inc.**	
	RECEPTORS : 822	MODELER : **Larocca**	SCALE : 0 — 2 km
		DATE : **1/24/02**	PROJECT NO. :

BUILDING PROFILE INPUT PROGRAM (BPIP) FILES

PROJECT NAME :

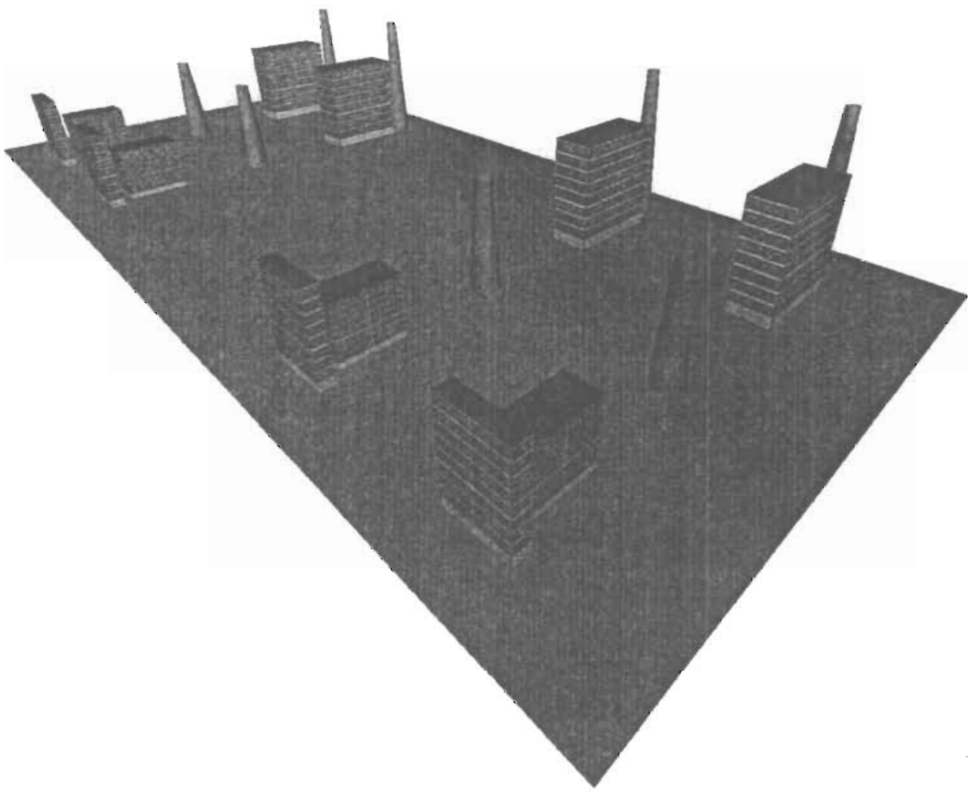
Building Structures Included in Downwash Analysis



COMMENTS :	BUILDINGS : 12	COMPANY NAME : **Golder Associates, Inc.**	
	SOURCES : 8	MODELER : **Larocca**	0 — 0.05 km
		DATE : **1/25/02**	PROJECT NO. :

TITLE:

BPIP 3D Image



COMMENTS:	STACKS: 8	COMPANY NAME: Golder Associates, Inc.	
	BUILDINGS: 12	MODELER: Larocca	PROJECT NO.: 0
		DATE: 1/17/02	

```
'D:\martin\bpip\martin3.bpv'
'ST'
'Meters'  1.00000000
'UTMN'  270.0000
12
'HRSG4'  1           0.000
   4          25.300
              49.210          157.430
              49.210          147.980
              26.510          147.980
              26.510          157.430
'HRSG2'  1           0.000
   4          25.300
              49.213          111.710
              49.213          102.260
              26.513          102.260
              26.510          111.710
'HRSG3'  1           0.000
   4          25.300
              49.213            4.572
              49.213           -4.880
              26.513           -4.880
              26.513            4.570
'HRSG4'  1           0.000
   4          25.300
              49.213          -41.148
              49.213          -50.598
              26.513          -50.600
              26.513          -41.148
'INLET3'  1          0.000
   4          20.270
             -40.044            6.851
             -40.044           -6.749
             -43.244           -6.749
             -43.240            6.851
'INLET4'  1          0.000
   4          20.270
             -40.044          -38.869
             -40.044          -52.469
             -43.244          -52.469
             -43.244          -38.869
'DUCT3'  1           0.000
   4          13.720
             -22.922            3.642
             -22.922           -3.658
             -37.642           -3.658
             -37.642            3.642
'DUCT4'  1           0.000
   4          13.720
             -22.922          -42.078
             -22.922          -49.378
             -37.642          -49.378
             -37.642          -42.078
'DUCT1'  1           0.000
   4          13.720
             -23.000          156.400
             -23.000          149.100
             -37.720          149.100
             -37.720          156.400
'DUCT2'  1           0.000
   4          13.720
             -23.000          110.690
             -23.000          103.390
             -37.720          103.390
             -37.720          110.690
'INLET1'  1          0.000
   4          20.270
             -40.140          159.500
             -40.140          145.900
             -43.340          145.900
             -43.340          159.500
'INLET2'  1          0.000
   4          20.270
             -40.140          113.780
```

	-40.140	100.180		
	-43.340	100.180		
	-43.340	113.780		
8				
'SC3'	0.000	24.384	0.000	0.000
'SC4'	0.000	24.384	0.000	-45.720
'CC1'	0.000	36.576	55.009	152.858
'CC2'	0.000	36.576	55.009	107.138
'CC3'	0.000	36.576	55.009	0.000
'CC4'	0.000	36.576	55.009	-45.720
'OLDSC1'	0.000	24.384	0.000	152.858
'OLDSC2'	0.000	24.384	0.000	107.138

BPIP (Dated: 95086)

DATE : 1/ 3/ 2
TIME : 13:10:12
D:\martin\bpip\martin3.bpv

============================
BPIP PROCESSING INFORMATION:
============================

The ST flag has been set for processing for an ISCST2 run.

Inputs entered in Meters will be converted to meters using a conversion factor of 1.0000. Output will be in meters.

UTMP is set to UTMN. The input is assumed to be in a local X-Y coordinate system as opposed to a UTM coordinate system. True North is in the positive Y direction.

Plant north is set to 270.00 degrees with respect to True North.

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PRELIMINARY* GEP STACK HEIGHT RESULTS TABLE
(Output Units: meters)

Stack Name	Stack Height	Stack-Building Base Elevation Differences	GEP** EQN1	Preliminary* GEP Stack Height Value
SC3	24.38	0.00	62.19	65.00
SC4	24.38	0.00	62.02	65.00
CC1	36.58	0.00	62.19	65.00
CC2	36.58	0.00	62.18	65.00
CC3	36.58	0.00	62.18	65.00
CC4	36.58	0.00	62.18	65.00
OLDSC1	24.38	0.00	62.03	65.00
OLDSC2	24.38	0.00	62.18	65.00

* Results are based on Determinants 1 & 2 on pages 1 & 2 of the GEP Technical Support Document. Determinant 3 may be investigated for additional stack height credit. Final values result after Determinant 3 has been taken into consideration.

** Results were derived from Equation 1 on page 6 of GEP Technical Support Document. Values have been adjusted for any stack-building base elevation differences.

Note: Criteria for determining stack heights for modeling emission limitations for a source can be found in Table 3.1 of the GEP Technical Support Document.

BPIP (Dated: 95086)

DATE : 1/ 3/ 2
TIME : 13:10:12

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BPIP output is in meters

SO BUILDHGT SC3	25.30	25.30	25.30	0.00	0.00	0.00
SO BUILDHGT SC3	25.30	0.00	0.00	25.30	25.30	25.30
SO BUILDHGT SC3	0.00	0.00	25.30	25.30	25.30	25.30
SO BUILDHGT SC3	25.30	25.30	25.30	25.30	25.30	25.30

SO BUILDHGT SC3	25.30	0.00	0.00	0.00	13.72	13.72
SO BUILDHGT SC3	20.27	20.27	25.30	25.30	25.30	20.27
SO BUILDWID SC3	13.25	16.65	19.54	0.00	0.00	0.00
SO BUILDWID SC3	24.56	0.00	0.00	24.00	24.57	24.39
SO BUILDWID SC3	0.00	0.00	19.53	16.64	13.25	9.45
SO BUILDWID SC3	13.25	16.65	19.54	21.83	23.46	24.38
SO BUILDWID SC3	24.56	0.00	0.00	0.00	16.33	16.40
SO BUILDWID SC3	11.19	12.48	19.53	16.64	13.25	13.60
SO BUILDHGT SC4	25.30	25.30	25.30	20.27	20.27	13.72
SO BUILDHGT SC4	13.72	0.00	0.00	0.00	25.30	25.30
SO BUILDHGT SC4	25.30	25.30	25.30	25.30	25.30	25.30
SO BUILDHGT SC4	25.30	25.30	25.30	0.00	0.00	0.00
SO BUILDHGT SC4	0.00	0.00	0.00	0.00	25.30	25.30
SO BUILDHGT SC4	0.00	0.00	25.30	25.30	25.30	20.27
SO BUILDWID SC4	13.25	16.65	19.54	12.48	11.19	16.40
SO BUILDWID SC4	16.33	0.00	0.00	0.00	24.48	24.38
SO BUILDWID SC4	23.46	21.83	19.53	16.64	13.25	9.45
SO BUILDWID SC4	13.25	16.65	19.54	0.00	0.00	0.00
SO BUILDWID SC4	0.00	0.00	0.00	0.00	24.48	24.38
SO BUILDWID SC4	0.00	0.00	19.53	16.64	13.25	13.60
SO BUILDHGT CC1	25.30	25.30	25.30	25.30	25.30	25.30
SO BUILDHGT CC1	25.30	25.30	25.30	25.30	25.30	25.30
SO BUILDHGT CC1	25.30	25.30	25.30	25.30	25.30	25.30
SO BUILDHGT CC1	25.30	25.30	25.30	25.30	25.30	25.30
SO BUILDHGT CC1	25.30	25.30	25.30	25.30	25.30	25.30
SO BUILDHGT CC1	25.30	25.30	25.30	25.30	25.30	25.30
SO BUILDWID CC1	13.25	16.64	19.53	21.83	23.46	24.38
SO BUILDWID CC1	24.56	24.00	22.70	24.00	24.57	24.39
SO BUILDWID CC1	23.47	21.83	19.53	16.64	13.25	9.45
SO BUILDWID CC1	13.25	16.64	19.53	21.83	23.46	24.38
SO BUILDWID CC1	24.56	24.00	22.70	24.00	24.57	24.39
SO BUILDWID CC1	23.47	21.83	19.53	16.64	13.25	9.45
SO BUILDHGT CC2	25.30	25.30	25.30	25.30	25.30	25.30
SO BUILDHGT CC2	25.30	25.30	25.30	25.30	25.30	25.30
SO BUILDHGT CC2	25.30	25.30	25.30	25.30	25.30	25.30
SO BUILDHGT CC2	25.30	25.30	25.30	25.30	25.30	25.30
SO BUILDHGT CC2	25.30	25.30	25.30	25.30	25.30	25.30
SO BUILDHGT CC2	25.30	25.30	25.30	25.30	25.30	25.30
SO BUILDWID CC2	13.25	16.64	19.53	21.83	23.46	24.38
SO BUILDWID CC2	24.56	24.00	22.70	24.00	24.57	24.39
SO BUILDWID CC2	23.47	21.83	19.54	16.64	13.25	9.45
SO BUILDWID CC2	13.25	16.64	19.53	21.83	23.46	24.38
SO BUILDWID CC2	24.56	24.00	22.70	24.00	24.57	24.39
SO BUILDWID CC2	23.47	21.83	19.54	16.64	13.25	9.45
SO BUILDHGT CC3	25.30	25.30	25.30	25.30	25.30	25.30
SO BUILDHGT CC3	25.30	25.30	25.30	25.30	25.30	25.30
SO BUILDHGT CC3	25.30	25.30	25.30	25.30	25.30	25.30
SO BUILDHGT CC3	25.30	25.30	25.30	25.30	25.30	25.30
SO BUILDHGT CC3	25.30	25.30	25.30	25.30	25.30	25.30
SO BUILDHGT CC3	25.30	25.30	25.30	25.30	25.30	25.30
SO BUILDWID CC3	13.25	16.65	19.54	21.83	23.46	24.38
SO BUILDWID CC3	24.56	24.00	22.70	24.00	24.56	24.38
SO BUILDWID CC3	23.46	21.83	19.53	16.64	13.25	9.45
SO BUILDWID CC3	13.25	16.65	19.54	21.83	23.46	24.38
SO BUILDWID CC3	24.56	24.00	22.70	24.00	24.56	24.38
SO BUILDWID CC3	23.46	21.83	19.53	16.64	13.25	9.45
SO BUILDHGT CC4	25.30	25.30	25.30	25.30	25.30	25.30
SO BUILDHGT CC4	25.30	25.30	25.30	25.30	25.30	25.30
SO BUILDHGT CC4	25.30	25.30	25.30	25.30	25.30	25.30
SO BUILDHGT CC4	25.30	25.30	25.30	25.30	25.30	25.30
SO BUILDHGT CC4	25.30	25.30	25.30	25.30	25.30	25.30
SO BUILDHGT CC4	25.30	25.30	25.30	25.30	25.30	25.30
SO BUILDWID CC4	13.25	16.65	19.54	21.83	23.46	24.38
SO BUILDWID CC4	24.56	24.00	22.70	24.00	24.56	24.38

```
SO BUILDWID CC4          23.46   21.83   19.53   16.64   13.25    9.45
SO BUILDWID CC4          13.25   16.65   19.54   21.83   23.46   24.38
SO BUILDWID CC4          24.56   24.00   22.70   24.00   24.56   24.38
SO BUILDWID CC4          23.46   21.83   19.53   16.64   13.25    9.45

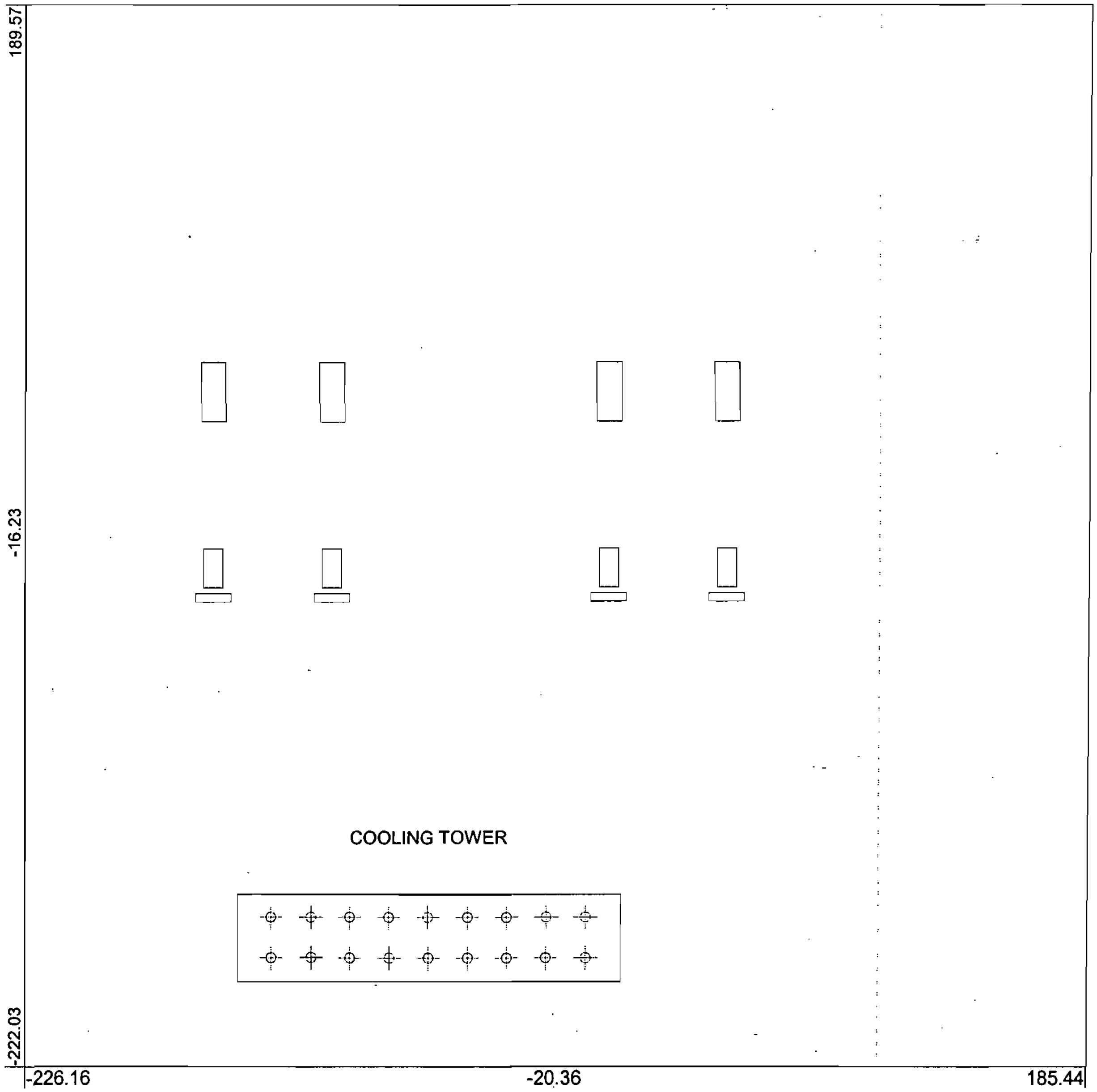
SO BUILDHGT OLDSC1       25.30   25.30   25.30    0.00    0.00    0.00
SO BUILDHGT OLDSC1       25.30    0.00    0.00    0.00    0.00    0.00
SO BUILDHGT OLDSC1        0.00    0.00   25.30   25.30   25.30   25.30
SO BUILDHGT OLDSC1       25.30   25.30   25.30   25.30   25.30   25.30
SO BUILDHGT OLDSC1       25.30    0.00    0.00    0.00   13.72   13.72
SO BUILDHGT OLDSC1       20.27   20.27   25.30   25.30   25.30   20.27
SO BUILDWID OLDSC1       13.25   16.64   19.53    0.00    0.00    0.00
SO BUILDWID OLDSC1       24.49    0.00    0.00    0.00    0.00    0.00
SO BUILDWID OLDSC1        0.00    0.00   19.53   16.64   13.25    9.45
SO BUILDWID OLDSC1       13.25   16.64   19.53   21.83   23.46   24.38
SO BUILDWID OLDSC1       24.49    0.00    0.00    0.00   16.33   16.40
SO BUILDWID OLDSC1       11.19   12.48   19.53   16.64   13.25   13.60

SO BUILDHGT OLDSC2       25.30   25.30   25.30   20.27   20.27   13.72
SO BUILDHGT OLDSC2       13.72    0.00    0.00    0.00   25.30   25.30
SO BUILDHGT OLDSC2       25.30   25.30   25.30   25.30   25.30   25.30
SO BUILDHGT OLDSC2       25.30   25.30   25.30    0.00    0.00   25.30
SO BUILDHGT OLDSC2       25.30   25.30    0.00    0.00   25.30   25.30
SO BUILDHGT OLDSC2        0.00    0.00   25.30   25.30   25.30   20.27
SO BUILDWID OLDSC2       13.25   16.64   19.53   12.48   11.19   16.40
SO BUILDWID OLDSC2       16.33    0.00    0.00    0.00   24.56   24.38
SO BUILDWID OLDSC2       23.46   21.83   19.54   16.64   13.25    9.45
SO BUILDWID OLDSC2       13.25   16.64   19.53    0.00    0.00   24.38
SO BUILDWID OLDSC2       24.56   24.00    0.00    0.00   24.56   24.38
SO BUILDWID OLDSC2        0.00    0.00   19.54   16.64   13.25   13.60
```

COOLING TOWER

PROJECT NAME :

Building Structures Included in Cooling Tower Downwash Analysis

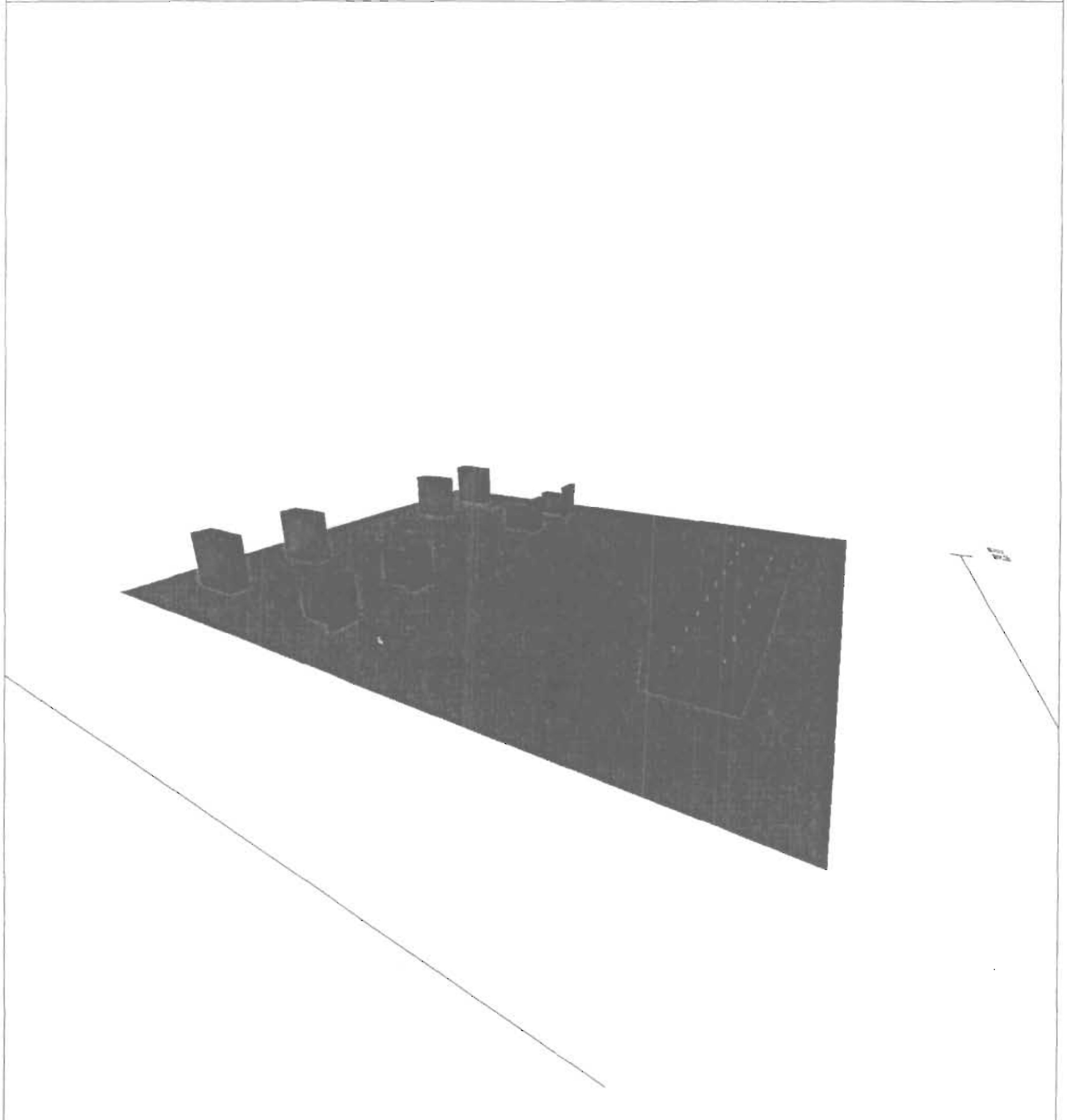


COMMENTS :	BUILDINGS : 13	COMPANY NAME : Golder Associates, Inc.	
	SOURCES : 18	MODELER : Larocca	0 0.05 km
		DATE : 1/25/02	PROJECT NO. :

BPIP View by Lakes Environmental Software D:\martin\bpip\cool.bpv

TITLE:

BPIP 3D Image



COMMENTS:	STACKS:	COMPANY NAME:	
	18	Golder Associates, Inc.	
	BUILDINGS: 13	MODELER: Larocca	PROJECT NO.: 0
		DATE: 1/22/02	

```
'D:\manatee\bpip\cool.bpv'
'ST'
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'UTMN'  0.0000
13
'BLDG1'  1            0.000
    4          12.190
             -143.060          -156.690
                5.000          -156.690
                5.000          -189.570
             -143.060          -189.570
'HRSGA'  1            0.000
    4          25.300
             -157.440            49.170
             -147.840            49.170
             -147.840            26.420
             -157.440            26.420
'HRSGB'  1            0.000
    4          25.300
             -111.750            49.170
             -102.150            49.170
             -102.150            26.420
             -111.750            26.420
'HRSGC'  1            0.000
    4          25.300
               -4.600            49.170
                5.000            49.170
                5.000            26.420
               -4.600            26.420
'HRSGD'  1            0.000
    4          25.300
               41.190            49.170
               50.680            49.170
               50.680            26.420
               41.190            26.420
'INLETA'  1            0.000
    4          20.270
             -159.640           -40.150
             -145.890           -40.150
             -145.890           -43.450
             -159.640           -43.450
'INLETB'  1            0.000
    4          20.270
             -113.920           -40.150
             -100.170           -40.150
             -100.170           -43.450
             -113.920           -43.450
'INLETC'  1            0.000
    4          20.270
               -6.860           -40.060
                6.800           -40.060
                6.800           -43.360
               -6.860           -43.360
'INLETD'  1            0.000
    4          20.270
               38.900           -40.060
               52.550           -40.060
               52.550           -43.360
               38.900           -43.360
'DUCTA'  1            0.000
    4          13.720
             -156.370           -23.050
             -149.030           -23.050
             -149.030           -37.820
             -156.370           -37.820
'DUCTB'  1            0.000
    4          13.720
             -110.650           -23.050
             -103.310           -23.050
             -103.310           -37.820
             -110.650           -37.820
'DUCTC'  1            0.000
    4          13.720
               -3.650           -22.950
```

```
              3.780        -22.950
              3.780        -37.820
             -3.650        -37.820
'DUCTD'  1          0.000
    4        13.720
             42.100        -22.950
             49.440        -22.950
             49.440        -37.820
             42.100        -37.820
18
```

'CELL01'	0.000	13.716	-130.330	-165.320
'CELL02'	0.000	13.716	-114.950	-165.320
'CELL03'	0.000	13.716	-99.940	-165.320
'CELL04'	0.000	13.716	-84.770	-165.320
'CELL05'	0.000	13.716	-69.600	-165.320
'CELL06'	0.000	13.716	-54.210	-165.320
'CELL07'	0.000	13.716	-39.040	-165.320
'CELL08'	0.000	13.716	-23.600	-165.320
'CELL09'	0.000	13.716	-8.430	-165.320
'CELL10'	0.000	13.716	-130.330	-180.550
'CELL11'	0.000	13.716	-114.950	-180.330
'CELL12'	0.000	13.716	-99.940	-180.550
'CELL13'	0.000	13.716	-84.550	-180.550
'CELL14'	0.000	13.716	-69.380	-180.550
'CELL15'	0.000	13.716	-54.210	-180.550
'CELL16'	0.000	13.716	-39.040	-180.550
'CELL17'	0.000	13.716	-23.820	-180.550
'CELL18'	0.000	13.716	-8.430	-180.550

BPIP (Dated: 95086)

DATE : 1/23/ 2
TIME : 9:35:33
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BPIP PROCESSING INFORMATION:
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The ST flag has been set for processing for an ISCST2 run.

Inputs entered in Meters will be converted to meters using a conversion factor of 1.0000. Output will be in meters.

UTMP is set to UTMN. The input is assumed to be in a local X-Y coordinate system as opposed to a UTM coordinate system. True North is in the positive Y direction.

Plant north is set to 0.00 degrees with respect to True North.

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PRELIMINARY* GEP STACK HEIGHT RESULTS TABLE
(Output Units: meters)

Stack Name	Stack Height	Stack-Building Base Elevation Differences	GEP** EQN1	Preliminary* GEP Stack Height Value
CELL01	13.72	0.00	30.47	65.00
CELL02	13.72	0.00	30.47	65.00
CELL03	13.72	0.00	30.47	65.00
CELL04	13.72	0.00	30.47	65.00
CELL05	13.72	0.00	30.47	65.00
CELL06	13.72	0.00	30.47	65.00
CELL07	13.72	0.00	30.47	65.00
CELL08	13.72	0.00	30.47	65.00
CELL09	13.72	0.00	30.47	65.00
CELL10	13.72	0.00	30.47	65.00
CELL11	13.72	0.00	30.47	65.00
CELL12	13.72	0.00	30.47	65.00
CELL13	13.72	0.00	30.47	65.00
CELL14	13.72	0.00	30.47	65.00
CELL15	13.72	0.00	30.47	65.00
CELL16	13.72	0.00	30.47	65.00
CELL17	13.72	0.00	30.47	65.00
CELL18	13.72	0.00	30.47	65.00

* Results are based on Determinants 1 & 2 on pages 1 & 2 of the GEP Technical Support Document. Determinant 3 may be investigated for additional stack height credit. Final values result after Determinant 3 has been taken into consideration.

** Results were derived from Equation 1 on page 6 of GEP Technical Support Document. Values have been adjusted for any stack-building base elevation differences.

Note: Criteria for determining stack heights for modeling emission limitations for a source can be found in Table 3.1 of the GEP Technical Support Document.

BPIP (Dated: 95086)

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BPIP output is in meters

SO	BUILDHGT	CELL01	12.19	12.19	12.19	12.19	12.19	12.19
SO	BUILDHGT	CELL01	12.19	12.19	12.19	12.19	12.19	12.19
SO	BUILDHGT	CELL01	12.19	12.19	12.19	12.19	12.19	12.19
SO	BUILDHGT	CELL01	12.19	12.19	12.19	12.19	12.19	12.19
SO	BUILDHGT	CELL01	12.19	12.19	12.19	12.19	12.19	12.19
SO	BUILDHGT	CELL01	12.19	12.19	12.19	12.19	12.19	12.19
SO	BUILDWID	CELL01	151.52	150.38	144.66	134.56	120.36	102.50
SO	BUILDWID	CELL01	81.54	58.09	32.88	58.09	81.54	102.50
SO	BUILDWID	CELL01	120.36	134.56	144.66	150.38	151.52	148.06
SO	BUILDWID	CELL01	151.52	150.38	144.66	134.56	120.36	102.50
SO	BUILDWID	CELL01	81.54	58.09	32.88	58.09	81.54	102.50
SO	BUILDWID	CELL01	120.36	134.56	144.66	150.38	151.52	148.06

SO	BUILDHGT	CELL02	12.19	12.19	12.19	12.19	12.19	12.19
SO	BUILDHGT	CELL02	12.19	12.19	12.19	12.19	12.19	12.19
SO	BUILDHGT	CELL02	12.19	12.19	12.19	12.19	12.19	12.19
SO	BUILDHGT	CELL02	12.19	12.19	12.19	12.19	12.19	12.19
SO	BUILDHGT	CELL02	12.19	12.19	12.19	12.19	12.19	12.19
SO	BUILDHGT	CELL02	12.19	12.19	12.19	12.19	12.19	12.19
SO	BUILDWID	CELL02	151.52	150.38	144.66	134.56	120.36	102.50
SO	BUILDWID	CELL02	81.54	58.09	32.88	58.09	81.54	102.50
SO	BUILDWID	CELL02	120.36	134.56	144.66	150.38	151.52	148.06
SO	BUILDWID	CELL02	151.52	150.38	144.66	134.56	120.36	102.50
SO	BUILDWID	CELL02	81.54	58.09	32.88	58.09	81.54	102.50
SO	BUILDWID	CELL02	120.36	134.56	144.66	150.38	151.52	148.06

SO	BUILDHGT	CELL03	12.19	12.19	12.19	12.19	12.19	12.19
SO	BUILDHGT	CELL03	12.19	12.19	12.19	12.19	12.19	12.19
SO	BUILDHGT	CELL03	12.19	12.19	12.19	12.19	12.19	12.19
SO	BUILDHGT	CELL03	12.19	12.19	12.19	12.19	12.19	12.19
SO	BUILDHGT	CELL03	12.19	12.19	12.19	12.19	12.19	12.19
SO	BUILDHGT	CELL03	12.19	12.19	12.19	12.19	12.19	12.19
SO	BUILDWID	CELL03	151.52	150.38	144.66	134.56	120.36	102.50
SO	BUILDWID	CELL03	81.54	58.09	32.88	58.09	81.54	102.50
SO	BUILDWID	CELL03	120.36	134.56	144.66	150.38	151.52	148.06
SO	BUILDWID	CELL03	151.52	150.38	144.66	134.56	120.36	102.50
SO	BUILDWID	CELL03	81.54	58.09	32.88	58.09	81.54	102.50
SO	BUILDWID	CELL03	120.36	134.56	144.66	150.38	151.52	148.06

SO	BUILDHGT	CELL04	12.19	12.19	12.19	12.19	12.19	12.19
SO	BUILDHGT	CELL04	12.19	12.19	12.19	12.19	12.19	12.19
SO	BUILDHGT	CELL04	12.19	12.19	12.19	12.19	12.19	12.19
SO	BUILDHGT	CELL04	12.19	12.19	12.19	12.19	12.19	12.19
SO	BUILDHGT	CELL04	12.19	12.19	12.19	12.19	12.19	12.19
SO	BUILDHGT	CELL04	12.19	12.19	12.19	12.19	12.19	12.19
SO	BUILDWID	CELL04	151.52	150.38	144.66	134.56	120.36	102.50
SO	BUILDWID	CELL04	81.54	58.09	32.88	58.09	81.54	102.50
SO	BUILDWID	CELL04	120.36	134.56	144.66	150.38	151.52	148.06
SO	BUILDWID	CELL04	151.52	150.38	144.66	134.56	120.36	102.50
SO	BUILDWID	CELL04	81.54	58.09	32.88	58.09	81.54	102.50
SO	BUILDWID	CELL04	120.36	134.56	144.66	150.38	151.52	148.06

SO	BUILDHGT	CELL05	12.19	12.19	12.19	12.19	12.19	12.19
SO	BUILDHGT	CELL05	12.19	12.19	12.19	12.19	12.19	12.19
SO	BUILDHGT	CELL05	12.19	12.19	12.19	12.19	12.19	12.19
SO	BUILDHGT	CELL05	12.19	12.19	12.19	12.19	12.19	12.19
SO	BUILDHGT	CELL05	12.19	12.19	12.19	12.19	12.19	12.19
SO	BUILDHGT	CELL05	12.19	12.19	12.19	12.19	12.19	12.19
SO	BUILDWID	CELL05	151.52	150.38	144.66	134.56	120.36	102.50
SO	BUILDWID	CELL05	81.54	58.09	32.88	58.09	81.54	102.50
SO	BUILDWID	CELL05	120.36	134.56	144.66	150.38	151.52	148.06
SO	BUILDWID	CELL05	151.52	150.38	144.66	134.56	120.36	102.50
SO	BUILDWID	CELL05	81.54	58.09	32.88	58.09	81.54	102.50
SO	BUILDWID	CELL05	120.36	134.56	144.66	150.38	151.52	148.06

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SO BUILDHGT CELL06     12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDHGT CELL06     12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDHGT CELL06     12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDHGT CELL06     12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDHGT CELL06     12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDHGT CELL06     12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDWID CELL06    151.52  150.38  144.66  134.56  120.36  102.50
SO BUILDWID CELL06     81.54   58.09   32.88   58.09   81.54  102.50
SO BUILDWID CELL06    120.36  134.56  144.66  150.38  151.52  148.06
SO BUILDWID CELL06    151.52  150.38  144.66  134.56  120.36  102.50
SO BUILDWID CELL06     81.54   58.09   32.88   58.09   81.54  102.50
SO BUILDWID CELL06    120.36  134.56  144.66  150.38  151.52  148.06

SO BUILDHGT CELL07     12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDHGT CELL07     12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDHGT CELL07     12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDHGT CELL07     12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDHGT CELL07     12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDHGT CELL07     12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDWID CELL07    151.52  150.38  144.66  134.56  120.36  102.50
SO BUILDWID CELL07     81.54   58.09   32.88   58.09   81.54  102.50
SO BUILDWID CELL07    120.36  134.56  144.66  150.38  151.52  148.06
SO BUILDWID CELL07    151.52  150.38  144.66  134.56  120.36  102.50
SO BUILDWID CELL07     81.54   58.09   32.88   58.09   81.54  102.50
SO BUILDWID CELL07    120.36  134.56  144.66  150.38  151.52  148.06

SO BUILDHGT CELL08     12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDHGT CELL08     12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDHGT CELL08     12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDHGT CELL08     12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDHGT CELL08     12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDHGT CELL08     12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDWID CELL08    151.52  150.38  144.66  134.56  120.36  102.50
SO BUILDWID CELL08     81.54   58.09   32.88   58.09   81.54  102.50
SO BUILDWID CELL08    120.36  134.56  144.66  150.38  151.52  148.06
SO BUILDWID CELL08    151.52  150.38  144.66  134.56  120.36  102.50
SO BUILDWID CELL08     81.54   58.09   32.88   58.09   81.54  102.50
SO BUILDWID CELL08    120.36  134.56  144.66  150.38  151.52  148.06

SO BUILDHGT CELL09     12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDHGT CELL09     12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDHGT CELL09     12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDHGT CELL09     12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDHGT CELL09     12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDHGT CELL09     12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDWID CELL09    151.52  150.38  144.66  134.56  120.36  102.50
SO BUILDWID CELL09     81.54   58.09   32.88   58.09   81.54  102.50
SO BUILDWID CELL09    120.36  134.56  144.66  150.38  151.52  148.06
SO BUILDWID CELL09    151.52  150.38  144.66  134.56  120.36  102.50
SO BUILDWID CELL09     81.54   58.09   32.88   58.09   81.54  102.50
SO BUILDWID CELL09    120.36  134.56  144.66  150.38  151.52  148.06

SO BUILDHGT CELL10     12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDHGT CELL10     12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDHGT CELL10     12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDHGT CELL10     12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDHGT CELL10     12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDHGT CELL10     12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDWID CELL10    151.52  150.38  144.66  134.56  120.36  102.50
SO BUILDWID CELL10     81.54   58.09   32.88   58.09   81.54  102.50
SO BUILDWID CELL10    120.36  134.56  144.66  150.38  151.52  148.06
SO BUILDWID CELL10    151.52  150.38  144.66  134.56  120.36  102.50
SO BUILDWID CELL10     81.54   58.09   32.88   58.09   81.54  102.50
SO BUILDWID CELL10    120.36  134.56  144.66  150.38  151.52  148.06

SO BUILDHGT CELL11     12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDHGT CELL11     12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDHGT CELL11     12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDHGT CELL11     12.19   12.19   12.19   12.19   12.19   12.19
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SO BUILDHGT CELL11     12.19    12.19    12.19    12.19    12.19    12.19
SO BUILDHGT CELL11     12.19    12.19    12.19    12.19    12.19    12.19
SO BUILDWID CELL11    151.52   150.38   144.66   134.56   120.36   102.50
SO BUILDWID CELL11     81.54    58.09    32.88    58.09    81.54   102.50
SO BUILDWID CELL11    120.36   134.56   144.66   150.38   151.52   148.06
SO BUILDWID CELL11    151.52   150.38   144.66   134.56   120.36   102.50
SO BUILDWID CELL11     81.54    58.09    32.88    58.09    81.54   102.50
SO BUILDWID CELL11    120.36   134.56   144.66   150.38   151.52   148.06

SO BUILDHGT CELL12     12.19    12.19    12.19    12.19    12.19    12.19
SO BUILDHGT CELL12     12.19    12.19    12.19    12.19    12.19    12.19
SO BUILDHGT CELL12     12.19    12.19    12.19    12.19    12.19    12.19
SO BUILDHGT CELL12     12.19    12.19    12.19    12.19    12.19    12.19
SO BUILDHGT CELL12     12.19    12.19    12.19    12.19    12.19    12.19
SO BUILDHGT CELL12     12.19    12.19    12.19    12.19    12.19    12.19
SO BUILDWID CELL12    151.52   150.38   144.66   134.56   120.36   102.50
SO BUILDWID CELL12     81.54    58.09    32.88    58.09    81.54   102.50
SO BUILDWID CELL12    120.36   134.56   144.66   150.38   151.52   148.06
SO BUILDWID CELL12    151.52   150.38   144.66   134.56   120.36   102.50
SO BUILDWID CELL12     81.54    58.09    32.88    58.09    81.54   102.50
SO BUILDWID CELL12    120.36   134.56   144.66   150.38   151.52   148.06

SO BUILDHGT CELL13     12.19    12.19    12.19    12.19    12.19    12.19
SO BUILDHGT CELL13     12.19    12.19    12.19    12.19    12.19    12.19
SO BUILDHGT CELL13     12.19    12.19    12.19    12.19    12.19    12.19
SO BUILDHGT CELL13     12.19    12.19    12.19    12.19    12.19    12.19
SO BUILDHGT CELL13     12.19    12.19    12.19    12.19    12.19    12.19
SO BUILDHGT CELL13     12.19    12.19    12.19    12.19    12.19    12.19
SO BUILDWID CELL13    151.52   150.38   144.66   134.56   120.36   102.50
SO BUILDWID CELL13     81.54    58.09    32.88    58.09    81.54   102.50
SO BUILDWID CELL13    120.36   134.56   144.66   150.38   151.52   148.06
SO BUILDWID CELL13    151.52   150.38   144.66   134.56   120.36   102.50
SO BUILDWID CELL13     81.54    58.09    32.88    58.09    81.54   102.50
SO BUILDWID CELL13    120.36   134.56   144.66   150.38   151.52   148.06

SO BUILDHGT CELL14     12.19    12.19    12.19    12.19    12.19    12.19
SO BUILDHGT CELL14     12.19    12.19    12.19    12.19    12.19    12.19
SO BUILDHGT CELL14     12.19    12.19    12.19    12.19    12.19    12.19
SO BUILDHGT CELL14     12.19    12.19    12.19    12.19    12.19    12.19
SO BUILDHGT CELL14     12.19    12.19    12.19    12.19    12.19    12.19
SO BUILDHGT CELL14     12.19    12.19    12.19    12.19    12.19    12.19
SO BUILDWID CELL14    151.52   150.38   144.66   134.56   120.36   102.50
SO BUILDWID CELL14     81.54    58.09    32.88    58.09    81.54   102.50
SO BUILDWID CELL14    120.36   134.56   144.66   150.38   151.52   148.06
SO BUILDWID CELL14    151.52   150.38   144.66   134.56   120.36   102.50
SO BUILDWID CELL14     81.54    58.09    32.88    58.09    81.54   102.50
SO BUILDWID CELL14    120.36   134.56   144.66   150.38   151.52   148.06

SO BUILDHGT CELL15     12.19    12.19    12.19    12.19    12.19    12.19
SO BUILDHGT CELL15     12.19    12.19    12.19    12.19    12.19    12.19
SO BUILDHGT CELL15     12.19    12.19    12.19    12.19    12.19    12.19
SO BUILDHGT CELL15     12.19    12.19    12.19    12.19    12.19    12.19
SO BUILDHGT CELL15     12.19    12.19    12.19    12.19    12.19    12.19
SO BUILDHGT CELL15     12.19    12.19    12.19    12.19    12.19    12.19
SO BUILDWID CELL15    151.52   150.38   144.66   134.56   120.36   102.50
SO BUILDWID CELL15     81.54    58.09    32.88    58.09    81.54   102.50
SO BUILDWID CELL15    120.36   134.56   144.66   150.38   151.52   148.06
SO BUILDWID CELL15    151.52   150.38   144.66   134.56   120.36   102.50
SO BUILDWID CELL15     81.54    58.09    32.88    58.09    81.54   102.50
SO BUILDWID CELL15    120.36   134.56   144.66   150.38   151.52   148.06

SO BUILDHGT CELL16     12.19    12.19    12.19    12.19    12.19    12.19
SO BUILDHGT CELL16     12.19    12.19    12.19    12.19    12.19    12.19
SO BUILDHGT CELL16     12.19    12.19    12.19    12.19    12.19    12.19
SO BUILDHGT CELL16     12.19    12.19    12.19    12.19    12.19    12.19
SO BUILDHGT CELL16     12.19    12.19    12.19    12.19    12.19    12.19
SO BUILDHGT CELL16     12.19    12.19    12.19    12.19    12.19    12.19
SO BUILDWID CELL16    151.52   150.38   144.66   134.56   120.36   102.50
SO BUILDWID CELL16     81.54    58.09    32.88    58.09    81.54   102.50
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SO BUILDWID CELL16    120.36  134.56  144.66  150.38  151.52  148.06
SO BUILDWID CELL16    151.52  150.38  144.66  134.56  120.36  102.50
SO BUILDWID CELL16     81.54   58.09   32.88   58.09   81.54  102.50
SO BUILDWID CELL16    120.36  134.56  144.66  150.38  151.52  148.06

SO BUILDHGT CELL17     12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDHGT CELL17     12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDHGT CELL17     12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDHGT CELL17     12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDHGT CELL17     12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDHGT CELL17     12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDWID CELL17    151.52  150.38  144.66  134.56  120.36  102.50
SO BUILDWID CELL17     81.54   58.09   32.88   58.09   81.54  102.50
SO BUILDWID CELL17    120.36  134.56  144.66  150.38  151.52  148.06
SO BUILDWID CELL17    151.52  150.38  144.66  134.56  120.36  102.50
SO BUILDWID CELL17     81.54   58.09   32.88   58.09   81.54  102.50
SO BUILDWID CELL17    120.36  134.56  144.66  150.38  151.52  148.06

SO BUILDHGT CELL18     12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDHGT CELL18     12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDHGT CELL18     12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDHGT CELL18     12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDHGT CELL18     12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDHGT CELL18     12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDWID CELL18    151.52  150.38  144.66  134.56  120.36  102.50
SO BUILDWID CELL18     81.54   58.09   32.88   58.09   81.54  102.50
SO BUILDWID CELL18    120.36  134.56  144.66  150.38  151.52  148.06
SO BUILDWID CELL18    151.52  150.38  144.66  134.56  120.36  102.50
SO BUILDWID CELL18     81.54   58.09   32.88   58.09   81.54  102.50
SO BUILDWID CELL18    120.36  134.56  144.66  150.38  151.52  148.06
```

APPENDIX F

MODEL SUMMARY AND INPUT FILES

SIMPLE CYCLE LOAD ANALYSIS
ISCST3 SUMMARY

Table F-1. Maximum Pollutant Concentrations Predicted for One Combustion Turbine in Simple Cycle Operation

Maximum Emission Rates (lb/hr) by Operating Load and Air Inlet Temperature

Pollutant	Power Augmentation	Higher Power Mode	Baseload			75% Load			50% Load		
	80°F	95°F	95°F	59°F	35°F	95°F	59°F	35°F	95°F	59°F	35°F
Natural Gas											
Generic (9 g/s)	71.43	71.43	71.43	71.43	71.43	71.43	71.43	71.43	71.43	71.43	71.43
SO_2	9.5	9.6	8.9	9.8	10.2	7.3	7.9	8.25	5.9	6.4	6.6
PM_{10}	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
NO_x/NO_2	76.2	95.5	53.1	58.7	61.3	43.1	47.1	48.9	34.5	37.5	38.7
CO	45.0	44.7	25.5	27.5	28.6	21.7	23.5	24.4	18.3	19.5	20.1
Fuel Oil											
Generic (10 g/s)	N/A	N/A	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37
SO_2	N/A	N/A	89.1	98.6	103.1	72.2	78.8	82.0	57.7	62.6	64.7
PM_{10}	N/A	N/A	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0
NO_x/NO_2	N/A	N/A	288.2	319.2	333.8	231.2	252.6	262.6	183.2	198.9	205.6
CO	N/A	N/A	58.9	64.7	68.1	48.3	51.7	53.5	41.0	43.2	44.3

Maximum Predicted Concentrations (ug/m^3) by Operating Load and Air Inlet Temperature [a]

Pollutant	Averaging Time	Power Augmentation	Higher Power Mode	Baseload			75% Load			50% Load		
		80°F	95oF	95°F	59°F	35°F	95°F	59°F	35°F	95°F	59°F	35°F
Natural Gas												
Generic (9 g/s)	Annual	0.013	0.013	0.014	0.013	0.013	0.017	0.016	0.016	0.019	0.019	0.019
	1-Hour	1.278	1.275	1.288	1.275	1.173	2.132	2.121	2.117	2.176	2.172	2.169
	3-Hour	0.776	0.768	0.802	0.766	0.749	0.915	0.904	0.893	1.019	1.010	1.003
	8-Hour	0.428	0.428	0.440	0.428	0.427	0.526	0.508	0.500	0.597	0.590	0.585
	24-Hour	0.174	0.172	0.182	0.171	0.169	0.222	0.213	0.209	0.255	0.252	0.249
SO_2	Annual	0.0018	0.0018	0.0018	0.0018	0.0019	0.0017	0.0018	0.0019	0.0016	0.0017	0.0017
	24-Hour	0.023	0.0232	0.0226	0.0235	0.0243	0.0226	0.0236	0.0241	0.0210	0.0225	0.0230
	3-Hour	0.10	0.1034	0.0995	0.1051	0.1074	0.0934	0.1006	0.1031	0.0839	0.0903	0.0926
PM_{10}	Annual	0.0017	0.0017	0.0018	0.0017	0.0016	0.0021	0.0021	0.0020	0.0024	0.0024	0.0024
	24-Hour	0.02	0.02	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.03
NO_x/NO_2	Annual	0.014	0.018	0.011	0.011	0.011	0.010	0.011	0.011	0.009	0.010	0.0101
CO	8-Hour	0.27	0.27	0.16	0.16	0.17	0.16	0.17	0.17	0.15	0.16	0.16
	1-Hour	0.80	0.80	0.46	0.49	0.47	0.65	0.70	0.72	0.56	0.59	0.61
Fuel Oil												
Generic (10 g/s)	Annual	N/A	N/A	0.015	0.014	0.014	0.018	0.017	0.017	0.021	0.020	0.020
	1-Hour	N/A	N/A	1.375	1.302	1.270	1.754	1.607	1.589	1.936	1.888	1.871
	3-Hour	N/A	N/A	0.870	0.832	0.814	0.995	0.988	0.980	1.118	1.096	1.088
	8-Hour	N/A	N/A	0.442	0.423	0.415	0.514	0.500	0.496	0.594	0.581	0.577
	24-Hour	N/A	N/A	0.174	0.166	0.162	0.211	0.199	0.196	0.263	0.253	0.250
SO_2	Annual	N/A	N/A	0.0167	0.0173	0.0177	0.0164	0.0173	0.0178	0.0154	0.0161	0.0165
	24-Hour	N/A	N/A	0.195	0.206	0.211	0.192	0.198	0.202	0.191	0.200	0.204
	3-Hour	N/A	N/A	0.98	1.03	1.06	0.90	0.98	1.01	0.81	0.86	0.89
PM_{10}	Annual	N/A	N/A	0.0032	0.0030	0.0029	0.0039	0.0037	0.0037	0.0045	0.0044	0.0043
	24-Hour	N/A	N/A	0.04	0.04	0.03	0.05	0.04	0.04	0.06	0.05	0.05
NO_x/NO_2	Annual	N/A	N/A	0.054	0.056	0.057	0.052	0.055	0.057	0.049	0.051	0.053
CO	8-Hour	N/A	N/A	0.33	0.34	0.36	0.31	0.33	0.33	0.31	0.32	0.32
	1-Hour	N/A	N/A	1.0	1.1	1.1	1.1	1.0	1.1	1.0	1.0	1.0

[a] Concentrations are based on highest concentrations predicted using five years of meteorological data from 1987 to 1991 of surface and upper air data from the National Weather Service station at Palm Beach International Airport.

Pollutant concentrations were based on a modeled or generic concentration predicted using a modeled emission rate of 79.37 lb/hr (10 g/s). Specific pollutant concentrations were estimated by multiplying the modeled concentration (at 10 g/s) by the ratio of the specific pollutant emission rate to the modeled emission rate of 10 g/s.

SIMPLE CYCLE
NATURAL GAS
SUMMARY FILE

ISCBOB3R RELEASE 00285

ISCST3 OUTPUT FILE NUMBER 1 :SIMPLE.O87
ISCST3 OUTPUT FILE NUMBER 2 :SIMPLE.O88
ISCST3 OUTPUT FILE NUMBER 3 :SIMPLE.O89
ISCST3 OUTPUT FILE NUMBER 4 :SIMPLE.O90
ISCST3 OUTPUT FILE NUMBER 5 :SIMPLE.O91
First title for last output file is: FPL MARTIN PROPOSED SIMPLE CYCLE CTS 12/20/01
Second title for last output file is: SIGNIFICANT IMPACT ANALYSIS, SITE VICINITY, GENERIC 10G/S, N

AVERAGING TIME	YEAR	CONC (ug/m3)	X (m)	Y (m)	PERIOD ENDING (YYMMDDHH)
SOURCE GROUP ID: BASE35					
Annual					
	1987	0.01063	-7880.1	6156.6	87123124
	1988	0.01081	-17658.9	9389.4	88123124
	1989	0.01292	-7193.4	6946.6	89123124
	1990	0.01137	-17320.5	10000.0	90123124
	1991	0.01252	-7880.1	6156.6	91123124
HIGH 1-Hour					
	1987	1.13579	2309.0	1542.6	87081113
	1988	1.14432	-4921.8	937.3	88080411
	1989	1.13341	-4750.0	0.0	89041311
	1990	1.16558	2348.7	1512.9	90082313
	1991	1.17263	1785.4	2285.2	91071217
HIGH 3-Hour					
	1987	0.73268	-15760.2	12313.2	87060503
	1988	0.74148	1663.3	7825.2	88060815
	1989	0.70923	-19805.4	2783.5	89091103
	1990	0.70977	-20000.0	0.0	90031003
	1991	0.74895	6840.4	-18793.8	91011803
HIGH 8-Hour					
	1987	0.36114	-3747.5	-4922.0	87053016
	1988	0.40529	-19562.9	-4158.2	88091624
	1989	0.40320	11183.9	-16580.8	89021108
	1990	0.42661	-5624.4	1195.5	90081616
	1991	0.38116	-14862.9	13382.6	91071808
HIGH 24-Hour					
	1987	0.15596	14386.8	-13893.2	87120524
	1988	0.16272	-19696.2	3473.0	88091724
	1989	0.15069	-13382.6	14862.9	89031524
	1990	0.16948	-5624.4	1195.5	90081624
	1991	0.14936	-15320.9	12855.8	91032724
SOURCE GROUP ID: BASE59					
Annual					
	1987	0.01089	-7880.1	6156.6	87123124
	1988	0.01115	-17658.9	9389.4	88123124
	1989	0.01326	-7193.4	6946.6	89123124
	1990	0.01177	-17320.5	10000.0	90123124
	1991	0.01294	-7880.1	6156.6	91123124
HIGH 1-Hour					
	1987	1.14226	2309.0	1542.6	87081113
	1988	1.16092	-4581.3	2343.7	88071112
	1989	1.13405	-4750.0	0.0	89041311
	1990	1.27483	-1846.3	2343.7	90082412
	1991	1.20484	1723.8	2206.4	91071217
HIGH 3-Hour					
	1987	0.74940	-15760.2	12313.2	87060503
	1988	0.75107	-15760.2	12313.2	88091003
	1989	0.72423	-19805.4	2783.5	89091103
	1990	0.72466	-20000.0	0.0	90031003
	1991	0.76635	6840.4	-18793.8	91011803
HIGH 8-Hour					
	1987	0.36902	-15760.2	12313.2	87060508
	1988	0.41622	-19562.9	-4158.2	88091624
	1989	0.41297	11183.9	-16580.8	89021108
	1990	0.42776	-5624.4	1195.5	90081616
	1991	0.38960	-14862.9	13382.6	91071808
HIGH 24-Hour					
	1987	0.16048	14386.8	-13893.2	87120524
	1988	0.16649	-19696.2	3473.0	88091724
	1989	0.15569	-13382.6	14862.9	89031524

	1990	0.17104	-16961.0	10598.4	90051524
	1991	0.15291	-15320.9	12855.8	91032724
SOURCE GROUP ID:	BASE95				
Annual					
	1987	0.01146	-7880.1	6156.6	87123124
	1988	0.01191	-13244.2	7042.1	88123124
	1989	0.01421	-7193.4	6946.6	89123124
	1990	0.01259	-17320.5	10000.0	90123124
	1991	0.01378	-7880.1	6156.6	91123124
HIGH 1-Hour					
	1987	1.17775	3194.9	-57.4	87071513
	1988	1.21178	-5110.1	1288.9	88072412
	1989	1.13637	-4352.5	-2935.8	89081211
	1990	1.28844	-1846.3	2343.7	90082412
	1991	1.27346	1723.8	2206.4	91071217
HIGH 3-Hour					
	1987	0.78424	-15760.2	12313.2	87060503
	1988	0.78679	-15760.2	12313.2	88091003
	1989	0.75538	-19805.4	2783.5	89091103
	1990	0.75549	-20000.0	0.0	90031003
	1991	0.80247	6840.4	-18793.8	91011803
HIGH 8-Hour					
	1987	0.38627	-15760.2	12313.2	87060508
	1988	0.44022	-19562.9	-4158.2	88091624
	1989	0.40198	11183.9	-16580.8	89021108
	1990	0.43084	-5379.8	1143.5	90081616
	1991	0.40718	-14862.9	13382.6	91071808
HIGH 24-Hour					
	1987	0.17017	14386.8	-13893.2	87120524
	1988	0.17437	-19696.2	3473.0	88091724
	1989	0.16417	-13382.6	14862.9	89031524
	1990	0.18193	-16961.0	10598.4	90051524
	1991	0.16031	-15320.9	12855.8	91032724
SOURCE GROUP ID:	POWAUG				
Annual					
	1987	0.01103	-7880.1	6156.6	87123124
	1988	0.01136	-17658.9	9389.4	88123124
	1989	0.01346	-7193.4	6946.6	89123124
	1990	0.01203	-17320.5	10000.0	90123124
	1991	0.01312	-7880.1	6156.6	91123124
HIGH 1-Hour					
	1987	1.14566	2309.0	1542.6	87081113
	1988	1.16133	-4581.3	2343.7	88071112
	1989	1.13451	-4750.0	0.0	89041311
	1990	1.27840	-1846.3	2343.7	90082412
	1991	1.22276	1723.8	2206.4	91071217
HIGH 3-Hour					
	1987	0.75837	-15760.2	12313.2	87060503
	1988	0.76025	-15760.2	12313.2	88091003
	1989	0.73226	-19805.4	2783.5	89091103
	1990	0.73262	-20000.0	0.0	90031003
	1991	0.77567	6840.4	-18793.8	91011803
HIGH 8-Hour					
	1987	0.37346	-15760.2	12313.2	87060508
	1988	0.42219	-19562.9	-4158.2	88091624
	1989	0.41820	11183.9	-16580.8	89021108
	1990	0.42846	-5379.8	1143.5	90081616
	1991	0.39412	-14862.9	13382.6	91071808
HIGH 24-Hour					
	1987	0.16291	14386.8	-13893.2	87120524
	1988	0.16851	-19696.2	3473.0	88091724
	1989	0.15786	-13382.6	14862.9	89031524
	1990	0.17387	-16961.0	10598.4	90051524
	1991	0.15481	-15320.9	12855.8	91032724
SOURCE GROUP ID:	LD7535				
Annual					
	1987	0.01321	-7880.1	6156.6	87123124
	1988	0.01353	-13244.2	7042.1	88123124
	1989	0.01605	-7431.5	6691.3	89123124
	1990	0.01453	-17320.5	10000.0	90123124
	1991	0.01577	-7880.1	6156.6	91123124
HIGH 1-Hour					
	1987	1.66200	142.7	2343.7	87091812
	1988	1.39255	-3438.3	2498.1	88080211

	1989	1.29032	2112.6	-3973.3	89042711
	1990	2.11657	964.2	-1149.1	90072212
	1991	1.45332	1633.8	2047.0	91071217
HIGH 3-Hour					
	1987	0.87227	-15760.2	12313.2	87060503
	1988	0.87767	-15760.2	12313.2	88091003
	1989	0.83363	-19805.4	2783.5	89091103
	1990	0.83225	-20000.0	0.0	90031003
	1991	0.89280	6840.4	-18793.8	91011803
HIGH 8-Hour					
	1987	0.42990	-15760.2	12313.2	87060508
	1988	0.49995	-19562.9	-4158.2	88091624
	1989	0.42702	14694.6	-20225.4	89021108
	1990	0.47556	-15760.2	12313.2	90123024
	1991	0.45162	-14862.9	13382.6	91071808
HIGH 24-Hour					
	1987	0.20776	-11490.7	9641.8	87080724
	1988	0.20727	-19696.2	3473.0	88091724
	1989	0.18493	-13382.6	14862.9	89031524
	1990	0.20877	-16961.0	10598.4	90051524
	1991	0.18068	-13907.8	5619.1	91052124
SOURCE GROUP ID:	LD7559				
Annual					
	1987	0.01341	-7880.1	6156.6	87123124
	1988	0.01376	-13244.2	7042.1	88123124
	1989	0.01629	-7431.5	6691.3	89123124
	1990	0.01482	-17320.5	10000.0	90123124
	1991	0.01599	-7880.1	6156.6	91123124
HIGH 1-Hour					
	1987	1.66497	142.7	2343.7	87091812
	1988	1.39286	-3438.3	2498.1	88080211
	1989	1.30493	2230.0	-4194.0	89042711
	1990	2.12084	964.2	-1149.1	90072212
	1991	1.57360	1594.1	2076.7	91061812
HIGH 3-Hour					
	1987	0.88273	-15760.2	12313.2	87060503
	1988	0.88842	-15760.2	12313.2	88091003
	1989	0.84282	-19805.4	2783.5	89091103
	1990	0.84138	-20000.0	0.0	90031003
	1991	0.90376	6840.4	-18793.8	91011803
HIGH 8-Hour					
	1987	0.43509	-15760.2	12313.2	87060508
	1988	0.50768	-19562.9	-4158.2	88091624
	1989	0.43386	14694.6	-20225.4	89021108
	1990	0.48149	-15760.2	12313.2	90123024
	1991	0.45686	-14862.9	13382.6	91071808
HIGH 24-Hour					
	1987	0.20970	-11490.7	9641.8	87080724
	1988	0.20964	-19696.2	3473.0	88091724
	1989	0.18761	-13382.6	14862.9	89031524
	1990	0.21251	-16961.0	10598.4	90051524
	1991	0.18494	-13907.8	5619.1	91052124
SOURCE GROUP ID:	LD7595				
Annual					
	1987	0.01391	-7880.1	6156.6	87123124
	1988	0.01438	-13244.2	7042.1	88123124
	1989	0.01676	-7431.5	6691.3	89123124
	1990	0.01557	-17320.5	10000.0	90123124
	1991	0.01657	-7880.1	6156.6	91123124
HIGH 1-Hour					
	1987	1.67220	142.7	2343.7	87091812
	1988	1.39410	-3438.3	2498.1	88080211
	1989	1.44737	-1087.0	-4053.7	89041111
	1990	2.13163	964.2	-1149.1	90072212
	1991	1.58480	1594.1	2076.7	91061812
HIGH 3-Hour					
	1987	0.90858	-15760.2	12313.2	87060503
	1988	0.91504	-15760.2	12313.2	88091003
	1989	0.86551	-19805.4	2783.5	89091103
	1990	0.86383	-20000.0	0.0	90031003
	1991	0.90890	-14862.9	13382.6	91032124
HIGH 8-Hour					
	1987	0.44791	-15760.2	12313.2	87060508
	1988	0.52647	-19562.9	-4158.2	88091624

	1989	0.45181	11755.7	-16180.3	89021108
	1990	0.49613	-15760.2	12313.2	90123024
	1991	0.46980	-14862.9	13382.6	91071808
HIGH 24-Hour					
	1987	0.21476	-7660.4	6427.9	87080724
	1988	0.21552	-19696.2	3473.0	88091724
	1989	0.19514	-13382.6	14862.9	89031524
	1990	0.22153	-16961.0	10598.4	90051524
	1991	0.19542	-13907.8	5619.1	91052124
SOURCE GROUP ID:	LD5035				
Annual					
	1987	0.01586	-8660.3	5000.0	87123124
	1988	0.01640	-13244.2	7042.1	88123124
	1989	0.01868	-7880.1	6156.6	89123124
	1990	0.01814	-12990.4	7500.0	90123124
	1991	0.01842	-7880.1	6156.6	91123124
HIGH 1-Hour					
	1987	1.70208	142.7	2343.7	87091812
	1988	1.51505	-3785.6	2343.7	88083111
	1989	1.69107	-1863.1	3819.9	89062811
	1990	2.16910	964.2	-1149.1	90072212
	1991	1.70497	1633.8	2047.0	91071217
HIGH 3-Hour					
	1987	0.99324	-15760.2	12313.2	87060503
	1988	1.00283	-15760.2	12313.2	88091003
	1989	0.94477	-14854.0	2087.6	89091103
	1990	0.94661	-15000.0	0.0	90031003
	1991	0.98940	-14862.9	13382.6	91032124
HIGH 8-Hour					
	1987	0.49027	-16961.0	10598.4	87062008
	1988	0.58505	-19562.9	-4158.2	88091624
	1989	0.51800	11755.7	-16180.3	89021108
	1990	0.54412	-15760.2	12313.2	90123024
	1991	0.52501	-4728.1	3694.0	91072416
HIGH 24-Hour					
	1987	0.23379	-7660.4	6427.9	87080724
	1988	0.23491	-19696.2	3473.0	88091724
	1989	0.21563	-13382.6	14862.9	89031524
	1990	0.24900	-16961.0	10598.4	90051524
	1991	0.22936	-13907.8	5619.1	91052124
SOURCE GROUP ID:	LD5059				
Annual					
	1987	0.01605	-8660.3	5000.0	87123124
	1988	0.01659	-13244.2	7042.1	88123124
	1989	0.01885	-7880.1	6156.6	89123124
	1990	0.01837	-12990.4	7500.0	90123124
	1991	0.01865	-13244.2	7042.1	91123124
HIGH 1-Hour					
	1987	1.70520	142.7	2343.7	87091812
	1988	1.51566	-3785.6	2343.7	88083111
	1989	1.69112	-1863.1	3819.9	89062811
	1990	2.17220	964.2	-1149.1	90072212
	1991	1.71962	1633.8	2047.0	91071217
HIGH 3-Hour					
	1987	1.00024	-15760.2	12313.2	87060503
	1988	1.01004	-15760.2	12313.2	88091003
	1989	0.95185	-14854.0	2087.6	89091103
	1990	0.95372	-15000.0	0.0	90031003
	1991	0.99610	-14862.9	13382.6	91032124
HIGH 8-Hour					
	1987	0.49616	-16961.0	10598.4	87062008
	1988	0.59038	-19562.9	-4158.2	88091624
	1989	0.52532	11755.7	-16180.3	89021108
	1990	0.54813	-15760.2	12313.2	90123024
	1991	0.52871	-4531.1	3540.1	91072416
HIGH 24-Hour					
	1987	0.23540	-7660.4	6427.9	87080724
	1988	0.23650	-19696.2	3473.0	88091724
	1989	0.21752	-13382.6	14862.9	89031524
	1990	0.25168	-16961.0	10598.4	90051524
	1991	0.23226	-13907.8	5619.1	91052124
SOURCE GROUP ID:	LD5095				
Annual					
	1987	0.01633	-8660.3	5000.0	87123124

	1988	0.01684	-13244.2	7042.1	88123124
	1989	0.01907	-7880.1	6156.6	89123124
	1990	0.01864	-12990.4	7500.0	90123124
	1991	0.01893	-13244.2	7042.1	91123124
HIGH 1-Hour					
	1987	1.70904	142.7	2343.7	87091812
	1988	1.51645	-3785.6	2343.7	88083111
	1989	1.69124	-1863.1	3819.9	89062811
	1990	2.17607	964.2	-1149.1	90072212
	1991	1.73691	1633.8	2047.0	91071217
HIGH 3-Hour					
	1987	1.00884	-15760.2	12313.2	87060503
	1988	1.01893	-15760.2	12313.2	88091003
	1989	0.96055	-14854.0	2087.6	89091103
	1990	0.96238	-15000.0	0.0	90031003
	1991	1.00427	-14862.9	13382.6	91032124
HIGH 8-Hour					
	1987	0.50290	-16961.0	10598.4	87062008
	1988	0.59665	-19562.9	-4158.2	88091624
	1989	0.53370	11755.7	-16180.3	89021108
	1990	0.55302	-15760.2	12313.2	90123024
	1991	0.53340	-4531.1	3540.1	91072416
HIGH 24-Hour					
	1987	0.23740	-7660.4	6427.9	87080724
	1988	0.23847	-19696.2	3473.0	88091724
	1989	0.21983	-13382.6	14862.9	89031524
	1990	0.25475	-16961.0	10598.4	90051524
	1991	0.23574	-13907.8	5619.1	91052124

All receptor computations reported with respect to a user-specified origin

GRID	0.00	0.00
DISCRETE	0.00	0.00

SIMPLE CYCLE
HIGHER POWER MODE
SUMMARY FILE

ISCBOB3R RELEASE 00285

ISCST3 OUTPUT FILE NUMBER 1 :SIMPLE.087
ISCST3 OUTPUT FILE NUMBER 2 :SIMPLE.088
ISCST3 OUTPUT FILE NUMBER 3 :SIMPLE.089
ISCST3 OUTPUT FILE NUMBER 4 :SIMPLE.090
ISCST3 OUTPUT FILE NUMBER 5 :SIMPLE.091
First title for last output file is: FPL MARTIN PROPOSED SIMPLE CYCLE CTS 12/20/01
Second title for last output file is: SIGNIFICANT IMPACT ANALYSIS, SITE VICINITY, GENERIC 10G/S, N

AVERAGING TIME	YEAR	CONC (ug/m3)	X (m)	Y (m)	PERIOD ENDING (YYMMDDHH)
SOURCE GROUP ID:	HPM35				
Annual					
	1987	0.01044	-7880.1	6156.6	87123124
	1988	0.01062	-17658.9	9389.4	88123124
	1989	0.01260	-7193.4	6946.6	89123124
	1990	0.01114	-17320.5	10000.0	90123124
	1991	0.01231	-7880.1	6156.6	91123124
HIGH 1-Hour					
	1987	1.13127	2309.0	1542.6	87081113
	1988	1.10051	-1309.3	-4566.0	88042811
	1989	1.09969	-4608.9	-1149.1	89051614
	1990	1.16097	2348.7	1512.9	90082313
	1991	1.15197	1785.4	2285.2	91071217
HIGH 3-Hour					
	1987	0.72190	1403.4	-6602.5	87102612
	1988	0.74034	1663.3	7825.2	88060815
	1989	0.69922	-19805.4	2783.5	89091103
	1990	0.69998	-20000.0	0.0	90031003
	1991	0.73770	6840.4	-18793.8	91011803
HIGH 8-Hour					
	1987	0.35617	-3747.5	-4922.0	87053016
	1988	0.39839	-19562.9	-4158.2	88091624
	1989	0.39694	11183.9	-16580.8	89021108
	1990	0.42589	-5624.4	1195.5	90081616
	1991	0.37552	-14862.9	13382.6	91071808
HIGH 24-Hour					
	1987	0.15805	14386.8	-13893.2	87120524
	1988	0.16020	-19696.2	3473.0	88091724
	1989	0.14804	-13382.6	14862.9	89031524
	1990	0.16886	-5624.4	1195.5	90081624
	1991	0.14702	-15320.9	12855.8	91032724
SOURCE GROUP ID:	HPM59				
Annual					
	1987	0.01067	-7880.1	6156.6	87123124
	1988	0.01085	-17658.9	9389.4	88123124
	1989	0.01297	-7193.4	6946.6	89123124
	1990	0.01142	-17320.5	10000.0	90123124
	1991	0.01265	-7880.1	6156.6	91123124
HIGH 1-Hour					
	1987	1.13672	2309.0	1542.6	87081113
	1988	1.14444	-4921.8	937.3	88080411
	1989	1.13349	-4750.0	0.0	89041311
	1990	1.16655	2348.7	1512.9	90082313
	1991	1.17895	1785.4	2285.2	91071217
HIGH 3-Hour					
	1987	0.73546	-15760.2	12313.2	87060503
	1988	0.74176	1663.3	7825.2	88060815
	1989	0.71166	-19805.4	2783.5	89091103
	1990	0.71237	-20000.0	0.0	90031003
	1991	0.75218	6840.4	-18793.8	91011803
HIGH 8-Hour					
	1987	0.36261	-3747.5	-4922.0	87053016
	1988	0.40750	-19562.9	-4158.2	88091624
	1989	0.40508	11183.9	-16580.8	89021108
	1990	0.42678	-5624.4	1195.5	90081616
	1991	0.38251	-14862.9	13382.6	91071808
HIGH 24-Hour					
	1987	0.15713	14386.8	-13893.2	87120524
	1988	0.16332	-19696.2	3473.0	88091724
	1989	0.15139	-13382.6	14862.9	89031524

	1990	0.16939	-5624.4	1195.5	90081624
	1991	0.14997	-15320.9	12855.8	91032724
SOURCE GROUP ID:	HPM95				
Annual					
	1987	0.01091	-7880.1	6156.6	87123124
	1988	0.01125	-17658.9	9389.4	88123124
	1989	0.01328	-7193.4	6946.6	89123124
	1990	0.01183	-17320.5	10000.0	90123124
	1991	0.01296	-7880.1	6156.6	91123124
HIGH 1-Hour					
	1987	1.14262	2309.0	1542.6	87081113
	1988	1.16097	-4581.3	2343.7	88071112
	1989	1.13411	-4750.0	0.0	89041311
	1990	1.27524	-1846.3	2343.7	90082412
	1991	1.20910	1723.8	2206.4	91071217
HIGH 3-Hour					
	1987	0.75087	-15760.2	12313.2	87060503
	1988	0.75242	-15760.2	12313.2	88091003
	1989	0.72546	-19805.4	2783.5	89091103
	1990	0.72613	-20000.0	0.0	90031003
	1991	0.76833	6840.4	-18793.8	91011803
HIGH 8-Hour					
	1987	0.36975	-15760.2	12313.2	87060508
	1988	0.41802	-19562.9	-4158.2	88091624
	1989	0.41416	11183.9	-16580.8	89021108
	1990	0.42785	-5624.4	1195.5	90081616
	1991	0.39028	-14862.9	13382.6	91071808
HIGH 24-Hour					
	1987	0.16154	14386.8	-13893.2	87120524
	1988	0.16679	-19696.2	3473.0	88091724
	1989	0.15608	-13382.6	14862.9	89031524
	1990	0.17223	-16961.0	10598.4	90051524
	1991	0.15324	-15320.9	12855.8	91032724

All receptor computations reported with respect to a user-specified origin

GRID	0.00	0.00
DISCRETE	0.00	0.00

SIMPLE CYCLE
FUEL OIL
SUMMARY FILE

ISCBOB3R RELEASE 00285

ISCST3 OUTPUT FILE NUMBER 1 :SIMPLE.087
ISCST3 OUTPUT FILE NUMBER 2 :SIMPLE.088
ISCST3 OUTPUT FILE NUMBER 3 :SIMPLE.089
ISCST3 OUTPUT FILE NUMBER 4 :SIMPLE.090
ISCST3 OUTPUT FILE NUMBER 5 :SIMPLE.091
First title for last output file is: FPL MARTIN PROPOSED SIMPLE CYCLE CTS 12/20/01
Second title for last output file is: SIGNIFICANT IMPACT ANALYSIS, SITE VICINITY, GENERIC 10G/S, F

AVERAGING TIME	YEAR	CONC (ug/m3)	X (m)	Y (m)	PERIOD ENDING (YYMMDDHH)
SOURCE GROUP ID: BASE35					
Annual					
	1987	0.01156	-7880.1	6156.6	87123124
	1988	0.01197	-13244.2	7042.1	88123124
	1989	0.01391	-7193.4	6946.6	89123124
	1990	0.01235	-17320.5	10000.0	90123124
	1991	0.01359	-7880.1	6156.6	91123124
HIGH 1-Hour					
	1987	1.25527	2309.0	1542.6	87081113
	1988	1.22266	-1309.3	-4566.0	88042811
	1989	1.22173	-4608.9	-1149.1	89051614
	1990	1.28822	2348.7	1512.9	90082313
	1991	1.27033	1785.4	2285.2	91071217
HIGH 3-Hour					
	1987	0.80164	1403.4	-6602.5	87102612
	1988	0.82219	1663.3	7825.2	88060815
	1989	0.77279	-19805.4	2783.5	89091103
	1990	0.77345	-20000.0	0.0	90031003
	1991	0.81445	6840.4	-18793.8	91011803
HIGH 8-Hour					
	1987	0.39335	-3747.5	-4922.0	87053016
	1988	0.44137	1767.3	8314.3	88060816
	1989	0.43805	11183.9	-16580.8	89021108
	1990	0.47283	-5624.4	1195.5	90081616
	1991	0.41494	-14862.9	13382.6	91071808
HIGH 24-Hour					
	1987	0.17392	14386.8	-13893.2	87120524
	1988	0.17697	-19696.2	3473.0	88091724
	1989	0.16334	-13382.6	14862.9	89031524
	1990	0.18734	-5624.4	1195.5	90081624
	1991	0.16235	-15320.9	12855.8	91032724
SOURCE GROUP ID: BASE59					
Annual					
	1987	0.01180	-7880.1	6156.6	87123124
	1988	0.01200	-17658.9	9389.4	88123124
	1989	0.01435	-7193.4	6946.6	89123124
	1990	0.01262	-17320.5	10000.0	90123124
	1991	0.01391	-7880.1	6156.6	91123124
HIGH 1-Hour					
	1987	1.26179	2309.0	1542.6	87081113
	1988	1.27144	-4921.8	937.3	88080411
	1989	1.25933	-4750.0	0.0	89041311
	1990	1.29489	2348.7	1512.9	90082313
	1991	1.30211	1785.4	2285.2	91071217
HIGH 3-Hour					
	1987	0.81363	-15760.2	12313.2	87060503
	1988	0.82381	1663.3	7825.2	88060815
	1989	0.78762	-19805.4	2783.5	89091103
	1990	0.78823	-20000.0	0.0	90031003
	1991	0.83171	6840.4	-18793.8	91011803
HIGH 8-Hour					
	1987	0.40107	-3747.5	-4922.0	87053016
	1988	0.45006	-19562.9	-4158.2	88091624
	1989	0.44775	11183.9	-16580.8	89021108
	1990	0.47398	-5624.4	1195.5	90081616
	1991	0.42327	-14862.9	13382.6	91071808
HIGH 24-Hour					
	1987	0.17320	14386.8	-13893.2	87120524
	1988	0.18069	-19696.2	3473.0	88091724
	1989	0.16732	-13382.6	14862.9	89031524

	1990	0.18829	-5624.4	1195.5	90081624
	1991	0.16586	-15320.9	12855.8	91032724
SOURCE GROUP ID:	BASE95				
Annual					
	1987	0.01239	-7880.1	6156.6	87123124
	1988	0.01283	-13244.2	7042.1	88123124
	1989	0.01522	-7193.4	6946.6	89123124
	1990	0.01354	-17320.5	10000.0	90123124
	1991	0.01491	-7880.1	6156.6	91123124
HIGH 1-Hour					
	1987	1.27650	3194.9	-57.4	87071513
	1988	1.34499	-5110.1	1288.9	88072412
	1989	1.26105	-4750.0	0.0	89041311
	1990	1.42366	-1846.3	2343.7	90082412
	1991	1.37488	1723.8	2206.4	91071217
HIGH 3-Hour					
	1987	0.85083	-15760.2	12313.2	87060503
	1988	0.85312	-15760.2	12313.2	88091003
	1989	0.82095	-19805.4	2783.5	89091103
	1990	0.82129	-20000.0	0.0	90031003
	1991	0.87038	6840.4	-18793.8	91011803
HIGH 8-Hour					
	1987	0.41902	-15760.2	12313.2	87060508
	1988	0.47486	-19562.9	-4158.2	88091624
	1989	0.44247	11755.7	-16180.3	89021108
	1990	0.47680	-5379.8	1143.5	90081616
	1991	0.44205	-14862.9	13382.6	91071808
HIGH 24-Hour					
	1987	0.18337	14386.8	-13893.2	87120524
	1988	0.18909	-19696.2	3473.0	88091724
	1989	0.17739	-13382.6	14862.9	89031524
	1990	0.19578	-16961.0	10598.4	90051524
	1991	0.17376	-15320.9	12855.8	91032724
SOURCE GROUP ID:	LD7535				
Annual					
	1987	0.01446	-7880.1	6156.6	87123124
	1988	0.01469	-13244.2	7042.1	88123124
	1989	0.01756	-7431.5	6691.3	89123124
	1990	0.01584	-17320.5	10000.0	90123124
	1991	0.01726	-7880.1	6156.6	91123124
HIGH 1-Hour					
	1987	1.43842	3194.9	-57.4	87071513
	1988	1.46769	-3344.1	3011.1	88080911
	1989	1.43282	2112.6	-3973.3	89042711
	1990	2.34681	964.2	-1149.1	90072212
	1991	1.58904	1662.3	2127.6	91071217
HIGH 3-Hour					
	1987	0.95715	-15760.2	12313.2	87060503
	1988	0.96276	-15760.2	12313.2	88091003
	1989	0.91562	-19805.4	2783.5	89091103
	1990	0.91427	-20000.0	0.0	90031003
	1991	0.97959	6840.4	-18793.8	91011803
HIGH 8-Hour					
	1987	0.47170	-15760.2	12313.2	87060508
	1988	0.54714	-19562.9	-4158.2	88091624
	1989	0.49980	11183.9	-16580.8	89021108
	1990	0.52160	-15760.2	12313.2	90123024
	1991	0.49574	-14862.9	13382.6	91071808
HIGH 24-Hour					
	1987	0.22861	-11490.7	9641.8	87080724
	1988	0.22756	-19696.2	3473.0	88091724
	1989	0.20242	-13382.6	14862.9	89031524
	1990	0.22807	-16961.0	10598.4	90051524
	1991	0.19598	-13907.8	5619.1	91052124
SOURCE GROUP ID:	LD7559				
Annual					
	1987	0.01461	-7880.1	6156.6	87123124
	1988	0.01497	-13244.2	7042.1	88123124
	1989	0.01774	-7431.5	6691.3	89123124
	1990	0.01604	-17320.5	10000.0	90123124
	1991	0.01743	-7880.1	6156.6	91123124
HIGH 1-Hour					
	1987	1.84548	142.7	2343.7	87091812
	1988	1.54719	-3438.3	2498.1	88080211

	1989	1.43339	2112.6	-3973.3	89042711
	1990	2.35005	964.2	-1149.1	90072212
	1991	1.60747	1633.8	2047.0	91071217
HIGH 3-Hour					
	1987	0.96527	-15760.2	12313.2	87060503
	1988	0.97107	-15760.2	12313.2	88091003
	1989	0.92275	-19805.4	2783.5	89091103
	1990	0.92139	-20000.0	0.0	90031003
	1991	0.98815	6840.4	-18793.8	91011803
HIGH 8-Hour					
	1987	0.47572	-15760.2	12313.2	87060508
	1988	0.55329	-19562.9	-4158.2	88091624
	1989	0.47252	14694.6	-20225.4	89021108
	1990	0.52620	-15760.2	12313.2	90123024
	1991	0.49980	-14862.9	13382.6	91071808
HIGH 24-Hour					
	1987	0.23010	-11490.7	9641.8	87080724
	1988	0.22939	-19696.2	3473.0	88091724
	1989	0.20450	-13382.6	14862.9	89031524
	1990	0.23110	-16961.0	10598.4	90051524
	1991	0.19931	-13907.8	5619.1	91052124
SOURCE GROUP ID:	LD7595				
Annual					
	1987	0.01506	-7880.1	6156.6	87123124
	1988	0.01559	-13244.2	7042.1	88123124
	1989	0.01824	-7431.5	6691.3	89123124
	1990	0.01684	-17320.5	10000.0	90123124
	1991	0.01800	-7880.1	6156.6	91123124
HIGH 1-Hour					
	1987	1.85349	142.7	2343.7	87091812
	1988	1.54813	-3438.3	2498.1	88080211
	1989	1.45092	2230.0	-4194.0	89042711
	1990	2.36165	964.2	-1149.1	90072212
	1991	1.75391	1594.1	2076.7	91061812
HIGH 3-Hour					
	1987	0.99345	-15760.2	12313.2	87060503
	1988	1.00008	-15760.2	12313.2	88091003
	1989	0.94753	-19805.4	2783.5	89091103
	1990	0.94591	-20000.0	0.0	90031003
	1991	0.99451	-14862.9	13382.6	91032124
HIGH 8-Hour					
	1987	0.48970	-15760.2	12313.2	87060508
	1988	0.57372	-19562.9	-4158.2	88091624
	1989	0.49069	14694.6	-20225.4	89021108
	1990	0.54215	-15760.2	12313.2	90123024
	1991	0.51392	-14862.9	13382.6	91071808
HIGH 24-Hour					
	1987	0.23535	-11490.7	9641.8	87080724
	1988	0.23580	-19696.2	3473.0	88091724
	1989	0.21270	-13382.6	14862.9	89031524
	1990	0.24088	-16961.0	10598.4	90051524
	1991	0.21071	-13907.8	5619.1	91052124
SOURCE GROUP ID:	LD5035				
Annual					
	1987	0.01725	-12990.4	7500.0	87123124
	1988	0.01794	-13244.2	7042.1	88123124
	1989	0.02045	-7660.4	6427.9	89123124
	1990	0.01981	-12990.4	7500.0	90123124
	1991	0.02027	-7880.1	6156.6	91123124
HIGH 1-Hour					
	1987	1.88566	142.7	2343.7	87091812
	1988	1.68239	-3785.6	2343.7	88083111
	1989	1.68677	3200.0	-456.2	89052111
	1990	2.40465	964.2	-1149.1	90072212
	1991	1.87073	1633.8	2047.0	91071217
HIGH 3-Hour					
	1987	1.09156	-15760.2	12313.2	87060503
	1988	1.10175	-15760.2	12313.2	88091003
	1989	1.03754	-14854.0	2087.6	89091103
	1990	1.03975	-15000.0	0.0	90031003
	1991	1.08792	-14862.9	13382.6	91032124
HIGH 8-Hour					
	1987	0.53838	-15760.2	12313.2	87060508
	1988	0.64172	-19562.9	-4158.2	88091624

	1989	0.56606	11755.7	-16180.3	89021108
	1990	0.59774	-15760.2	12313.2	90123024
	1991	0.57701	-4728.1	3694.0	91072416
HIGH 24-Hour					
	1987	0.25698	-7660.4	6427.9	87080724
	1988	0.25825	-19696.2	3473.0	88091724
	1989	0.23639	-13382.6	14862.9	89031524
	1990	0.27274	-16961.0	10598.4	90051524
	1991	0.25005	-13907.8	5619.1	91052124
SOURCE GROUP ID:	LD5059				
Annual					
	1987	0.01754	-12990.4	7500.0	87123124
	1988	0.01815	-13244.2	7042.1	88123124
	1989	0.02065	-7880.1	6156.6	89123124
	1990	0.02006	-12990.4	7500.0	90123124
	1991	0.02038	-7880.1	6156.6	91123124
HIGH 1-Hour					
	1987	1.88931	142.7	2343.7	87091812
	1988	1.68304	-3785.6	2343.7	88083111
	1989	1.87895	-1863.1	3819.9	89062811
	1990	2.40822	964.2	-1149.1	90072212
	1991	1.88759	1633.8	2047.0	91071217
HIGH 3-Hour					
	1987	1.09963	-15760.2	12313.2	87060503
	1988	1.11007	-15760.2	12313.2	88091003
	1989	1.04568	-14854.0	2087.6	89091103
	1990	1.04790	-15000.0	0.0	90031003
	1991	1.09562	-14862.9	13382.6	91032124
HIGH 8-Hour					
	1987	0.54276	-16961.0	10598.4	87062008
	1988	0.64778	-19562.9	-4158.2	88091624
	1989	0.57345	11755.7	-16180.3	89021108
	1990	0.60234	-15760.2	12313.2	90123024
	1991	0.58117	-4728.1	3694.0	91072416
HIGH 24-Hour					
	1987	0.25883	-7660.4	6427.9	87080724
	1988	0.26009	-19696.2	3473.0	88091724
	1989	0.23855	-13382.6	14862.9	89031524
	1990	0.27576	-16961.0	10598.4	90051524
	1991	0.25337	-13907.8	5619.1	91052124
SOURCE GROUP ID:	LD5095				
Annual					
	1987	0.01822	-8660.3	5000.0	87123124
	1988	0.01879	-13244.2	7042.1	88123124
	1989	0.02129	-7880.1	6156.6	89123124
	1990	0.02080	-12990.4	7500.0	90123124
	1991	0.02116	-13244.2	7042.1	91123124
HIGH 1-Hour					
	1987	1.90014	142.7	2343.7	87091812
	1988	1.68521	-3785.6	2343.7	88083111
	1989	1.87921	-1863.1	3819.9	89062811
	1990	2.41909	964.2	-1149.1	90072212
	1991	1.93556	1633.8	2047.0	91071217
HIGH 3-Hour					
	1987	1.12369	-15760.2	12313.2	87060503
	1988	1.13498	-15760.2	12313.2	88091003
	1989	1.07006	-14854.0	2087.6	89091103
	1990	1.07211	-15000.0	0.0	90031003
	1991	1.11849	-14862.9	13382.6	91032124
HIGH 8-Hour					
	1987	0.56107	-16961.0	10598.4	87062008
	1988	0.66502	-19562.9	-4158.2	88091624
	1989	0.59592	11755.7	-16180.3	89021108
	1990	0.61604	-15760.2	12313.2	90123024
	1991	0.59415	-4531.1	3540.1	91072416
HIGH 24-Hour					
	1987	0.26442	-7660.4	6427.9	87080724
	1988	0.26560	-19696.2	3473.0	88091724
	1989	0.24500	-13382.6	14862.9	89031524
	1990	0.28410	-16961.0	10598.4	90051524
	1991	0.26306	-13907.8	5619.1	91052124

All receptor computations reported with respect to a user-specified origin

GRID	0.00	0.00
DISCRETE	0.00	0.00

COMBINED CYCLE LOAD ANALYSIS
ISCST3 SUMMARY

Table F-2. Maximum Pollutant Concentrations Predicted for One Combustion Turbine in Combined Cycle Operation

	Maximum Emission Rates (lb/hr) by Operating Load and Air Inlet Temperature											Maximum Predicted Concentrations (ug/m^3) by Operating Load and Air Inlet Temperature [a]						
	Power Augmentation	Baseload			75% Load			50% Load			Averaging	Power Augmentation	Baseload			75% Load		
Pollutant	80°F	95°F	59°F	35°F	95°F	59°F	35°F	95°F	59°F	35°F	Time	80°F	95°F	59°F	35°F	95°F	59°F	35°F
Natural Gas [b]																		
Generic (9 g/s)	71.43	71.43	71.43	71.43	71.43	71.43	71.43	71.43	71.43	71.43	Annual	0.158	0.196	0.178	0.167	0.257	0.239	0.236
											1-Hour	7.805	8.064	8.068	7.799	10.155	10.144	10.146
											3-Hour	4.896	5.609	5.364	5.185	6.797	6.443	6.383
											8-Hour	3.257	3.943	3.633	3.427	4.928	4.667	4.623
											24-Hour	2.277	2.638	2.476	2.364	3.155	2.988	2.965
SO_2	12.5	11.9	12.8	13.3	7.3	7.9	8.3	5.9	6.4	6.6	Annual	0.0277	0.0326	0.0319	0.0310	0.0262	0.0266	0.0273
											24-Hour	0.400	0.439	0.445	0.440	0.322	0.333	0.342
											3-Hour	0.86	0.93	0.96	0.96	0.69	0.72	0.74
PM_{10}	17.0	16.9	17.1	17.2	10.5	10.6	10.7	10.2	10.3	10.3	Annual	0.0377	0.0463	0.0425	0.0401	0.0377	0.0355	0.0353
											24-Hour	0.54	0.62	0.59	0.57	0.46	0.44	0.44
NO_x/ NO_2	30.9	31.2	33.1	33.9	16.8	18.3	19.0	13.4	14.6	15.1	Annual	0.068	0.086	0.082	0.079	0.060	0.061	0.063
CO	89.0	69.5	71.5	72.6	21.7	23.5	24.4	18.3	19.5	20.1	8-Hour	4.06	3.84	3.64	3.49	1.50	1.54	1.58
											1-Hour	9.72	7.85	8.08	7.93	3.08	3.34	3.46
Fuel Oil																		
Generic (9 g/s)		71.43	71.43	71.43	71.43	71.43	71.43	71.43	71.43	71.43	Annual	NA	0.079	0.070	0.065	0.120	0.114	0.110
											1-Hour	NA	5.309	5.246	5.214	6.013	6.011	6.011
											3-Hour	NA	2.889	2.644	2.522	3.912	3.782	3.710
											8-Hour	NA	2.068	1.856	1.734	2.687	2.615	2.575
											24-Hour	NA	1.336	1.198	1.119	1.834	1.751	1.705
SO_2		89.1	98.6	103.1	72.2	78.8	82.0	57.7	62.6	64.7	Annual	NA	0.0991	0.0968	0.0943	0.1212	0.1255	0.1268
											24-Hour	NA	1.667	1.654	1.616	1.852	1.931	1.957
											3-Hour	NA	3.60	3.65	3.64	3.95	4.17	4.26
PM_{10}		35.0	36.9	37.8	31.6	32.9	33.6	28.7	29.7	30.1	Annual	NA	0.0390	0.0362	0.0346	0.0530	0.0524	0.0519
											24-Hour	NA	0.65	0.62	0.59	0.81	0.81	0.80
NO_x/ NO_2		82.3	91.2	95.4	66.1	72.2	75.0	52.3	56.8	58.7	Annual	NA	0.092	0.090	0.087	0.111	0.115	0.116
CO		58.9	64.7	68.1	48.3	51.7	53.5	41.0	43.2	44.3	8-Hour	NA	1.70	1.68	1.65	1.82	1.89	1.93
											1-Hour	NA	4.4	4.7	5.0	4.1	4.4	4.5

[a] Concentrations are based on highest concentrations predicted using five years of meteorological data from 1987 to 1991 of surface and upper air data from the National Weather Service station at Palm Beach International Airport.

Pollutant concentrations were based on a modeled or generic concentration predicted using a modeled emission rate of 79.37 lb/hr (10 g/s). Specific pollutant concentrations were estimated by multiplying the modeled concentration (at 10 g/s) by the ratio of the specific pollutant emission rate to the modeled emission rate of 10 g/s.

[b] Duct firing included for baseload operating load. Duct firing based on natural gas-fired duct burner with maximum heat input rate of 550 mmBtu/hr (HHV).

COMBINED CYCLE
NATURAL GAS
SUMMARY FILE

ISCBOB3R RELEASE 00285

ISCST3 OUTPUT FILE NUMBER 1 :COMBINED.087
ISCST3 OUTPUT FILE NUMBER 2 :COMBINED.088
ISCST3 OUTPUT FILE NUMBER 3 :COMBINED.089
ISCST3 OUTPUT FILE NUMBER 4 :COMBINED.090
ISCST3 OUTPUT FILE NUMBER 5 :COMBINED.091
First title for last output file is: FPL MARTIN PROPOSED COMBINED CYCLE CTS 12/20/01
Second title for last output file is: SIGNIFICANT IMPACT ANALYSIS, SITE VICINITY, GENERIC 10G/S, N

AVERAGING TIME	YEAR	CONC (ug/m3)	X (m)	Y (m)	PERIOD ENDING (YYMMDDHH)
SOURCE GROUP ID:	BSDB35				
Annual					
	1987	0.13567	-4034.3	2343.7	87123124
	1988	0.12910	-4497.9	146.1	88123124
	1989	0.14392	-2194.4	2343.7	89123124
	1990	0.16678	-4084.0	2343.7	90123124
	1991	0.15599	-4183.5	2343.7	91123124
HIGH 1-Hour					
	1987	7.28355	-4035.8	-1876.0	87092608
	1988	7.54417	-2940.3	2343.7	88100208
	1989	7.22362	744.6	-877.3	89092113
	1990	7.79895	-4680.7	2343.7	90071713
	1991	7.19051	2587.0	1334.9	91030916
HIGH 3-Hour					
	1987	4.84497	2110.4	1690.9	87062712
	1988	4.81775	1765.9	-938.9	88042712
	1989	4.16450	-2343.6	2343.7	89060515
	1990	4.48792	-3993.3	-2120.9	90100812
	1991	5.18460	2428.2	1453.6	91060212
HIGH 8-Hour					
	1987	3.42671	2070.7	1720.6	87062716
	1988	3.21197	-4265.2	-553.4	88013008
	1989	2.77621	-4163.2	-1141.2	89072516
	1990	3.25439	-4146.2	-1239.2	90030816
	1991	3.15764	-5416.2	1860.3	91052124
HIGH 24-Hour					
	1987	2.36438	-4403.8	-29.7	87111624
	1988	2.08784	-4248.2	-651.4	88013024
	1989	1.44017	-3638.7	3053.2	89040424
	1990	2.22336	-1746.9	2343.7	90101024
	1991	2.06754	-5277.4	2343.7	91052124
SOURCE GROUP ID:	BSDB59				
Annual					
	1987	0.14457	-4034.3	2343.7	87123124
	1988	0.13656	-4474.4	102.2	88123124
	1989	0.15307	-3686.2	2343.7	89123124
	1990	0.17777	-4034.3	2343.7	90123124
	1991	0.16576	-4183.5	2343.7	91123124
HIGH 1-Hour					
	1987	7.46932	2901.6	-1957.2	87102808
	1988	7.55581	-2940.3	2343.7	88100208
	1989	7.48286	744.6	-877.3	89092113
	1990	8.06768	-1408.4	2648.8	90050507
	1991	7.43920	2220.9	-863.9	91021514
HIGH 3-Hour					
	1987	5.03244	2110.4	1690.9	87062712
	1988	5.04629	1765.9	-938.9	88042712
	1989	4.31987	-2343.6	2343.7	89060515
	1990	4.72015	-3993.3	-2120.9	90100812
	1991	5.36446	2428.2	1453.6	91060212
HIGH 8-Hour					
	1987	3.63269	2070.7	1720.6	87062716
	1988	3.38747	-4265.2	-553.4	88013008
	1989	2.90578	-4163.2	-1141.2	89072516
	1990	3.39754	-4146.2	-1239.2	90030816
	1991	3.24365	-5416.2	1860.3	91052124
HIGH 24-Hour					
	1987	2.47604	-4403.8	-29.7	87111624
	1988	2.19633	-4248.2	-651.4	88013024
	1989	1.54798	-3447.2	2892.5	89040424

	1990	2.34708	-1746.9	2343.7	90101024
	1991	2.12633	-5277.4	2343.7	91052124
SOURCE GROUP ID:	BSDB95				
Annual					
	1987	0.15955	-3984.6	2343.7	87123124
	1988	0.14966	-4450.9	58.2	88123124
	1989	0.16890	-2194.4	2343.7	89123124
	1990	0.19569	-4034.3	2343.7	90123124
	1991	0.18075	-4133.7	2343.7	91123124
HIGH 1-Hour					
	1987	7.70190	2110.4	1690.9	87012212
	1988	7.57573	-2940.3	2343.7	88100208
	1989	7.96845	744.6	-877.3	89092113
	1990	8.06396	-1408.4	2648.8	90050507
	1991	7.97361	2220.9	-863.9	91021514
HIGH 3-Hour					
	1987	5.30467	2110.4	1690.9	87062712
	1988	5.41623	2070.7	1720.6	88110512
	1989	4.54706	-2343.6	2343.7	89060515
	1990	5.05213	-3993.3	-2120.9	90100812
	1991	5.60884	2428.2	1453.6	91060212
HIGH 8-Hour					
	1987	3.94310	2070.7	1720.6	87062716
	1988	3.64808	-4265.2	-553.4	88013008
	1989	3.10010	-4163.2	-1141.2	89072516
	1990	3.61994	-4137.8	-1288.2	90111424
	1991	3.40110	-4112.3	-1435.2	91122008
HIGH 24-Hour					
	1987	2.63780	-4403.8	-29.7	87111624
	1988	2.35662	-4248.2	-651.4	88013024
	1989	1.72367	-3255.7	2731.9	89040424
	1990	2.53735	-1746.9	2343.7	90101024
	1991	2.22535	-4265.2	-553.4	91102424
SOURCE GROUP ID:	POWAUG				
Annual					
	1987	0.12847	-4034.3	2343.7	87123124
	1988	0.12159	-4497.9	146.1	88123124
	1989	0.13597	-3984.6	2343.7	89123124
	1990	0.15794	-4084.0	2343.7	90123124
	1991	0.14759	-4183.5	2343.7	91123124
HIGH 1-Hour					
	1987	7.13789	1389.3	-1438.7	87073110
	1988	7.53174	-2940.3	2343.7	88100208
	1989	6.85262	-2492.8	2343.7	89110808
	1990	7.80494	-4680.7	2343.7	90071713
	1991	6.94937	2587.0	1334.9	91030916
HIGH 3-Hour					
	1987	4.68179	2110.4	1690.9	87062712
	1988	4.50880	490.8	2343.7	88060815
	1989	4.02276	-2343.6	2343.7	89060515
	1990	4.26754	-3993.3	-2120.9	90100812
	1991	4.89611	2428.2	1453.6	91060212
HIGH 8-Hour					
	1987	3.25740	2070.7	1720.6	87062716
	1988	3.11487	-4265.2	-553.4	88013008
	1989	2.64945	-4163.2	-1141.2	89072516
	1990	3.15206	-4146.2	-1239.2	90030816
	1991	3.08093	-5416.2	1860.3	91052124
HIGH 24-Hour					
	1987	2.27730	-4403.8	-29.7	87111624
	1988	2.02443	-4248.2	-651.4	88013024
	1989	1.36645	-3638.7	3053.2	89040424
	1990	2.11421	-1746.9	2343.7	90101024
	1991	2.01510	-5277.4	2343.7	91052124
SOURCE GROUP ID:	LD7535				
Annual					
	1987	0.19435	-3885.1	2343.7	87123124
	1988	0.17897	-4427.3	14.3	88123124
	1989	0.20711	-2244.1	2343.7	89123124
	1990	0.23603	-3934.8	2343.7	90123124
	1991	0.21732	-4034.3	2343.7	91123124
HIGH 1-Hour					
	1987	10.10817	-4568.6	278.0	87092716
	1988	8.82316	-3387.8	2343.7	88081609

	1989	10.14642	1314.5	2472.3	89080808
	1990	9.92997	2338.3	-1350.0	90072807
	1991	9.51054	-2343.6	2343.7	91071707
HIGH 3-Hour					
	1987	5.87058	2110.4	1690.9	87062712
	1988	6.38304	2070.7	1720.6	88110512
	1989	5.14556	-4545.0	234.0	89012515
	1990	5.73981	-3993.3	-2120.9	90100812
	1991	6.17214	2428.2	1453.6	91060212
HIGH 8-Hour					
	1987	4.62271	2070.7	1720.6	87062716
	1988	4.15796	-4265.2	-553.4	88013008
	1989	3.53755	-4163.2	-1141.2	89072516
	1990	4.22298	-4137.8	-1288.2	90111424
	1991	3.97887	-4265.2	-553.4	91102408
HIGH 24-Hour					
	1987	2.96488	-4380.2	-73.7	87111624
	1988	2.67051	-4248.2	-651.4	88013024
	1989	2.18397	-2691.7	2343.7	89040424
	1990	2.95858	-1746.9	2343.7	90101024
	1991	2.61716	-4273.7	-504.4	91102424
SOURCE GROUP ID:	LD7559				
Annual					
	1987	0.19719	-3885.1	2343.7	87123124
	1988	0.18139	-4427.3	14.3	88123124
	1989	0.21090	-2244.1	2343.7	89123124
	1990	0.23916	-3934.8	2343.7	90123124
	1991	0.22024	-4034.3	2343.7	91123124
HIGH 1-Hour					
	1987	10.11642	-4568.6	278.0	87092716
	1988	8.82371	-3387.8	2343.7	88081609
	1989	10.14406	1314.5	2472.3	89080808
	1990	9.93477	2338.3	-1350.0	90072807
	1991	9.51203	-2343.6	2343.7	91071707
HIGH 3-Hour					
	1987	5.90555	2110.4	1690.9	87062712
	1988	6.44326	2070.7	1720.6	88110512
	1989	5.19794	-4545.0	234.0	89012515
	1990	5.77943	-3993.3	-2120.9	90100812
	1991	6.19704	2428.2	1453.6	91060212
HIGH 8-Hour					
	1987	4.66696	2070.7	1720.6	87062716
	1988	4.19699	-4265.2	-553.4	88013008
	1989	3.56443	-4163.2	-1141.2	89072516
	1990	4.26624	-4137.8	-1288.2	90111424
	1991	4.02422	-4265.2	-553.4	91102408
HIGH 24-Hour					
	1987	2.98643	-4380.2	-73.7	87111624
	1988	2.69401	-4248.2	-651.4	88013024
	1989	2.22178	-2691.7	2343.7	89040424
	1990	2.98819	-1746.9	2343.7	90101024
	1991	2.64373	-4273.7	-504.4	91102424
SOURCE GROUP ID:	LD7595				
Annual					
	1987	0.21278	-3835.4	2343.7	87123124
	1988	0.19444	-4427.3	14.3	88123124
	1989	0.22579	-2293.9	2343.7	89123124
	1990	0.25697	-3885.1	2343.7	90123124
	1991	0.23594	-4034.3	2343.7	91123124
HIGH 1-Hour					
	1987	10.15497	-4568.6	278.0	87092716
	1988	9.25711	957.7	-2631.1	88111108
	1989	10.13137	1314.5	2472.3	89080808
	1990	9.97589	2338.3	-1350.0	90072807
	1991	9.69013	1974.9	-866.2	91021517
HIGH 3-Hour					
	1987	6.11127	2110.4	1690.9	87062712
	1988	6.79712	2070.7	1720.6	88110512
	1989	5.48310	-4545.0	234.0	89012515
	1990	6.02199	-3993.3	-2120.9	90100812
	1991	6.39737	2428.2	1453.6	91060212
HIGH 8-Hour					
	1987	4.92781	2070.7	1720.6	87062716
	1988	4.39250	-4265.2	-553.4	88013008

	1989	3.73087	-4163.2	-1141.2	89072516
	1990	4.49746	-4137.8	-1288.2	90111424
	1991	4.27560	-4265.2	-553.4	91102408
HIGH 24-Hour					
	1987	3.10599	-4380.2	-73.7	87111624
	1988	2.81324	-4248.2	-651.4	88013024
	1989	2.42573	-2691.7	2343.7	89040424
	1990	3.15547	-1746.9	2343.7	90101024
	1991	2.79263	-4273.7	-504.4	91102424
SOURCE GROUP ID:	LD5035				
Annual					
	1987	0.27813	-3735.9	2343.7	87123124
	1988	0.25102	-4403.8	-29.7	88123124
	1989	0.30263	-2393.3	2343.7	89123124
	1990	0.32872	-3735.9	2343.7	90123124
	1991	0.30153	-3934.8	2343.7	91123124
HIGH 1-Hour					
	1987	13.35206	-3686.2	2343.7	87092717
	1988	11.32395	1335.1	-872.0	88042712
	1989	17.40424	935.1	-903.1	89073010
	1990	11.78090	1335.1	-872.0	90073013
	1991	11.60522	1236.7	-872.9	91081712
HIGH 3-Hour					
	1987	7.37890	1991.3	1780.0	87062715
	1988	8.38270	1581.2	-869.7	88042712
	1989	6.99538	-4851.1	805.4	89091103
	1990	7.65066	2467.9	1423.9	90030318
	1991	7.44454	746.7	-1024.1	91081612
HIGH 8-Hour					
	1987	6.01688	2070.7	1720.6	87062716
	1988	5.15913	-4001.8	-2071.9	88011616
	1989	4.44163	-4163.2	-1141.2	89072516
	1990	5.37395	-4137.8	-1288.2	90111424
	1991	5.35971	-1299.3	2343.7	91021916
HIGH 24-Hour					
	1987	3.55804	-4380.2	-73.7	87111624
	1988	3.23867	-4248.2	-651.4	88013024
	1989	3.25799	-2691.7	2343.7	89040424
	1990	3.85264	-1746.9	2343.7	90101024
	1991	3.37845	-4273.7	-504.4	91102424
SOURCE GROUP ID:	LD5059				
Annual					
	1987	0.27986	-3735.9	2343.7	87123124
	1988	0.25237	-4403.8	-29.7	88123124
	1989	0.30438	-2393.3	2343.7	89123124
	1990	0.33055	-3735.9	2343.7	90123124
	1991	0.30325	-3934.8	2343.7	91123124
HIGH 1-Hour					
	1987	13.35960	-3686.2	2343.7	87092717
	1988	11.34772	1335.1	-872.0	88042712
	1989	17.40389	935.1	-903.1	89073010
	1990	11.79558	1335.1	-872.0	90073013
	1991	11.62819	1236.7	-872.9	91081712
HIGH 3-Hour					
	1987	7.39936	1991.3	1780.0	87062715
	1988	8.40178	1581.2	-869.7	88042712
	1989	7.05633	-4851.1	805.4	89091103
	1990	7.69621	2467.9	1423.9	90030318
	1991	7.43802	746.7	-1024.1	91081612
HIGH 8-Hour					
	1987	6.03179	2070.7	1720.6	87062716
	1988	5.18316	-4001.8	-2071.9	88011616
	1989	4.45058	-4163.2	-1141.2	89072516
	1990	5.39148	-4137.8	-1288.2	90111424
	1991	5.39056	-1299.3	2343.7	91021916
HIGH 24-Hour					
	1987	3.56536	-4380.2	-73.7	87111624
	1988	3.24849	-4248.2	-651.4	88013024
	1989	3.27682	-2691.7	2343.7	89040424
	1990	3.86664	-1746.9	2343.7	90101024
	1991	3.38831	-4273.7	-504.4	91102424
SOURCE GROUP ID:	LD5095				
Annual					
	1987	0.29167	-3686.2	2343.7	87123124

	1988	0.26281	-4403.8	-29.7	88123124
	1989	0.31886	-2443.0	2343.7	89123124
	1990	0.34382	-3735.9	2343.7	90123124
	1991	0.31537	-3885.1	2343.7	91123124
HIGH 1-Hour					
	1987	13.37686	-3686.2	2343.7	87092717
	1988	13.61898	-752.3	2343.7	88081413
	1989	17.43065	935.1	-903.1	89073010
	1990	13.13930	1165.8	-1865.7	90051107
	1991	12.05632	1236.7	-872.9	91081712
HIGH 3-Hour					
	1987	7.70064	2348.7	1512.9	87041821
	1988	8.66945	1581.2	-869.7	88042712
	1989	7.36160	-4851.1	805.4	89091103
	1990	8.04685	2467.9	1423.9	90030318
	1991	7.72642	746.7	-1024.1	91081612
HIGH 8-Hour					
	1987	6.21355	2070.7	1720.6	87062716
	1988	5.34666	-4001.8	-2071.9	88011616
	1989	4.56896	-4163.2	-1141.2	89072516
	1990	5.55823	-1846.3	2343.7	90021608
	1991	5.60866	-1299.3	2343.7	91021916
HIGH 24-Hour					
	1987	3.63665	-4380.2	-73.7	87111624
	1988	3.31666	-4248.2	-651.4	88013024
	1989	3.42532	-2641.9	2343.7	89040424
	1990	3.98780	-1746.9	2343.7	90101024
	1991	3.48411	-4273.7	-504.4	91102424

All receptor computations reported with respect to a user-specified origin

GRID	0.00	0.00
DISCRETE	0.00	0.00

COMBINED CYCLE
FUEL OIL
SUMMARY FILE

ISCBOB3R RELEASE 00285

ISCST3 OUTPUT FILE NUMBER 1 :comboil.087
ISCST3 OUTPUT FILE NUMBER 2 :comboil.088
ISCST3 OUTPUT FILE NUMBER 3 :comboil.089
ISCST3 OUTPUT FILE NUMBER 4 :comboil.090
ISCST3 OUTPUT FILE NUMBER 5 :comboil.091
First title for last output file is: FPL MARTIN PROPOSED COMBINED CYCLE CTS 12/20/01
Second title for last output file is: SIGNIFICANT IMPACT ANALYSIS, SITE VICINITY, GENERIC 10G/S, F

AVERAGING TIME	YEAR	CONC (ug/m3)	X (m)	Y (m)	PERIOD ENDING (YYMMDDHH)
SOURCE GROUP ID: BSDB35					
Annual					
	1987	0.05345	-7794.2	4500.0	87123124
	1988	0.05165	-7495.4	261.8	88123124
	1989	0.06021	-3847.5	4273.1	89123124
	1990	0.06531	-7361.2	4250.0	90123124
	1991	0.06245	-7063.6	3755.8	91123124
HIGH 1-Hour					
	1987	4.37267	2547.3	1364.5	87072409
	1988	3.85409	-4205.7	-896.3	88073108
	1989	4.05146	2509.2	2786.8	89080909
	1990	5.21396	746.7	-1024.1	90081212
	1991	3.86139	-1539.1	4228.6	91073108
HIGH 3-Hour					
	1987	2.42739	2110.4	1690.9	87062712
	1988	2.40806	623.7	2934.4	88060815
	1989	2.45592	-2691.7	2343.7	89071515
	1990	2.28858	-2691.7	2343.7	90052815
	1991	2.52244	-2840.9	2343.7	91070615
HIGH 8-Hour					
	1987	1.44973	-4546.6	-2625.0	87110116
	1988	1.39883	-4273.7	-504.4	88061816
	1989	1.54198	-2343.6	2343.7	89060516
	1990	1.38194	-5286.9	-1516.0	90030816
	1991	1.73352	-5439.8	1904.2	91052124
HIGH 24-Hour					
	1987	0.95648	-6000.0	0.0	87111624
	1988	0.84407	-5941.6	-835.0	88013024
	1989	0.59259	-6691.3	7431.5	89031524
	1990	0.90512	-2645.0	3640.6	90101024
	1991	1.11907	-5526.1	2343.7	91052124
SOURCE GROUP ID: BSDB59					
Annual					
	1987	0.05758	-7361.2	4250.0	87123124
	1988	0.05448	-6995.7	244.3	88123124
	1989	0.06403	-3680.2	4087.3	89123124
	1990	0.07011	-6928.2	4000.0	90123124
	1991	0.06674	-6622.1	3521.0	91123124
HIGH 1-Hour					
	1987	4.58986	-4615.7	365.9	87091110
	1988	3.81798	-4028.2	2517.1	88080108
	1989	4.82894	2825.3	1156.8	89073012
	1990	5.24568	746.7	-1024.1	90081212
	1991	3.87253	-4010.3	-2023.0	91102109
HIGH 3-Hour					
	1987	2.59036	2110.4	1690.9	87062712
	1988	2.53362	602.9	2836.6	88060815
	1989	2.57628	-2691.7	2343.7	89071515
	1990	2.42262	-2691.7	2343.7	90052815
	1991	2.64398	-2840.9	2343.7	91070615
HIGH 8-Hour					
	1987	1.58029	-3976.4	-2218.9	87110116
	1988	1.45231	-4282.1	-455.5	88061816
	1989	1.61462	-2343.6	2343.7	89060516
	1990	1.50128	-5046.6	-1447.1	90030816
	1991	1.85606	-5439.8	1904.2	91052124
HIGH 24-Hour					
	1987	1.03895	-5500.0	0.0	87111624
	1988	0.91792	-5694.0	-800.3	88013024
	1989	0.62955	-6946.6	7193.4	89031524

	1990	0.96497	-2498.1	3438.3	90101024
	1991	1.19833	-5476.3	2343.7	91052124
SOURCE GROUP ID:	BSDB95				
Annual					
	1987	0.06545	-6495.2	3750.0	87123124
	1988	0.06203	-6496.0	226.9	88123124
	1989	0.07269	-3345.6	3715.7	89123124
	1990	0.07948	-6495.2	3750.0	90123124
	1991	0.07600	-5959.9	3168.9	91123124
HIGH 1-Hour					
	1987	4.59656	-4615.7	365.9	87091110
	1988	4.83026	4851.5	1209.6	88112314
	1989	5.00736	899.1	-2225.2	89052509
	1990	5.30922	746.7	-1024.1	90081212
	1991	4.36367	2155.1	1940.5	91092610
HIGH 3-Hour					
	1987	2.88921	2110.4	1690.9	87062712
	1988	2.76357	582.2	2738.8	88060815
	1989	2.78195	-2691.7	2343.7	89071515
	1990	2.68565	-4497.9	146.1	90070712
	1991	2.84913	-2840.9	2343.7	91070615
HIGH 8-Hour					
	1987	1.81760	-3976.4	-2218.9	87110116
	1988	1.63722	-5446.5	-765.5	88013008
	1989	1.75377	-2343.6	2343.7	89060516
	1990	1.73453	-4566.0	-1309.3	90030816
	1991	2.06766	-5439.8	1904.2	91052124
HIGH 24-Hour					
	1987	1.19888	-5000.0	0.0	87111624
	1988	1.06253	-5198.9	-730.7	88013024
	1989	0.69574	-6946.6	7193.4	89031524
	1990	1.09381	-2351.1	3236.1	90101024
	1991	1.33626	-5426.6	2343.7	91052124
SOURCE GROUP ID:	LD7535				
Annual					
	1987	0.09041	-5196.1	3000.0	87123124
	1988	0.08560	-5246.8	183.2	88123124
	1989	0.09825	-2676.5	2972.6	89123124
	1990	0.11049	-4979.6	2875.0	90123124
	1991	0.10454	-4332.6	2343.7	91123124
HIGH 1-Hour					
	1987	6.01092	1989.7	-1342.1	87092110
	1988	5.58265	90.7	2598.4	88052809
	1989	5.78652	3425.8	1525.3	89051107
	1990	5.51579	746.7	-1024.1	90081212
	1991	5.51047	2587.0	1334.9	91030916
HIGH 3-Hour					
	1987	3.71006	2110.4	1690.9	87062712
	1988	3.45186	519.8	2445.4	88060815
	1989	3.30689	-2691.7	2343.7	89071515
	1990	3.23950	-2691.7	2343.7	90052815
	1991	3.60914	-4222.7	-798.3	91040406
HIGH 8-Hour					
	1987	2.42409	-3976.4	-2218.9	87110116
	1988	2.32795	-4265.2	-553.4	88013008
	1989	2.10758	-2343.6	2343.7	89060516
	1990	2.42864	-4146.2	-1239.2	90030816
	1991	2.57478	-5439.8	1904.2	91052124
HIGH 24-Hour					
	1987	1.70454	-4403.8	-29.7	87111624
	1988	1.52604	-4248.2	-651.4	88013024
	1989	0.95329	-4596.3	3856.7	89040424
	1990	1.51041	-1746.9	2343.7	90101024
	1991	1.67339	-5327.2	2343.7	91052124
SOURCE GROUP ID:	LD7559				
Annual					
	1987	0.09310	-5196.1	3000.0	87123124
	1988	0.08783	-4997.0	174.5	88123124
	1989	0.10105	-2676.5	2972.6	89123124
	1990	0.11374	-4979.6	2875.0	90123124
	1991	0.10776	-4332.6	2343.7	91123124
HIGH 1-Hour					
	1987	6.01104	1989.7	-1342.1	87092110
	1988	5.58365	90.7	2598.4	88052809

	1989	5.78754	3425.8	1525.3	89051107
	1990	5.53109	746.7	-1024.1	90081212
	1991	5.61765	2587.0	1334.9	91030916
HIGH 3-Hour					
	1987	3.78205	2110.4	1690.9	87062712
	1988	3.50631	519.8	2445.4	88060815
	1989	3.34313	-2691.7	2343.7	89071515
	1990	3.28251	-2691.7	2343.7	90052815
	1991	3.68178	-4222.7	-798.3	91040406
HIGH 8-Hour					
	1987	2.47555	-3976.4	-2218.9	87110116
	1988	2.39962	-4265.2	-553.4	88013008
	1989	2.13852	-2343.6	2343.7	89060516
	1990	2.48977	-4146.2	-1239.2	90030816
	1991	2.61516	-5416.2	1860.3	91052124
HIGH 24-Hour					
	1987	1.75051	-4403.8	-29.7	87111624
	1988	1.57074	-4248.2	-651.4	88013024
	1989	0.98243	-4596.3	3856.7	89040424
	1990	1.55468	-1746.9	2343.7	90101024
	1991	1.70066	-5327.2	2343.7	91052124
SOURCE GROUP ID:	LD7595				
Annual					
	1987	0.09830	-4979.6	2875.0	87123124
	1988	0.09213	-4997.0	174.5	88123124
	1989	0.10694	-2509.2	2786.8	89123124
	1990	0.11996	-4763.1	2750.0	90123124
	1991	0.11383	-4282.9	2343.7	91123124
HIGH 1-Hour					
	1987	6.01284	1989.7	-1342.1	87092110
	1988	5.59125	-155.6	2343.7	88052309
	1989	5.79164	3425.8	1525.3	89051107
	1990	5.78904	1957.2	-2901.6	90042308
	1991	5.80732	2189.9	1631.6	91021415
HIGH 3-Hour					
	1987	3.91215	2110.4	1690.9	87062712
	1988	3.60066	490.8	2343.7	88060815
	1989	3.40468	-2691.7	2343.7	89071515
	1990	3.36387	-4027.3	-1925.0	90022624
	1991	3.81255	-4222.7	-798.3	91040406
HIGH 8-Hour					
	1987	2.56798	-3976.4	-2218.9	87110116
	1988	2.53158	-4265.2	-553.4	88013008
	1989	2.21227	-2343.6	2343.7	89060516
	1990	2.60042	-4146.2	-1239.2	90030816
	1991	2.68737	-5416.2	1860.3	91052124
HIGH 24-Hour					
	1987	1.83368	-4403.8	-29.7	87111624
	1988	1.65276	-4248.2	-651.4	88013024
	1989	1.03771	-4404.8	3696.0	89040424
	1990	1.63620	-1746.9	2343.7	90101024
	1991	1.74896	-5327.2	2343.7	91052124
SOURCE GROUP ID:	LD5035				
Annual					
	1987	0.14050	-3984.6	2343.7	87123124
	1988	0.12982	-4497.9	146.1	88123124
	1989	0.14894	-2144.7	2343.7	89123124
	1990	0.17021	-4034.3	2343.7	90123124
	1991	0.15927	-4183.5	2343.7	91123124
HIGH 1-Hour					
	1987	7.12469	1389.3	-1438.7	87073110
	1988	7.52947	-2940.3	2343.7	88100208
	1989	7.03941	744.6	-877.3	89092113
	1990	7.84729	-4680.7	2343.7	90071713
	1991	7.27463	2220.9	-863.9	91021514
HIGH 3-Hour					
	1987	4.82196	2110.4	1690.9	87062712
	1988	4.62181	2070.7	1720.6	88110512
	1989	4.12600	-2343.6	2343.7	89060515
	1990	4.41013	-3993.3	-2120.9	90100812
	1991	4.82224	2428.2	1453.6	91060212
HIGH 8-Hour					
	1987	3.42146	2070.7	1720.6	87062716
	1988	3.35803	-4265.2	-553.4	88013008

	1989	2.72800	-4163.2	-1141.2	89072516
	1990	3.30599	-4146.2	-1239.2	90030816
	1991	3.16208	-4112.3	-1435.2	91122008
HIGH 24-Hour					
	1987	2.38296	-4403.8	-29.7	87111624
	1988	2.16813	-4248.2	-651.4	88013024
	1989	1.48290	-3447.2	2892.5	89040424
	1990	2.22879	-1746.9	2343.7	90101024
	1991	2.05994	-5277.4	2343.7	91052124
SOURCE GROUP ID:	LD5059				
Annual					
	1987	0.14112	-3984.6	2343.7	87123124
	1988	0.13032	-4497.9	146.1	88123124
	1989	0.14947	-2144.7	2343.7	89123124
	1990	0.17080	-4034.3	2343.7	90123124
	1991	0.15996	-4183.5	2343.7	91123124
HIGH 1-Hour					
	1987	7.12408	2110.4	1690.9	87012212
	1988	7.52936	-2940.3	2343.7	88100208
	1989	7.05141	744.6	-877.3	89092113
	1990	7.84949	-4680.7	2343.7	90071713
	1991	7.29542	2220.9	-863.9	91021514
HIGH 3-Hour					
	1987	4.82860	2110.4	1690.9	87062712
	1988	4.63354	2070.7	1720.6	88110512
	1989	4.13092	-2343.6	2343.7	89060515
	1990	4.41679	-3993.3	-2120.9	90100812
	1991	4.82703	2428.2	1453.6	91060212
HIGH 8-Hour					
	1987	3.42943	2070.7	1720.6	87062716
	1988	3.36991	-4265.2	-553.4	88013008
	1989	2.73239	-4163.2	-1141.2	89072516
	1990	3.31333	-4146.2	-1239.2	90030816
	1991	3.17139	-4112.3	-1435.2	91122008
HIGH 24-Hour					
	1987	2.38800	-4403.8	-29.7	87111624
	1988	2.17512	-4248.2	-651.4	88013024
	1989	1.48910	-3447.2	2892.5	89040424
	1990	2.23490	-1746.9	2343.7	90101024
	1991	2.06201	-5277.4	2343.7	91052124
SOURCE GROUP ID:	LD5095				
Annual					
	1987	0.14158	-3984.6	2343.7	87123124
	1988	0.13059	-4497.9	146.1	88123124
	1989	0.14906	-2144.7	2343.7	89123124
	1990	0.17118	-4034.3	2343.7	90123124
	1991	0.16005	-4183.5	2343.7	91123124
HIGH 1-Hour					
	1987	7.11985	1389.3	-1438.7	87073110
	1988	7.52847	-2940.3	2343.7	88100208
	1989	7.03989	744.6	-877.3	89092113
	1990	7.85314	-4680.7	2343.7	90071713
	1991	7.30323	2220.9	-863.9	91021514
HIGH 3-Hour					
	1987	4.82296	2110.4	1690.9	87062712
	1988	4.62592	2070.7	1720.6	88110512
	1989	4.12493	-2343.6	2343.7	89060515
	1990	4.40612	-3993.3	-2120.9	90100812
	1991	4.81284	2428.2	1453.6	91060212
HIGH 8-Hour					
	1987	3.42523	2070.7	1720.6	87062716
	1988	3.37797	-4265.2	-553.4	88013008
	1989	2.72767	-4163.2	-1141.2	89072516
	1990	3.31437	-4146.2	-1239.2	90030816
	1991	3.17726	-4112.3	-1435.2	91122008
HIGH 24-Hour					
	1987	2.38715	-4403.8	-29.7	87111624
	1988	2.17928	-4248.2	-651.4	88013024
	1989	1.49101	-3447.2	2892.5	89040424
	1990	2.23484	-1746.9	2343.7	90101024
	1991	2.06013	-5277.4	2343.7	91052124

All receptor computations reported with respect to a user-specified origin

GRID	0.00	0.00
DISCRETE	0.00	0.00

PM_{10} REFINED ANALYSIS
ISCST3 SUMMARY

ISCBOB3R RELEASE 00285

ISCST3 OUTPUT FILE NUMBER 1 :coolpm.087
ISCST3 OUTPUT FILE NUMBER 2 :coolpm.088
ISCST3 OUTPUT FILE NUMBER 3 :coolpm.089
ISCST3 OUTPUT FILE NUMBER 4 :coolpm.090
ISCST3 OUTPUT FILE NUMBER 5 :coolpm.091
First title for last output file is: FPL MARTIN PROPOSED COMBINED CYCLE CTS 12/20/01
Second title for last output file is: SIGNIFICANT IMPACT ANALYSIS, SITE VICINITY, GENERIC 10G/S, FU

AVERAGING TIME	YEAR	CONC (ug/m3)	X (m)	Y (m)	PERIOD ENDING (YYMMDDHH)
SOURCE GROUP ID:	ALL				
Annual					
	1987	0.28224	-3934.8	2343.7	87123124
	1988	0.26072	-4427.3	14.3	88123124
	1989	0.31370	-2194.4	2343.7	89123124
	1990	0.33932	-3984.6	2343.7	90123124
	1991	0.31566	-4183.5	2343.7	91123124
HIGH 24-Hour					
	1987	4.36750	-4380.2	-73.7	87111624
	1988	3.96095	-4248.2	-651.4	88013024
	1989	2.89090	-3064.2	2571.1	89040424
	1990	4.31530	-1796.6	2343.7	90101024
	1991	3.69525	-5277.4	2343.7	91052124
SOURCE GROUP ID:	LD5035				
Annual					
	1987	0.23667	-3984.6	2343.7	87123124
	1988	0.21868	-4497.9	146.1	88123124
	1989	0.25087	-2144.7	2343.7	89123124
	1990	0.28670	-4034.3	2343.7	90123124
	1991	0.26829	-4183.5	2343.7	91123124
HIGH 24-Hour					
	1987	4.01396	-4403.8	-29.7	87111624
	1988	3.65210	-4248.2	-651.4	88013024
	1989	2.49786	-3447.2	2892.5	89040424
	1990	3.75427	-1746.9	2343.7	90101024
	1991	3.46985	-5277.4	2343.7	91052124
SOURCE GROUP ID:	COOL				
Annual					
	1987	0.04937	-2940.3	2343.7	87123124
	1988	0.04776	-2741.4	2343.7	88123124
	1989	0.06533	-2393.3	2343.7	89123124
	1990	0.05799	-2592.2	2343.7	90123124
	1991	0.05653	-2045.2	2343.7	91123124
HIGH 24-Hour					
	1987	0.83634	749.5	-1219.9	87101324
	1988	0.71289	43.3	2343.7	88090524
	1989	0.63831	-1597.7	2343.7	89060924
	1990	0.70676	748.8	-1170.9	90072724
	1991	0.65222	-901.5	2343.7	91030224

All receptor computations reported with respect to a user-specified origin

GRID	0.00	0.00
DISCRETE	0.00	0.00

SO_2 AAQS ANALYSIS
ISCST3 SUMMARY

ISCBOB3R RELEASE 00285

ISCST3 OUTPUT FILE NUMBER 1 :comboil.087
ISCST3 OUTPUT FILE NUMBER 2 :comboil.088
ISCST3 OUTPUT FILE NUMBER 3 :comboil.089
ISCST3 OUTPUT FILE NUMBER 4 :comboil.090
ISCST3 OUTPUT FILE NUMBER 5 :comboil.091
First title for last output file is: FPL MARTIN PROPOSED COMBINED CYCLE CTS 12/20/01
Second title for last output file is: SIGNIFICANT IMPACT ANALYSIS, SITE VICINITY, GENERIC 10G/S, FU

AVERAGING TIME	YEAR	CONC (ug/m3)	X (m)	Y (m)	PERIOD ENDING (YYMMDDHH)
SOURCE GROUP ID:	LD5035				
HSH 24-Hour					
	1987	6.31906	-4521.5	190.1	87123124
	1988	5.47545	-4180.2	-1043.3	88013024
	1989	4.66681	-2542.5	2343.7	89060424
	1990	6.81151	-4163.2	-1141.2	90030824
	1991	6.30369	-4265.2	-553.4	91040424
SOURCE GROUP ID:	ALL				
HSH 24-Hour					
	1987	72.97417	-4145.2	2796.0	87061924
	1988	72.18076	-3785.6	2343.7	88071124
	1989	62.52339	-4282.9	2343.7	89073124
	1990	69.05883	-4233.2	2343.7	90050424
	1991	74.02855	-3715.7	3345.6	91072424

All receptor computations reported with respect to a user-specified origin

GRID	0.00	0.00
DISCRETE	0.00	0.00

SO_2 PSD CLASS II ANALYSIS
ISCST3 SUMMARY

ISCBOB3R RELEASE 00285

ISCST3 OUTPUT FILE NUMBER 1 :psdoil.087
ISCST3 OUTPUT FILE NUMBER 2 :psdoil.088
ISCST3 OUTPUT FILE NUMBER 3 :psdoil.089
ISCST3 OUTPUT FILE NUMBER 4 :psdoil.090
ISCST3 OUTPUT FILE NUMBER 5 :psdoil.091
First title for last output file is: FPL MARTIN PROPOSED COMBINED CYCLE CTS 12/20/01
Second title for last output file is: SIGNIFICANT IMPACT ANALYSIS, SITE VICINITY, GENERIC 10G/S, FU

AVERAGING TIME	YEAR	CONC (ug/m3)	X (m)	Y (m)	PERIOD ENDING (YYMMDDHH)
SOURCE GROUP ID:	LD5035				
HSH 24-Hour					
	1987	6.31906	-4521.5	190.1	87123124
	1988	5.47545	-4180.2	-1043.3	88013024
	1989	4.66681	-2542.5	2343.7	89060424
	1990	6.81151	-4163.2	-1141.2	90030824
	1991	6.30369	-4265.2	-553.4	91040424
SOURCE GROUP ID:	ALL				
HSH 24-Hour					
	1987	41.39065	-2741.4	2343.7	87080724
	1988	36.22301	-3830.2	3213.9	88090924
	1989	37.41634	-1995.5	2343.7	89061524
	1990	38.79645	-4061.3	-1729.1	90100924
	1991	37.97731	-4233.2	2343.7	91052124

All receptor computations reported with respect to a user-specified origin

GRID	0.00	0.00
DISCRETE	0.00	0.00

EXAMPLE ISCST3
INPUT FILE

```
**
***************************************
**
** ISCST3 Input Produced by:
** ISC-AERMOD View Ver. 4.03
** Lakes Environmental Software Inc.
** Date: 12/20/01
** File: D:\martin\martin1.INP
**
***************************************
**
**
***************************************
** ISCST3 Control Pathway
***************************************
**
**
CO STARTING
   TITLEONE FPL MARTIN PROPOSED COMBINED CYCLE CTS          12/20/01
   TITLETWO SIGNIFICANT IMPACT ANALYSIS, SITE VICINITY, GENERIC 10G/S, Nat. Gas
   MODELOPT DFAULT CONC NOCMPL  RURAL
   AVERTIME 1 3 8 24 PERIOD
   POLLUTID GEN
   TERRHGTS FLAT
   RUNORNOT RUN
CO FINISHED
**
***************************************
** ISCST3 Source Pathway
***************************************
**
**
SO STARTING
** Source Location **
** Source ID - Type - X Coord. - Y Coord. **
   LOCATION BSDB35A POINT -152.72 55.009
   LOCATION BSDB35B POINT -107.14 55.009
   LOCATION BSDB35C POINT 0.00000 55.009
   LOCATION BSDB35D POINT 45.7200 55.009

   LOCATION BSDB59A POINT -152.72 55.009
   LOCATION BSDB59B POINT -107.14 55.009
   LOCATION BSDB59C POINT 0.00000 55.009
   LOCATION BSDB59D POINT 45.7200 55.009

   LOCATION BSDB95A POINT -152.72 55.009
   LOCATION BSDB95B POINT -107.14 55.009
   LOCATION BSDB95C POINT 0.00000 55.009
   LOCATION BSDB95D POINT 45.7200 55.009

   LOCATION POWAUGA POINT -152.72 55.009
   LOCATION POWAUGB POINT -107.14 55.009
   LOCATION POWAUGC POINT 0.00000 55.009
   LOCATION POWAUGD POINT 45.7200 55.009

   LOCATION LD7535A POINT -152.72 55.009
   LOCATION LD7535B POINT -107.14 55.009
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LOCATION LD7535C POINT 0.00000 55.009
LOCATION LD7535D POINT 45.7200 55.009

LOCATION LD7559A POINT -152.72 55.009
LOCATION LD7559B POINT -107.14 55.009
LOCATION LD7559C POINT 0.00000 55.009
LOCATION LD7559D POINT 45.7200 55.009

LOCATION LD7595A POINT -152.72 55.009
LOCATION LD7595B POINT -107.14 55.009
LOCATION LD7595C POINT 0.00000 55.009
LOCATION LD7595D POINT 45.7200 55.009

LOCATION LD5035A POINT -152.72 55.009
LOCATION LD5035B POINT -107.14 55.009
LOCATION LD5035C POINT 0.00000 55.009
LOCATION LD5035D POINT 45.7200 55.009

LOCATION LD5059A POINT -152.72 55.009
LOCATION LD5059B POINT -107.14 55.009
LOCATION LD5059C POINT 0.00000 55.009
LOCATION LD5059D POINT 45.7200 55.009

LOCATION LD5095A POINT -152.72 55.009
LOCATION LD5095B POINT -107.14 55.009
LOCATION LD5095C POINT 0.00000 55.009
LOCATION LD5095D POINT 45.7200 55.009

** Source Parameters **
SRCPARAM BSDB35A 2.25 36.576 360 18.6 5.7912
SRCPARAM BSDB35B 2.25 36.576 360 18.6 5.7912
SRCPARAM BSDB35C 2.25 36.576 360 18.6 5.7912
SRCPARAM BSDB35D 2.25 36.576 360 18.6 5.7912

SRCPARAM BSDB59A 2.25 36.576 360 17.8 5.7912
SRCPARAM BSDB59B 2.25 36.576 360 17.8 5.7912
SRCPARAM BSDB59C 2.25 36.576 360 17.8 5.7912
SRCPARAM BSDB59D 2.25 36.576 360 17.8 5.7912

SRCPARAM BSDB95A 2.25 36.576 361 16.5 5.7912
SRCPARAM BSDB95B 2.25 36.576 361 16.5 5.7912
SRCPARAM BSDB95C 2.25 36.576 361 16.5 5.7912
SRCPARAM BSDB95D 2.25 36.576 361 16.5 5.7912

SRCPARAM POWAUGA 2.25 36.576 369 17.6 5.7912
SRCPARAM POWAUGB 2.25 36.576 369 17.6 5.7912
SRCPARAM POWAUGC 2.25 36.576 369 17.6 5.7912
SRCPARAM POWAUGD 2.25 36.576 369 17.6 5.7912

SRCPARAM LD7535A 2.25 36.576 359 14.7 5.7912
SRCPARAM LD7535B 2.25 36.576 359 14.7 5.7912
SRCPARAM LD7535C 2.25 36.576 359 14.7 5.7912
SRCPARAM LD7535D 2.25 36.576 359 14.7 5.7912

SRCPARAM LD7559A 2.25 36.576 360 14.4 5.7912
SRCPARAM LD7559B 2.25 36.576 360 14.4 5.7912
SRCPARAM LD7559C 2.25 36.576 360 14.4 5.7912
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SRCPARAM LD7559D 2.25 36.576 360 14.4 5.7912

SRCPARAM LD7595A 2.25 36.576 361 13.5 5.7912
SRCPARAM LD7595B 2.25 36.576 361 13.5 5.7912
SRCPARAM LD7595C 2.25 36.576 361 13.5 5.7912
SRCPARAM LD7595D 2.25 36.576 361 13.5 5.7912

SRCPARAM LD5035A 2.25 36.576 353 11.9 5.7912
SRCPARAM LD5035B 2.25 36.576 353 11.9 5.7912
SRCPARAM LD5035C 2.25 36.576 353 11.9 5.7912
SRCPARAM LD5035D 2.25 36.576 353 11.9 5.7912

SRCPARAM LD5059A 2.25 36.576 354 11.7 5.7912
SRCPARAM LD5059B 2.25 36.576 354 11.7 5.7912
SRCPARAM LD5059C 2.25 36.576 354 11.7 5.7912
SRCPARAM LD5059D 2.25 36.576 354 11.7 5.7912

SRCPARAM LD5095A 2.25 36.576 353 11.4 5.7912
SRCPARAM LD5095B 2.25 36.576 353 11.4 5.7912
SRCPARAM LD5095C 2.25 36.576 353 11.4 5.7912
SRCPARAM LD5095D 2.25 36.576 353 11.4 5.7912

** Building Downwash **
BUILDHGT BSDB35A-BSDB95A 25.30 25.30 25.30 25.30 25.30 25.30
BUILDHGT BSDB35A-BSDB95A 25.30 25.30 25.30 25.30 25.30 25.30
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BUILDWID BSDB35A-BSDB95A 13.25 16.64 19.53 21.83 23.46 24.38
BUILDWID BSDB35A-BSDB95A 24.56 24.00 22.70 24.00 24.57 24.39
BUILDWID BSDB35A-BSDB95A 23.47 21.83 19.53 16.64 13.25 9.45
BUILDWID BSDB35A-BSDB95A 13.25 16.64 19.53 21.83 23.46 24.38
BUILDWID BSDB35A-BSDB95A 24.56 24.00 22.70 24.00 24.57 24.39
BUILDWID BSDB35A-BSDB95A 23.47 21.83 19.53 16.64 13.25 9.45
BUILDWID BSDB35B-BSDB95B 13.25 16.64 19.53 21.83 23.46 24.38
BUILDWID BSDB35B-BSDB95B 24.56 24.00 22.70 24.00 24.57 24.39
BUILDWID BSDB35B-BSDB95B 23.47 21.83 19.54 16.64 13.25 9.45
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BUILDWID BSDB35B-BSDB95B 13.25 16.64 19.53 21.83 23.46 24.38
BUILDWID BSDB35B-BSDB95B 24.56 24.00 22.70 24.00 24.57 24.39
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BUILDWID BSDB35C-BSDB95C 13.25 16.65 19.54 21.83 23.46 24.38
BUILDWID BSDB35C-BSDB95C 24.56 24.00 22.70 24.00 24.56 24.38
BUILDWID BSDB35C-BSDB95C 23.46 21.83 19.53 16.64 13.25 9.45
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BUILDWID BSDB35C-BSDB95C 23.46 21.83 19.53 16.64 13.25 9.45
BUILDWID BSDB35D-BSDB95D 13.25 16.65 19.54 21.83 23.46 24.38
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BUILDWID BSDB35D-BSDB95D 24.56 24.00 22.70 24.00 24.56 24.38
BUILDWID BSDB35D-BSDB95D 23.46 21.83 19.53 16.64 13.25 9.45


BUILDHGT POWAUGA 25.30 25.30 25.30 25.30 25.30 25.30
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BUILDWID POWAUGA 24.56 24.00 22.70 24.00 24.57 24.39
BUILDWID POWAUGA 23.47 21.83 19.53 16.64 13.25 9.45
BUILDWID POWAUGA 13.25 16.64 19.53 21.83 23.46 24.38
BUILDWID POWAUGA 24.56 24.00 22.70 24.00 24.57 24.39
BUILDWID POWAUGA 23.47 21.83 19.53 16.64 13.25 9.45
BUILDWID POWAUGB 13.25 16.64 19.53 21.83 23.46 24.38
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BUILDWID POWAUGB 23.47 21.83 19.54 16.64 13.25 9.45
BUILDWID POWAUGB 13.25 16.64 19.53 21.83 23.46 24.38
BUILDWID POWAUGB 24.56 24.00 22.70 24.00 24.57 24.39
BUILDWID POWAUGB 23.47 21.83 19.54 16.64 13.25 9.45
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BUILDWID POWAUGC 24.56 24.00 22.70 24.00 24.56 24.38
BUILDWID POWAUGC 23.46 21.83 19.53 16.64 13.25 9.45
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BUILDWID POWAUGC 13.25 16.65 19.54 21.83 23.46 24.38
BUILDWID POWAUGC 24.56 24.00 22.70 24.00 24.56 24.38
BUILDWID POWAUGC 23.46 21.83 19.53 16.64 13.25 9.45
BUILDWID POWAUGD 13.25 16.65 19.54 21.83 23.46 24.38
BUILDWID POWAUGD 24.56 24.00 22.70 24.00 24.56 24.38
BUILDWID POWAUGD 23.46 21.83 19.53 16.64 13.25 9.45
BUILDWID POWAUGD 13.25 16.65 19.54 21.83 23.46 24.38
BUILDWID POWAUGD 24.56 24.00 22.70 24.00 24.56 24.38
BUILDWID POWAUGD 23.46 21.83 19.53 16.64 13.25 9.45

BUILDHGT LD7535A-LD7595A 25.30 25.30 25.30 25.30 25.30 25.30
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BUILDWID LD7535A-LD7595A 23.47 21.83 19.53 16.64 13.25 9.45
BUILDWID LD7535A-LD7595A 13.25 16.64 19.53 21.83 23.46 24.38
BUILDWID LD7535A-LD7595A 24.56 24.00 22.70 24.00 24.57 24.39
BUILDWID LD7535A-LD7595A 23.47 21.83 19.53 16.64 13.25 9.45
BUILDWID LD7535B-LD7595B 13.25 16.64 19.53 21.83 23.46 24.38
BUILDWID LD7535B-LD7595B 24.56 24.00 22.70 24.00 24.57 24.39
BUILDWID LD7535B-LD7595B 23.47 21.83 19.54 16.64 13.25 9.45
BUILDWID LD7535B-LD7595B 13.25 16.64 19.53 21.83 23.46 24.38
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BUILDWID LD7535B-LD7595B 23.47 21.83 19.54 16.64 13.25 9.45
BUILDWID LD7535C-LD7595C 13.25 16.65 19.54 21.83 23.46 24.38
BUILDWID LD7535C-LD7595C 24.56 24.00 22.70 24.00 24.56 24.38
BUILDWID LD7535C-LD7595C 23.46 21.83 19.53 16.64 13.25 9.45
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BUILDWID LD7535D-LD7595D 24.56 24.00 22.70 24.00 24.56 24.38
BUILDWID LD7535D-LD7595D 23.46 21.83 19.53 16.64 13.25 9.45
BUILDWID LD7535D-LD7595D 13.25 16.65 19.54 21.83 23.46 24.38
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BUILDWID LD7535D-LD7595D 24.56 24.00 22.70 24.00 24.56 24.38
BUILDWID LD7535D-LD7595D 23.46 21.83 19.53 16.64 13.25 9.45

BUILDHGT LD5035A-LD5095A 25.30 25.30 25.30 25.30 25.30 25.30
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BUILDWID LD5035A-LD5095A 13.25 16.64 19.53 21.83 23.46 24.38
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BUILDWID LD5035A-LD5095A 23.47 21.83 19.53 16.64 13.25 9.45
BUILDWID LD5035A-LD5095A 13.25 16.64 19.53 21.83 23.46 24.38
BUILDWID LD5035A-LD5095A 24.56 24.00 22.70 24.00 24.57 24.39
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BUILDWID LD5035B-LD5095B 23.47 21.83 19.54 16.64 13.25 9.45
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BUILDWID LD5035D-LD5095D 13.25 16.65 19.54 21.83 23.46 24.38
BUILDWID LD5035D-LD5095D 24.56 24.00 22.70 24.00 24.56 24.38
BUILDWID LD5035D-LD5095D 23.46 21.83 19.53 16.64 13.25 9.45

CONCUNIT 1000000 (GRAMS/SEC) (MICROGRAMS/CUBIC-METER)

SRCGROUP BSDB35   BSDB35A BSDB35B BSDB35C BSDB35D
SRCGROUP BSDB59   BSDB59A BSDB59B BSDB59C BSDB59D
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   SRCGROUP LD7535  LD7535A LD7535B LD7535C LD7535D
   SRCGROUP LD7559  LD7559A LD7559B LD7559C LD7559D
   SRCGROUP LD7595  LD7595A LD7595B LD7595C LD7595D
   SRCGROUP LD5035  LD5035A LD5035B LD5035C LD5035D
   SRCGROUP LD5059  LD5059A LD5059B LD5059C LD5059D
   SRCGROUP LD5095  LD5095A LD5095B LD5095C LD5095D


SO FINISHED
**
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** ISCST3 Receptor Pathway
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**
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RE STARTING
   DISCCART 0.00 2400.00
   DISCCART 0.00 2500.00
   DISCCART 0.00 2600.00
   DISCCART 0.00 2700.00
   DISCCART 0.00 2800.00
   DISCCART 0.00 2900.00
   DISCCART 83.76 2398.54
   DISCCART 87.25 2498.48
   DISCCART 90.74 2598.42
   DISCCART 94.23 2698.36
   DISCCART 97.72 2798.29
   DISCCART 101.21 2898.23
   DISCCART 167.42 2394.15
   DISCCART 174.39 2493.91
   DISCCART 181.37 2593.67
   DISCCART 188.34 2693.42
   DISCCART 195.32 2793.18
   DISCCART 202.29 2892.94
   DISCCART 250.87 2386.85
   DISCCART 261.32 2486.30
   DISCCART 271.77 2585.76
   DISCCART 282.23 2685.21
   DISCCART 292.68 2784.66
   DISCCART 303.13 2884.11
   DISCCART 334.02 2376.64
   DISCCART 347.93 2475.67
   DISCCART 361.85 2574.70
   DISCCART 375.77 2673.72
   DISCCART 389.68 2772.75
   DISCCART 403.60 2871.78
   DISCCART 416.76 2363.54
   DISCCART 434.12 2462.02
   DISCCART 451.49 2560.50
   DISCCART 468.85 2658.98
   DISCCART 486.21 2757.46
   DISCCART 503.58 2855.94
   DISCCART 498.99 2347.55
   DISCCART 519.78 2445.37
   DISCCART 540.57 2543.18
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DISCCART	561.36	2641.00
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DISCCART	602.94	2836.63
DISCCART	604.80	2425.74
DISCCART	629.00	2522.77
DISCCART	653.19	2619.80
DISCCART	677.38	2716.83
DISCCART	701.57	2813.86
DISCCART	689.09	2403.15
DISCCART	716.66	2499.28
DISCCART	744.22	2595.41
DISCCART	771.78	2691.53
DISCCART	799.35	2787.66
DISCCART	772.54	2377.64
DISCCART	803.44	2472.75
DISCCART	834.35	2567.85
DISCCART	865.25	2662.96
DISCCART	896.15	2758.06
DISCCART	855.05	2349.23
DISCCART	889.25	2443.20
DISCCART	923.45	2537.17
DISCCART	957.66	2631.14
DISCCART	991.86	2725.11
DISCCART	973.98	2410.68
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DISCCART	1057.52	2375.22
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DISCCART	1138.86	2557.93
DISCCART	1179.54	2649.28
DISCCART	1183.60	2426.74
DISCCART	1227.44	2516.62
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DISCCART	1267.57	2383.96
DISCCART	1314.52	2472.25
DISCCART	1361.47	2560.55
DISCCART	1350.00	2338.27
DISCCART	1400.00	2424.87
DISCCART	1450.00	2511.47
DISCCART	1430.78	2289.73
DISCCART	1483.77	2374.53
DISCCART	1536.77	2459.34
DISCCART	1509.82	2238.40
DISCCART	1565.74	2321.31
DISCCART	1621.66	2404.21
DISCCART	1587.02	2184.35
DISCCART	1645.80	2265.25
DISCCART	1704.58	2346.15
DISCCART	1662.29	2127.63
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DISCCART	1785.42	2285.23
DISCCART	1735.53	2068.32
DISCCART	1799.81	2144.92
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DISCCART	1873.57	2080.81

DISCCART	1940.48	2155.12
DISCCART	1875.58	1942.22
DISCCART	1945.04	2014.15
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DISCCART	1942.22	1875.58
DISCCART	2014.15	1945.04
DISCCART	2086.09	2014.51
DISCCART	2006.49	1806.65
DISCCART	2080.81	1873.57
DISCCART	2155.12	1940.48
DISCCART	2068.32	1735.53
DISCCART	2144.92	1799.81
DISCCART	2221.53	1864.08
DISCCART	2206.43	1723.85
DISCCART	2285.23	1785.42
DISCCART	2265.25	1645.80
DISCCART	2346.15	1704.58
DISCCART	2321.31	1565.74
DISCCART	2404.21	1621.66
DISCCART	2459.34	1536.77
DISCCART	2511.47	1450.00
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DISCCART	2537.17	-923.45
DISCCART	2631.14	-957.66
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DISCCART	2317.96	-936.52
DISCCART	2410.68	-973.98
DISCCART	2503.40	-1011.44
DISCCART	2596.11	-1048.90
DISCCART	2688.83	-1086.36
DISCCART	2009.80	-894.82
DISCCART	2101.15	-935.49
DISCCART	2192.51	-976.17
DISCCART	2283.86	-1016.84
DISCCART	2375.22	-1057.52
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DISCCART	2557.93	-1138.86
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DISCCART	1797.59	-876.74
DISCCART	1887.47	-920.58
DISCCART	1977.35	-964.42
DISCCART	2067.23	-1008.25
DISCCART	2157.11	-1052.09
DISCCART	2246.99	-1095.93
DISCCART	2336.86	-1139.76
DISCCART	2426.74	-1183.60
DISCCART	2516.62	-1227.44
DISCCART	2606.50	-1271.28
DISCCART	1677.60	-892.00
DISCCART	1765.90	-938.94
DISCCART	1854.19	-985.89
DISCCART	1942.48	-1032.84
DISCCART	2030.78	-1079.78

DISCCART 2119.07 -1126.73
DISCCART 2207.37 -1173.68
DISCCART 2295.66 -1220.63
DISCCART 2383.96 -1267.57
DISCCART 2472.25 -1314.52
DISCCART 2560.55 -1361.47
DISCCART 1558.85 -900.00
DISCCART 1645.45 -950.00
DISCCART 1732.05 -1000.00
DISCCART 1818.65 -1050.00
DISCCART 1905.26 -1100.00
DISCCART 1991.86 -1150.00
DISCCART 2078.46 -1200.00
DISCCART 2165.06 -1250.00
DISCCART 2251.67 -1300.00
DISCCART 2338.27 -1350.00
DISCCART 2424.87 -1400.00
DISCCART 2511.47 -1450.00

ALL RECEPTORS NOT SHOWN DUE TO LENGTH OF FILE, SEE ELECTRONIC VERSION FOR ALL RECEPTORS

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DISCCART -15000.00 -25980.76
DISCCART -7948.79 -12720.72
DISCCART -10598.39 -16960.96
DISCCART -13247.98 -21201.20
DISCCART -15897.58 -25441.44
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DISCCART -17633.56 -24270.51
DISCCART -9234.92 -11820.16
DISCCART -12313.23 -15760.22
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   DISCCART -1046.35 14963.46
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   DISCCART -697.99 19987.82
   DISCCART -872.49 24984.77
   DISCCART -1046.98 29981.72
** Discrete Cartesian Plant Boundary - Primary Receptors
   DISCCART -5675.24 2343.74
   DISCCART 1236.69 2343.74
   DISCCART 3182.77 889.78
   DISCCART 3205.14 -854.98
   DISCCART 744.58 -877.35
   DISCCART 766.95 -2443.16
   DISCCART -15.96 -2465.53
   DISCCART -15.96 -4053.71
   DISCCART -1671.24 -4053.71
   DISCCART -1648.87 -6044.53
   DISCCART -2252.83 -6380.06
   DISCCART -2252.83 -5664.26
   DISCCART -3818.64 -5664.26
   DISCCART -3662.06 -4031.34
   DISCCART -4333.12 -161.55
** Discrete Cartesian Plant Boundary - Intermediate Receptors
   DISCCART -5625.51 2343.74
   DISCCART -5575.79 2343.74
   DISCCART -5526.06 2343.74
   DISCCART -5476.34 2343.74
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DISCCART	-4804.04	717.50
DISCCART	-4827.59	761.45
DISCCART	-4851.13	805.40
DISCCART	-4874.68	849.36
DISCCART	-4898.22	893.31
DISCCART	-4921.77	937.26
DISCCART	-4945.32	981.21
DISCCART	-4968.86	1025.17
DISCCART	-4992.41	1069.12
DISCCART	-5015.95	1113.07
DISCCART	-5039.50	1157.02
DISCCART	-5063.04	1200.98
DISCCART	-5086.59	1244.93
DISCCART	-5110.14	1288.88
DISCCART	-5133.68	1332.83
DISCCART	-5157.23	1376.79
DISCCART	-5180.77	1420.74
DISCCART	-5204.32	1464.69
DISCCART	-5227.87	1508.64
DISCCART	-5251.41	1552.60
DISCCART	-5274.96	1596.55
DISCCART	-5298.50	1640.50
DISCCART	-5322.05	1684.45
DISCCART	-5345.60	1728.41
DISCCART	-5369.14	1772.36
DISCCART	-5392.69	1816.31

```
   DISCCART -5416.23 1860.26
   DISCCART -5439.78 1904.22
   DISCCART -5463.33 1948.17
   DISCCART -5486.87 1992.12
   DISCCART -5510.42 2036.07
   DISCCART -5533.96 2080.03
   DISCCART -5557.51 2123.98
   DISCCART -5581.06 2167.93
   DISCCART -5604.60 2211.88
   DISCCART -5628.15 2255.84
   DISCCART -5651.69 2299.79
RE FINISHED
**
*****************************************
** ISCST3 Meteorology Pathway
*****************************************
**
**
ME STARTING
** Met File Path: d:\MET\
   INPUTFIL d:\met\PBIPBI87.MET
   ANEMHGHT 33 FEET
   SURFDATA 12844 1987 WEST-PALM-BCH
   UAIRDATA 12844 1987 WEST-PALM-BCH
ME FINISHED
**
*****************************************
** ISCST3 Output Pathway
*****************************************
**
**
OU STARTING
   RECTABLE ALLAVE FIRST
   RECTABLE 1 FIRST
   RECTABLE 3 FIRST
   RECTABLE 8 FIRST
   RECTABLE 24 FIRST
** Auto-Generated Plotfiles
** Plotfile Path: D:\martin\martin1.IS\

OU FINISHED
```

EXAMPLE CALPUFF INPUT FILE

```
FPL MARTIN PROPOSED CTS, COMBINED CYCLE, FUEL OIL, BASE LOAD, 35DEG F
FOR SIGNIFICANT IMPACT ANALYSIS AND AQRV ANALYSES AT EVERGLADES NATIONAL PARK
REFINED CALPUFF ANALYSIS USING SOUTH FLORIDA CALMET DOMAIN
--------------- Run title (3 lines) --------------------------------------

          CALPUFF MODEL CONTROL FILE
          --------------------------


-------------------------------------------------------------------------------

INPUT GROUP: 0 -- Input and Output File Names

   Number of CALMET.DAT files for run (NMETDAT)
                        Default: 1      ! NMETDAT =   6   !

---------------
Default Name  Type        File Name
------------  ----        --------
CALMET.DAT    input    * METDAT =          *
   or
ISCMET.DAT    input    * ISCDAT =          *
   or
PLMMET.DAT    input    * PLMDAT =          *
   or
PROFILE.DAT   input    * PRFDAT =          *
SURFACE.DAT   input    * SFCDAT =          *
RESTARTB.DAT  input    * RSTARTB=          *
-------------------------------------------------------------------------------
CALPUFF.LST   output   ! PUFLST =PUFFFOCC.LST  !
CONC.DAT      output   ! CONDAT =PUFFFOCC.CON  !
DFLX.DAT      output   ! DFDAT  =PUFFFOCC.DRY  !
WFLX.DAT      output   ! WFDAT  =PUFFFOCC.WET  !

VISB.DAT      output   ! VISDAT =VISB.DAT  !
RESTARTE.DAT  output   * RSTARTE=          *
-------------------------------------------------------------------------------
Emission Files
---------------
PTEMARB.DAT   input    * PTDAT  =          *
VOLEM.DAT     input    * VOLDAT =          *
BAEMARB.DAT   input    * ARDAT  =          *
LNEMARB.DAT   input    * LNDAT  =          *
-------------------------------------------------------------------------------
Other Files
-----------
OZONE.DAT     input    ! OZDAT  =O3ENP90.DAT  !
VD.DAT        input    * VDDAT  =          *
CHEM.DAT      input    * CHEMDAT=          *
HILL.DAT      input    * HILDAT=           *
HILLRCT.DAT   input    * RCTDAT=           *
COASTLN.DAT   input    * CSTDAT=           *
FLUXBDY.DAT   input    * BDYDAT=           *
DEBUG.DAT     output   * DEBUG =           *
MASSFLX.DAT   output   * FLXDAT=           *
MASSBAL.DAT   output   * BALDAT=           *
-------------------------------------------------------------------------------
All file names will be converted to lower case if LCFILES = T
Otherwise, if LCFILES = F, file names will be converted to UPPER CASE
```

```
        T = lower case      ! LCFILES = T !
        F = UPPER CASE
NOTE: (1) file/path names can be up to 70 characters in length

!END!

-------------
Subgroup (0a)
-------------

 The following CALMET.DAT filenames are processed in sequence if NMETDAT>1

Default Name  Type          File Name
------------  ----          ---------
 none       input   ! METDAT=E:\CALMET\ENP\MET0102.DAT     !  !END!
 none       input   ! METDAT=E:\CALMET\ENP\MET0304.DAT     !  !END!
 none       input   ! METDAT=E:\CALMET\ENP\MET0506.DAT     !  !END!
 none       input   ! METDAT=E:\CALMET\ENP\MET0708.DAT     !  !END!
 none       input   ! METDAT=E:\CALMET\ENP\MET0910.DAT     !  !END!
 none       input   ! METDAT=E:\CALMET\ENP\MET1112.DAT     !  !END!


--------------------------------------------------------------------------------

INPUT GROUP: 1 -- General run control parameters
--------------


   Option to run all periods found
   in the met. file     (METRUN)   Default: 0       ! METRUN =   0  !

       METRUN = 0 - Run period explicitly defined below
       METRUN = 1 - Run all periods in met. file

    Starting date:   Year (IBYR) -- No default       ! IBYR =  1990  !
    (used only if   Month (IBMO) -- No default       ! IBMO =  1  !
     METRUN = 0)        Day (IBDY) -- No default       ! IBDY =  6  !
                   Hour (IBHR) -- No default       ! IBHR =  0  !

    Length of run (hours) (IRLG) -- No default       ! IRLG =  8616  !

    Number of chemical species (NSPEC)
                              Default: 5      ! NSPEC =  7   !

    Number of chemical species
    to be emitted  (NSE)           Default: 3      ! NSE =  4   !

    Flag to stop run after
    SETUP phase (ITEST)            Default: 2       ! ITEST =  2   !
    (Used to allow checking
    of the model inputs, files, etc.)
         ITEST = 1 - STOPS program after SETUP phase
         ITEST = 2 - Continues with execution of program
                  after SETUP

    Restart Configuration:

       Control flag (MRESTART)     Default: 0       ! MRESTART =  0   !
```

```
         0 = Do not read or write a restart file
         1 = Read a restart file at the beginning of
             the run
         2 = Write a restart file during run
         3 = Read a restart file at beginning of run
             and write a restart file during run

       Number of periods in Restart
       output cycle (NRESPD)       Default: 0      ! NRESPD =  0   !

         0 = File written only at last period
        >0 = File updated every NRESPD periods

     Meteorological Data Format (METFM)
                              Default: 1       ! METFM =  1   !

         METFM = 1 - CALMET binary file (CALMET.MET)
         METFM = 2 - ISC ASCII file (ISCMET.MET)
         METFM = 3 - AUSPLUME ASCII file (PLMMET.MET)
         METFM = 4 - CTDM plus tower file (PROFILE.DAT) and
                  surface parameters file (SURFACE.DAT)

     PG sigma-y is adjusted by the factor (AVET/PGTIME)**0.2
     Averaging Time (minutes) (AVET)
                              Default: 60.0    ! AVET = 60. !
     PG Averaging Time (minutes) (PGTIME)
                              Default: 60.0    ! PGTIME = 60. !


!END!


-------------------------------------------------------------------------------

INPUT GROUP: 2 -- Technical options
--------------


     Vertical distribution used in the
     near field (MGAUSS)              Default: 1     ! MGAUSS =  1   !
       0 = uniform
       1 = Gaussian

     Terrain adjustment method
     (MCTADJ)                      Default: 3     ! MCTADJ =  3   !
       0 = no adjustment
       1 = ISC-type of terrain adjustment
       2 = simple, CALPUFF-type of terrain
           adjustment
       3 = partial plume path adjustment

     Subgrid-scale complex terrain
     flag (MCTSG)                   Default: 0     ! MCTSG =  0   !
       0 = not modeled
       1 = modeled

     Near-field puffs modeled as
     elongated 0 (MSLUG)              Default: 0     ! MSLUG =  0   !
```

```
  0 = no
  1 = yes (slug model used)

Transitional plume rise modeled ?
(MTRANS)                    Default: 1     ! MTRANS =  1   !
  0 = no  (i.e., final rise only)
  1 = yes (i.e., transitional rise computed)

Stack tip downwash? (MTIP)         Default: 1     ! MTIP =  1  !
  0 = no  (i.e., no stack tip downwash)
  1 = yes (i.e., use stack tip downwash)

Vertical wind shear modeled above
stack top? (MSHEAR)               Default: 0     ! MSHEAR =  1  !
  0 = no  (i.e., vertical wind shear not modeled)
  1 = yes (i.e., vertical wind shear modeled)

Puff splitting allowed? (MSPLIT)     Default: 0     ! MSPLIT =  0  !
  0 = no (i.e., puffs not split)
  1 = yes (i.e., puffs are split)

Chemical mechanism flag (MCHEM)      Default: 1     ! MCHEM =  1   !
  0 = chemical transformation not
      modeled
  1 = transformation rates computed
      internally (MESOPUFF II scheme)
  2 = user-specified transformation
      rates used
  3 = transformation rates computed
      internally (RIVAD/ARM3 scheme)

Wet removal modeled ? (MWET)        Default: 1     ! MWET =  1   !
  0 = no
  1 = yes

Dry deposition modeled ? (MDRY)      Default: 1     ! MDRY =  1   !
  0 = no
  1 = yes
  (dry deposition method specified
   for each species in Input Group 3)

Method used to compute dispersion
coefficients (MDISP)              Default: 3     ! MDISP =  4   !

  1 = dispersion coefficients computed from measured values
      of turbulence, sigma v, sigma w
  2 = dispersion coefficients from internally calculated
      sigma v, sigma w using micrometeorological variables
      (u*, w*, L, etc.)
  3 = PG dispersion coefficients for RURAL areas (computed using
      the ISCST multi-segment approximation) and MP coefficients in
      urban areas
  4 = same as 3 except PG coefficients computed using
      the MESOPUFF II eqns.
  5 = CTDM sigmas used for stable and neutral conditions.
      For unstable conditions, sigmas are computed as in
      MDISP = 3, described above.  MDISP = 5 assumes that
      measured values are read
```

Sigma-v/sigma-theta, sigma-w measurements used? (MTURBVW)
(Used only if MDISP = 1 or 5) Default: 3 ! MTURBVW = 0 !
  1 = use sigma-v or sigma-theta measurements
    from PROFILE.DAT to compute sigma-y
    (valid for METFM = 1, 2, 3, 4)
  2 = use sigma-w measurements
    from PROFILE.DAT to compute sigma-z
    (valid for METFM = 1, 2, 3, 4)
  3 = use both sigma-(v/theta) and sigma-w
    from PROFILE.DAT to compute sigma-y and sigma-z
    (valid for METFM = 1, 2, 3, 4)
  4 = use sigma-theta measurements
    from PLMMET.DAT to compute sigma-y
    (valid only if METFM = 3)

Back-up method used to compute dispersion
when measured turbulence data are
missing (MDISP2) Default: 3 ! MDISP2 = 4 !
(used only if MDISP = 1 or 5)
  2 = dispersion coefficients from internally calculated
    sigma v, sigma w using micrometeorological variables
    (u*, w*, L, etc.)
  3 = PG dispersion coefficients for RURAL areas (computed using
    the ISCST multi-segment approximation) and MP coefficients in
    urban areas
  4 = same as 3 except PG coefficients computed using
    the MESOPUFF II eqns.

PG sigma-y,z adj. for roughness? Default: 0 ! MROUGH = 0 !
(MROUGH)
  0 = no
  1 = yes

Partial plume penetration of Default: 1 ! MPARTL = 1 !
elevated inversion?
(MPARTL)
  0 = no
  1 = yes

Strength of temperature inversion Default: 0 ! MTINV = 0 !
provided in PROFILE.DAT extended records?
(MTINV)
  0 = no (computed from measured/default gradients)
  1 = yes

PDF used for dispersion under convective conditions?
Default: 0 ! MPDF = 0 !
(MPDF)
  0 = no
  1 = yes

Sub-Grid TIBL module used for shore line?
Default: 0 ! MSGTIBL = 0 !
(MSGTIBL)
  0 = no
  1 = yes

```
    Test options specified to see if
    they conform to regulatory
    values? (MREG)               Default: 1     ! MREG =  0  !

      0 = NO checks are made
      1 = Technical options must conform to USEPA values
                 METFM    1
                 AVET     60. (min)
                 MGAUSS   1
                 MCTADJ   3
                 MTRANS   1
                 MTIP     1
                 MCHEM    1 (if modeling SOx, NOx)
                 MWET     1
                 MDRY     1
                 MDISP    3
                 MROUGH   0
                 MPARTL   1
                 SYTDEP   550. (m)
                 MHFTSZ   0


!END!


-------------------------------------------------------------------------------

INPUT GROUP: 3a, 3b -- Species list
-------------------

-------------
Subgroup (3a)
-------------

  The following species are modeled:

! CSPEC =        SO2 !       !END!
! CSPEC =        SO4 !       !END!
! CSPEC =        NOX !       !END!
! CSPEC =       HNO3 !       !END!
! CSPEC =        NO3 !       !END!
! CSPEC =       PM10 !       !END!
! CSPEC =         CO !       !END!

                                          Dry            OUTPUT GROUP
   SPECIES        MODELED           EMITTED      DEPOSITED              NUMBER
    NAME      (0=NO, 1=YES)   (0=NO, 1=YES)   (0=NO,               (0=NONE,
  (Limit: 12                           1=COMPUTED-GAS        1=1st CGRUP,
   Characters                           2=COMPUTED-PARTICLE   2=2nd CGRUP,
   in length)                          3=USER-SPECIFIED)     3= etc.)

!      SO2  =        1,            1,          1,             0  !
!      SO4  =        1,            0,          2,             0  !
!      NOX  =        1,            1,          1,             0  !
!     HNO3  =        1,            0,          1,             0  !
!      NO3  =        1,            0,          2,             0  !
!     PM10  =        1,            1,          2,             0  !
!       CO  =        1,            1,          0,             0  !
```

```
!END!

-------------
Subgroup (3b)
-------------
  The following names are used for Species-Groups in which results
  for certain species are combined (added) prior to output.  The
  CGRUP name will be used as the species name in output files.
  Use this feature to model specific particle-size distributions
  by treating each size-range as a separate species.
  Order must be consistent with 3(a) above.



-------------------------------------------------------------------------------


INPUT GROUP: 4 -- Grid control parameters
--------------


METEOROLOGICAL grid:

        No. X grid cells (NX)      No default     ! NX =  90   !
        No. Y grid cells (NY)      No default     ! NY =  94   !
      No. vertical layers (NZ)      No default     ! NZ =  9    !

       Grid spacing (DGRIDKM)      No default     ! DGRIDKM = 5. !
                                   Units: km

            Cell face heights
               (ZFACE(nz+1))       No defaults
                                   Units: m
  ! ZFACE = 0., 20., 50., 100., 200., 500., 1000., 1500., 2500., 3500. !

        Reference Coordinates
       of SOUTHWEST corner of
           grid cell(1, 1):

       X coordinate (XORIGKM)      No default     ! XORIGKM = 250. !
       Y coordinate (YORIGKM)      No default     ! YORIGKM = 2628. !
                                  Units: km

           UTM zone (IUTMZN)       No default     ! IUTMZN =  17   !

  Reference coordinates of CENTER
     of the domain (used in the
   calculation of solar elevation
                angles)

       Latitude  (deg.) (XLAT)     No default     ! XLAT  = 26.  !
      Longitude (deg.) (XLONG)     No default     ! XLONG = 81.  !
        Time zone       (XTZ)      No default     ! XTZ   = 5.0  !
    (PST=8, MST=7, CST=6, EST=5)
```

Computational grid:

The computational grid is identical to or a subset of the MET. grid. The lower left (LL) corner of the computational grid is at grid point (IBCOMP, JBCOMP) of the MET. grid. The upper right (UR) corner of the computational grid is at grid point (IECOMP, JECOMP) of the MET. grid. The grid spacing of the computational grid is the same as the MET. grid.

```
   X index of LL corner (IBCOMP)    No default    ! IBCOMP =  1   !
         (1 <= IBCOMP <= NX)

   Y index of LL corner (JBCOMP)    No default    ! JBCOMP =  1   !
         (1 <= JBCOMP <= NY)


   X index of UR corner (IECOMP)    No default    ! IECOMP =  90   !
         (1 <= IECOMP <= NX)

   Y index of UR corner (JECOMP)    No default    ! JECOMP =  94   !
         (1 <= JECOMP <= NY)
```

SAMPLING GRID (GRIDDED RECEPTORS):

The lower left (LL) corner of the sampling grid is at grid point (IBSAMP, JBSAMP) of the MET. grid. The upper right (UR) corner of the sampling grid is at grid point (IESAMP, JESAMP) of the MET. grid. The sampling grid must be identical to or a subset of the computational grid. It may be a nested grid inside the computational grid. The grid spacing of the sampling grid is DGRIDKM/MESHDN.

```
   Logical flag indicating if gridded
   receptors are used (LSAMP)       Default: T    ! LSAMP = F !
   (T=yes, F=no)

   X index of LL corner (IBSAMP)    No default    ! IBSAMP =  0   !
    (IBCOMP <= IBSAMP <= IECOMP)

   Y index of LL corner (JBSAMP)    No default    ! JBSAMP =  0   !
    (JBCOMP <= JBSAMP <= JECOMP)


   X index of UR corner (IESAMP)    No default    ! IESAMP =  90  !
    (IBCOMP <= IESAMP <= IECOMP)

   Y index of UR corner (JESAMP)    No default    ! JESAMP =  94  !
    (JBCOMP <= JESAMP <= JECOMP)


  Nesting factor of the sampling
   grid (MESHDN)                 Default: 1    ! MESHDN =  1  !
   (MESHDN is an integer >= 1)
```

!END!

```
INPUT GROUP: 5 -- Output Options
--------------
                          *                *
  FILE              DEFAULT VALUE       VALUE THIS RUN
  ----              -------------       -------------

 Concentrations (ICON)        1           ! ICON = 1  !
 Dry Fluxes (IDRY)            1           ! IDRY = 1  !
 Wet Fluxes (IWET)            1           ! IWET = 1  !
 Relative Humidity (IVIS)     1           ! IVIS = 1  !
  (relative humidity file is
   required for visibility
   analysis)
 Use data compression option in output file?
 (LCOMPRS)                 Default: T     ! LCOMPRS = F !

 *
  0 = Do not create file, 1 = create file


  DIAGNOSTIC MASS FLUX OUTPUT OPTIONS:

    Mass flux across specified boundaries
    for selected species reported hourly?
    (IMFLX)                Default: 0     ! IMFLX = 0 !
     0 = no
     1 = yes (FLUXBDY.DAT and MASSFLX.DAT filenames
          are specified in Input Group 0)

    Mass balance for each species
    reported hourly?
    (IMBAL)                Default: 0     ! IMBAL = 0 !
     0 = no
     1 = yes (MASSBAL.DAT filename is
        specified in Input Group 0)


  LINE PRINTER OUTPUT OPTIONS:

    Print concentrations (ICPRT)   Default: 0    ! ICPRT = 0  !
    Print dry fluxes (IDPRT)       Default: 0    ! IDPRT = 0  !
    Print wet fluxes (IWPRT)       Default: 0    ! IWPRT = 0  !
    (0 = Do not print, 1 = Print)

    Concentration print interval
    (ICFRQ) in hours          Default: 1     ! ICFRQ = 24  !
    Dry flux print interval
    (IDFRQ) in hours          Default: 1     ! IDFRQ = 1  !
    Wet flux print interval
    (IWFRQ) in hours          Default: 1     ! IWFRQ = 1  !

    Units for Line Printer Output
    (IPRTU)                 Default: 1     ! IPRTU = 3  !
             for          for
          Concentration   Deposition
      1 =     g/m**3       g/m**2/s
```

2 = mg/m**3 mg/m**2/s
3 = ug/m**3 ug/m**2/s
4 = ng/m**3 ng/m**2/s
5 = Odour Units

Messages tracking progress of Default: 1 ! IMESG = 1 !
run written to the screen ?
(IMESG) -- 0=no, 1=yes

SPECIES (or GROUP for combined species) LIST FOR OUTPUT OPTIONS

	---- CONCENTRATIONS ----		------ DRY FLUXES ------		------ WET FLUXES ------		-- MASS FLUX --	
SPECIES /GROUP	PRINTED?	SAVED ON DISK?	PRINTED?	SAVED ON DISK?	PRINTED?	SAVED ON DISK?	SAVE	
! SO2 =	0,	1,	0,	1,	0,	1,	0	!
! SO4 =	0,	1,	0,	1,	0,	1,	0	!
! NOX =	0,	1,	0,	1,	0,	1,	0	!
! HNO3 =	0,	1,	0,	1,	0,	1,	0	!
! NO3 =	0,	1,	0,	1,	0,	1,	0	!
! PM10 =	0,	1,	0,	1,	0,	1,	0	!
! CO =	0,	1,	0,	1,	0,	1,	0	!

OPTIONS FOR PRINTING "DEBUG" QUANTITIES (much output)

Logical for debug output
(LDEBUG) Default: F ! LDEBUG = F !

First puff to track
(IPFDEB) Default: 1 ! IPFDEB = 1 !

Number of puffs to track
(NPFDEB) Default: 1 ! NPFDEB = 1 !

Met. period to start output
(NN1) Default: 1 ! NN1 = 1 !

Met. period to end output
(NN2) Default: 10 ! NN2 = 10 !

!END!

INPUT GROUP: 6a, 6b, & 6c -- Subgrid scale complex terrain inputs
----

Subgroup (6a)

Number of terrain features (NHILL) Default: 0 ! NHILL = 0 !

Number of special complex terrain
receptors (NCTREC) Default: 0 ! NCTREC = 0 !

```
     Terrain and CTSG Receptor data for
     CTSG hills input in CTDM format ?
     (MHILL)                     No Default    ! MHILL =  0   !
     1 = Hill and Receptor data created
        by CTDM processors & read from
        HILL.DAT and HILLRCT.DAT files
     2 = Hill data created by OPTHILL &
        input below in Subgroup (6b);
        Receptor data in Subgroup (6c)

     Factor to convert horizontal dimensions  Default: 1.0   ! XHILL2M = 1. !
     to meters (MHILL=1)

     Factor to convert vertical dimensions    Default: 1.0   ! ZHILL2M = 1. !
     to meters (MHILL=1)

     X-origin of CTDM system relative to      No Default     ! XCTDMKM = 0.0E00 !
     CALPUFF coordinate system, in Kilometers (MHILL=1)

     Y-origin of CTDM system relative to      No Default     ! YCTDMKM = 0.0E00 !
     CALPUFF coordinate system, in Kilometers (MHILL=1)

! END !

---------------
Subgroup (6b)
---------------

                 1 **
   HILL information


HILL     XC     YC    THETAH ZGRID RELIEF   EXPO 1   EXPO 2  SCALE 1  SCALE 2  AMAX1   AMA
 NO.    (km)   (km)   (deg.) (m)    (m)     (m)      (m)      (m)      (m)      (m)
----    ----   ----   ------ ----- ------  ------   ------  -------  -------  -----   -----

---------------
Subgroup (6c)
---------------

   COMPLEX TERRAIN RECEPTOR INFORMATION

                 XRCT      YRCT     ZRCT       XHH
                 (km)      (km)     (m)
                ------    -----    ------     ----


--------------------
1
   Description of Complex Terrain Variables:
      XC, YC  = Coordinates of center of hill
      THETAH  = Orientation of major axis of hill (clockwise from
                North)
      ZGRID   = Height of the  0  of the grid above mean sea
                level
      RELIEF  = Height of the crest of the hill above the grid elevation
      EXPO 1  = Hill-shape exponent for the major axis
      EXPO 2  = Hill-shape exponent for the major axis
```

```
        SCALE 1 = Horizontal length scale along the major axis
        SCALE 2 = Horizontal length scale along the minor axis
        AMAX    = Maximum allowed axis length for the major axis
        BMAX    = Maximum allowed axis length for the major axis

        XRCT, YRCT = Coordinates of the complex terrain receptors
        ZRCT    = Height of the ground (MSL) at the complex terrain
                  Receptor
        XHH     = Hill number associated with each complex terrain receptor
                  (NOTE: MUST BE ENTERED AS A REAL NUMBER)

  **
   NOTE: DATA for each hill and CTSG receptor are treated as a separate
         input subgroup and therefore must end with an input group terminator.

-------------------------------------------------------------------------------


INPUT GROUP: 7 -- Chemical parameters for dry deposition of gases
--------------

     SPECIES    DIFFUSIVITY    ALPHA STAR    REACTIVITY   MESOPHYLL RESISTANCE    HENRY'S LAW CO
      NAME      (cm**2/s)                                      (s/cm)              (dimensionless)
     -------    -----------    ----------    ----------   --------------------   ----------------

!       SO2 =     0.1509,       1000.,          8.,              0.,              0.04 !
!       NOX =     0.1656,          1.,          8.,              5.,               3.5 !
!      HNO3 =     0.1628,          1.,         18.,              0.,        0.00000008 !

!END!


-------------------------------------------------------------------------------


INPUT GROUP: 8 -- Size parameters for dry deposition of particles
--------------

    For SINGLE SPECIES, the mean and standard deviation are used to
    compute a deposition velocity for NINT (see group 9) size-ranges,
    and these are then averaged to obtain a mean deposition velocity.

    For GROUPED SPECIES, the size distribution should be explicitly
    specified (by the 'species' in the group), and the standard deviation
    for each should be entered as 0.  The model will then use the
    deposition velocity for the stated mean diameter.

     SPECIES     GEOMETRIC MASS MEAN        GEOMETRIC STANDARD
      NAME           DIAMETER                   DEVIATION
                    (microns)                   (microns)
     -------     -------------------        -----------------
!       SO4 =          0.48,                     2.  !
!       NO3 =          0.48,                     2.  !
!      PM10 =          0.48,                     2.  !

!END!
```

```
--------------------------------------------------------------------------------

INPUT GROUP: 9 -- Miscellaneous dry deposition parameters
---------------

     Reference cuticle resistance (s/cm)
     (RCUTR)                     Default: 30   ! RCUTR = 30. !
     Reference ground resistance  (s/cm)
     (RGR)                       Default: 10   !  RGR = 10. !
     Reference pollutant reactivity
     (REACTR)                    Default: 8    ! REACTR = 8. !

     Number of particle-size intervals used to
     evaluate effective particle deposition velocity
     (NINT)                      Default: 9    !  NINT =  9  !

     Vegetation state in unirrigated areas
     (IVEG)                      Default: 1    !  IVEG =  1  !
        IVEG=1 for active and unstressed vegetation
        IVEG=2 for active and stressed vegetation
        IVEG=3 for inactive vegetation

!END!


--------------------------------------------------------------------------------

INPUT GROUP: 10 -- Wet Deposition Parameters
---------------


                 Scavenging Coefficient -- Units: (sec)**(-1)

       Pollutant    Liquid Precip.    Frozen Precip.
       ---------    --------------    --------------
!        SO2 =        3.0E-05,          0.0E00 !
!        SO4 =        1.0E-04,          3.0E-05 !
!       HNO3 =        6.0E-05,          0.0E00 !
!        NO3 =        1.0E-04,          3.0E-05 !
!       PM10 =        1.0E-04,          3.0E-05 !

!END!


--------------------------------------------------------------------------------

INPUT GROUP: 11 -- Chemistry Parameters
---------------

     Ozone data input option (MOZ)    Default: 1         ! MOZ =  1  !
     (Used only if MCHEM = 1 or 3)
        0 = use a constant background ozone value
        1 = read hourly ozone concentrations from
            the OZONE.DAT data file
```

```
   Background ozone concentration
   (BCKO3) in ppb              Default: 80.      ! BCKO3 = 80. !
   (Used only if MCHEM = 1 or 3 and
    MOZ = 0 or (MOZ = 1 and all hourly
    O3 data missing)

   Background ammonia concentration
   (BCKNH3) in ppb             Default: 10.      ! BCKNH3 = 1. !

   Nighttime SO2 loss rate (RNITE1)
   in percent/hour             Default: 0.2      ! RNITE1 = 0.2 !

   Nighttime NOx loss rate (RNITE2)
   in percent/hour             Default: 2.0      ! RNITE2 = 2. !

   Nighttime HNO3 formation rate (RNITE3)
   in percent/hour             Default: 2.0      ! RNITE3 = 2. !

!END!


-------------------------------------------------------------------------------

INPUT GROUP: 12 -- Misc. Dispersion and Computational Parameters
---------------

   Horizontal size of puff (m) beyond which
   time-dependent dispersion equations (Heffter)
   are used to determine sigma-y and
   sigma-z (SYTDEP)                    Default: 550.   ! SYTDEP = 5.5E02 !

   Switch for using Heffter equation for sigma z
   as above (0 = Not use Heffter; 1 = use Heffter
   (MHFTSZ)                         Default: 0      ! MHFTSZ =  0   !

   Stability class used to determine plume
   growth rates for puffs above the boundary
   layer (JSUP)                     Default: 5      ! JSUP =  5   !

   Vertical dispersion constant for stable
   conditions (k1 in Eqn. 2.7-3)  (CONK1)     Default: 0.01   ! CONK1 = 0.01 !

   Vertical dispersion constant for neutral/
   unstable conditions (k2 in Eqn. 2.7-4)
   (CONK2)                          Default: 0.1    ! CONK2 = 0.1 !

   Factor for determining Transition-point from
   Schulman-Scire to Huber-Snyder Building Downwash
   scheme (SS used for Hs < Hb + TBD * HL)
   (TBD)                            Default: 0.5    ! TBD = 0.5 !
     TBD < 0   ==> always use Huber-Snyder
     TBD = 1.5 ==> always use Schulman-Scire
     TBD = 0.5 ==> ISC Transition-point

   Range of land use categories for which
   urban dispersion is assumed
   (IURB1, IURB2)                   Default: 10     ! IURB1 =  10  !
```

```
                              19    ! IURB2 =  19  !

Site characterization parameters for single-point Met data files ---------
(needed for METFM = 2,3,4)

  Land use category for modeling domain
  (ILANDUIN)                   Default: 20     ! ILANDUIN =  20  !

  Roughness length (m) for modeling domain
  (Z0IN)                     Default: 0.25   ! Z0IN = 0.25 !

  Leaf area index for modeling domain
  (XLAIIN)                   Default: 3.0    ! XLAIIN = 3. !

  Elevation above sea level (m)
  (ELEVIN)                   Default: 0.0    ! ELEVIN = 0. !

  Latitude (degrees) for met location
  (XLATIN)                   Default: -999.  ! XLATIN = -999. !

  Longitude (degrees) for met location
  (XLONIN)                   Default: -999.  ! XLONIN = -999. !

Specialized information for interpreting single-point Met data files -----

  Anemometer height (m) (Used only if METFM = 2,3)
  (ANEMHT)                     Default: 10.    ! ANEMHT = 10. !

  Form of lateral turbulance data in PROFILE.DAT file
  (Used only if METFM = 4 or MTURBVW = 1 or 3)
  (ISIGMAV)                  Default: 1      ! ISIGMAV =  2  !
     0 = read sigma-theta
     1 = read sigma-v

  Choice of mixing heights (Used only if METFM = 4)
  (IMIXCTDM)                   Default: 0      ! IMIXCTDM =  0  !
     0 = read PREDICTED mixing heights
     1 = read OBSERVED mixing heights

Maximum length of a slug (met. grid units)
(XMXLEN)                       Default: 1.0    ! XMXLEN = 1. !

Maximum travel distance of a puff/slug (in
grid units) during one sampling step
(XSAMLEN)                      Default: 1.0    ! XSAMLEN = 1. !

Maximum Number of slugs/puffs release from
one source during one time step
(MXNEW)                        Default: 99     ! MXNEW =  99   !

Maximum Number of sampling steps for
one puff/slug during one time step
(MXSAM)                        Default: 99     ! MXSAM =  99   !

Number of iterations used when computing
the transport wind for a sampling step
that includes gradual rise (for CALMET
and PROFILE winds)
```

```
(NCOUNT)                          Default: 2      ! NCOUNT =  2   !

Minimum sigma y for a new puff/slug (m)
(SYMIN)                         Default: 1.0    ! SYMIN = 1.  !

Minimum sigma z for a new puff/slug (m)
(SZMIN)                         Default: 1.0    ! SZMIN = 1.  !

Default minimum turbulence velocities
sigma-v and sigma-w for each
stability class (m/s)
(SVMIN(6) and SWMIN(6))    Default SVMIN : .50,  .50,  .50,  .50,  .50,  .50
                    Default SWMIN : .20,  .12,  .08,  .06,  .03,  .016

                 Stability Class :  A     B     C     D     E     F
                                   ---   ---   ---   ---   ---   ---
                      ! SVMIN = 0.500, 0.500, 0.500, 0.500, 0.500, 0.500!
                      ! SWMIN = 0.200, 0.120, 0.080, 0.060, 0.030, 0.016!

Divergence criterion for dw/dz across puff
used to initiate adjustment for horizontal
convergence (1/s)
Partial adjustment starts at CDIV(1), and
full adjustment is reached at CDIV(2)
(CDIV(2))                      Default: 0.0,0.0  ! CDIV = 0., 0. !

Minimum wind speed (m/s) allowed for
non-calm conditions. Also used as minimum
speed returned when using power-law
extrapolation toward surface
(WSCALM)                         Default: 0.5    ! WSCALM = 0.5 !

Maximum mixing height (m)
(XMAXZI)                        Default: 3000.  ! XMAXZI = 3000. !

Minimum mixing height (m)
(XMINZI)                       Default: 50.    ! XMINZI = 50. !

Default wind speed classes --
5 upper bounds (m/s) are entered;
the 6th class has no upper limit
(WSCAT(5))                  Default   :
                   ISC RURAL : 1.54, 3.09, 5.14, 8.23, 10,8 (10.8+)

                Wind Speed Class :  1     2     3     4     5     6
                                   ---   ---   ---   ---   ---   ---
                    ! WSCAT = 1.54, 3.09, 5.14, 8.23, 10.80 !

Default wind speed profile power-law
exponents for stabilities 1-6
(PLX0(6))                  Default   : ISC RURAL values
                   ISC RURAL : .07, .07, .10, .15, .35, .55
                   ISC URBAN : .15, .15, .20, .25, .30, .30

                 Stability Class :  A     B     C     D     E     F
                                   ---   ---   ---   ---   ---   ---
                      ! PLX0 = 0.07, 0.07, 0.10, 0.15, 0.35, 0.55 !
```

```
    Default potential temperature gradient
    for stable classes E, F (degK/m)
    (PTG0(2))                 Default: 0.020, 0.035
                            ! PTG0 = 0.020,   0.035 !

    Default plume path coefficients for
    each stability class (used when option
    for partial plume height terrain adjustment
    is selected -- MCTADJ=3)
    (PPC(6))            Stability Class :  A    B    C    D    E    F
                        Default  PPC : .50,  .50,  .50,  .50,  .35,  .35
                                       ---  ---  ---  ---  ---  ---
                            !  PPC = 0.50, 0.50, 0.50, 0.50, 0.35, 0.35 !

    Slug-to-puff transition criterion factor
    equal to sigma-y/length of slug
    (SL2PF)                   Default: 10.       ! SL2PF = 10. !

    Puff-splitting control variables ------------------------

      Number of puffs that result every time a puff
      is split - nsplit=2 means that 1 puff splits
      into 2
      (NSPLIT)                Default:   3       ! NSPLIT =  3  !

      Time(s) of a day when split puffs are eligible to
      be split once again; this is typically set once
      per day, around sunset before nocturnal shear develops.
      24 values: 0 is midnight (00:00) and 23 is 11 PM (23:00)
      0=do not re-split    1=eligible for re-split
      (IRESPLIT(24))            Default:  Hour 17 = 1
      !  IRESPLIT = 0,0,0,0,0,0,0,0,0,0,0,0,0,0,0,0,0,1,0,0,0,0,0,0 !

      Split is allowed only if last hour's mixing
      height (m) exceeds a minimum value
      (ZISPLIT)               Default: 100.      ! ZISPLIT = 100. !

      Split is allowed only if ratio of last hour's
      mixing ht to the maximum mixing ht experienced
      by the puff is less than a maximum value (this
      postpones a split until a nocturnal layer develops)
      (ROLDMAX)                 Default: 0.25      ! ROLDMAX = 0.25 !

    Integration control variables ------------------------

      Fractional convergence criterion for numerical SLUG
      sampling integration
      (EPSSLUG)                 Default:   1.0e-04  ! EPSSLUG = 1.0E-04 !

      Fractional convergence criterion for numerical AREA
      source integration
      (EPSAREA)                 Default:   1.0e-06  ! EPSAREA = 1.0E-06 !

      Trajectory step-length (m) used for numerical rise
      integration
      (DSRISE)                  Default:   1.0     ! DSRISE = 1. !

!END!
```

```
--------------------------------------------------------------------------------

INPUT GROUPS: 13a, 13b, 13c, 13d -- Point source parameters
--------------------------------

---------------
Subgroup (13a)
---------------

     Number of point sources with
     parameters provided below      (NPT1)  No default  !  NPT1 = 2  !

     Units used for point source
     emissions below              (IPTU)  Default: 1  !  IPTU =   1  !
          1 =      g/s
          2 =      kg/hr
          3 =      lb/hr
          4 =    tons/yr
          5 =    Odour Unit * m**3/s  (vol. flux of odour compound)
          6 =    Odour Unit * m**3/min
          7 =    metric tons/yr

     Number of source-species
     combinations with variable
     emissions scaling factors
     provided below in (13d)       (NSPT1) Default: 0  !  NSPT1 =  0  !

     Number of point sources with
     variable emission parameters
     provided in external file      (NPT2)  No default  !  NPT2 =  0  !

     (If NPT2 > 0, these point
     source emissions are read from
     the file: PTEMARB.DAT)

!END!

---------------
Subgroup (13b)
---------------
                               a
          POINT SOURCE: CONSTANT DATA
          -----------------------------
                                                            b        c

  Source     X UTM     Y UTM     Stack  Base     Stack    Exit  Exit    Bldg.  Emission
   No.    Coordinate Coordinate Height Elevation Diameter  Vel.  Temp.   Dwash    Rates
            (km)      (km)       (m)      (m)      (m)   (m/s) (deg. K)
  ------  ---------- ---------- ------  ------   -------- ----- --------
4 CT UNITS, COMBINED CYCLE MODE- FUEL OIL
WORSE CASE EMISSIONS ARE FOR BASE LOAD, 35 DEG F

Subgroup (13b)
 1  ! SRCNAM = BASE35   !
```

```
1 ! X =  543.10,  2992.90, 36.6,  0.00, 5.79, 22.43, 420.4, 1.0, 51.96, 3.26, 48.08, 0.0, 0.0, 19.05, 34.32 ! !
2 ! SRCNAM = COOLTOW !
2 ! X =  543.10,  2992.90, 13.7,  0.00,11.58,  6.21, 313.2, 1.0, 0.0, 0.0, 0.0, 0.0, 0.0, 0.586, 0.0 !  !END!

-------

   a
   Data for each source are treated as a separate input subgroup
   and therefore must end with an input group terminator.

   b
   0. = No building downwash modeled, 1. = downwash modeled
   NOTE: must be entered as a REAL number (i.e., with decimal point)

   c
   An emission rate must be entered for every pollutant modeled.
   Enter emission rate of zero for secondary pollutants that are
   modeled, but not emitted. Units are specified by IPTU
   (e.g. 1 for g/s).

---------------
Subgroup (13c)
---------------
       BUILDING DIMENSION DATA FOR SOURCES SUBJECT TO DOWNWASH
       -----------------------------------------------------

Subgroup (13c)
    1 ! SRCNAM = BASE35  !
    1 ! HEIGHT = 25.30, 25.30, 25.30, 25.30, 25.30, 25.30,
          25.30, 25.30, 25.30, 25.30, 25.30, 25.30,
          25.30, 25.30, 25.30, 25.30, 25.30, 25.30,
          25.30, 25.30, 25.30, 25.30, 25.30, 25.30,
          25.30, 25.30, 25.30, 25.30, 25.30, 25.30,
          25.30, 25.30, 25.30, 25.30, 25.30, 25.30 !
    1 ! WIDTH =  13.25, 16.64, 19.53, 21.83, 23.46, 24.38,
          24.56, 24.00, 22.70, 24.00, 24.57, 24.39,
          23.47, 21.83, 19.53, 16.64, 13.25,  9.45,
          13.25, 16.64, 19.53, 21.83, 23.46, 24.38,
          24.56, 24.00, 22.70, 24.00, 24.57, 24.39,
          23.47, 21.83, 19.53, 16.64, 13.25,  9.45 !

!END!
    2 ! SRCNAM = COOLTOW !
    2 ! HEIGHT = 12.19, 12.19, 12.19, 12.19, 12.19, 12.19,
          12.19, 12.19, 12.19, 12.19, 12.19, 12.19,
          12.19, 12.19, 12.19, 12.19, 12.19, 12.19,
          12.19, 12.19, 12.19, 12.19, 12.19, 12.19,
          12.19, 12.19, 12.19, 12.19, 12.19, 12.19,
          12.19, 12.19, 12.19, 12.19, 12.19, 12.19 !
    2 ! WIDTH = 151.52, 150.38, 144.66, 134.56, 120.36, 102.50,
          81.54, 58.09, 32.88, 58.09, 81.54, 102.50,
         120.36, 134.56, 144.66, 150.38, 151.52, 148.06,
         151.52, 150.38, 144.66, 134.56, 120.36, 102.50,
          81.54, 58.09, 32.88, 58.09, 81.54, 102.50,
         120.36, 134.56, 144.66, 150.38, 151.52, 148.06 !

!END!
```

Source a
No. Effective building width and height (in meters) every 10 degrees
----- --

----

a
Each pair of width and height values is treated as a separate input subgroup and therefore must end with an input group terminator.

Subgroup (13d)
----

a
POINT SOURCE: VARIABLE EMISSIONS DATA

Use this subgroup to describe temporal variations in the emission rates given in 13b. Factors entered multiply the rates in 13b. Skip sources here that have constant emissions. For more elaborate variation in source parameters, use PTEMARB.DAT and NPT2 > 0.

IVARY determines the type of variation, and is source-specific:
(IVARY) Default: 0
- 0 = Constant
- 1 = Diurnal cycle (24 scaling factors: hours 1-24)
- 2 = Monthly cycle (12 scaling factors: months 1-12)
- 3 = Hour & Season (4 groups of 24 hourly scaling factors, where first group is DEC-JAN-FEB)
- 4 = Speed & Stab. (6 groups of 6 scaling factors, where first group is Stability Class A, and the speed classes have upper bounds (m/s) defined in Group 12
- 5 = Temperature (12 scaling factors, where temperature classes have upper bounds (C) of: 0, 5, 10, 15, 20, 25, 30, 35, 40, 45, 50, 50+)

----
a
Data for each species are treated as a separate input subgroup and therefore must end with an input group terminator.

INPUT GROUPS: 14a, 14b, 14c, 14d -- Area source parameters

Subgroup (14a)

Number of polygon area sources with

```
    parameters specified below (NAR1)      No default  !  NAR1 =  0   !

    Units used for area source
    emissions below          (IARU)      Default: 1  !  IARU =   1  !
        1 =      g/m**2/s
        2 =      kg/m**2/hr
        3 =      lb/m**2/hr
        4 =    tons/m**2/yr
        5 =    Odour Unit * m/s  (vol. flux/m**2 of odour compound)
        6 =    Odour Unit * m/min
        7 =    metric tons/m**2/yr

    Number of source-species
    combinations with variable
    emissions scaling factors
    provided below in (14d)      (NSAR1) Default: 0  !  NSAR1 =  0  !

    Number of buoyant polygon area sources
    with variable location and emission
    parameters (NAR2)                    No default  !  NAR2 =  0   !
    (If NAR2 > 0, ALL parameter data for
    these sources are read from the file: BAEMARB.DAT)

!END!

---------------
Subgroup (14b)
---------------
                                 a
        AREA SOURCE: CONSTANT DATA
        ----------------------------
                                                   b
Source        Effect.   Base      Initial    Emission
 No.          Height  Elevation  Sigma z      Rates
               (m)      (m)        (m)
-------       ------   ------    --------   ---------


--------
   a
    Data for each source are treated as a separate input subgroup
    and therefore must end with an input group terminator.
   b
    An emission rate must be entered for every pollutant modeled.
    Enter emission rate of zero for secondary pollutants that are
    modeled, but not emitted.  Units are specified by IARU
    (e.g. 1 for g/m**2/s).

---------------
Subgroup (14c)
---------------

        COORDINATES (UTM-km) FOR EACH VERTEX(4) OF EACH POLYGON
        --------------------------------------------------------
Source                                                 a
 No.      Ordered list of X followed by list of Y, grouped by source
------    ------------------------------------------------------------
```

----
a
Data for each source are treated as a separate input subgroup
and therefore must end with an input group terminator.

Subgroup (14d)
----

a
AREA SOURCE: VARIABLE EMISSIONS DATA

Use this subgroup to describe temporal variations in the emission
rates given in 14b. Factors entered multiply the rates in 14b.
Skip sources here that have constant emissions. For more elaborate
variation in source parameters, use BAEMARB.DAT and NAR2 > 0.

IVARY determines the type of variation, and is source-specific:
(IVARY) Default: 0
0 = Constant
1 = Diurnal cycle (24 scaling factors: hours 1-24)
2 = Monthly cycle (12 scaling factors: months 1-12)
3 = Hour & Season (4 groups of 24 hourly scaling factors,
where first group is DEC-JAN-FEB)
4 = Speed & Stab. (6 groups of 6 scaling factors, where
first group is Stability Class A,
and the speed classes have upper
bounds (m/s) defined in Group 12
5 = Temperature (12 scaling factors, where temperature
classes have upper bounds (C) of:
0, 5, 10, 15, 20, 25, 30, 35, 40,
45, 50, 50+)

----
a
Data for each species are treated as a separate input subgroup
and therefore must end with an input group terminator.

INPUT GROUPS: 15a, 15b, 15c -- Line source parameters

Subgroup (15a)

Number of buoyant line sources
with variable location and emission
parameters (NLN2) No default ! NLN2 = 0 !

(If NLN2 > 0, ALL parameter data for
these sources are read from the file: LNEMARB.DAT)

```
   Number of buoyant line sources (NLINES)       No default   ! NLINES =  0  !

   Units used for line source
   emissions below              (ILNU)        Default: 1  !  ILNU =   1  !
       1 =       g/s
       2 =      kg/hr
       3 =      lb/hr
       4 =    tons/yr
       5 =    Odour Unit * m**3/s  (vol. flux of odour compound)
       6 =    Odour Unit * m**3/min
       7 =    metric tons/yr

   Number of source-species
   combinations with variable
   emissions scaling factors
   provided below in (15c)       (NSLN1) Default: 0  !  NSLN1 =  0  !

   Maximum number of segments used to model
   each line (MXNSEG)                        Default: 7   ! MXNSEG =  7  !

   The following variables are required only if NLINES > 0.  They are
   used in the buoyant line source plume rise calculations.

     Number of distances at which             Default: 6   ! NLRISE =  6  !
     transitional rise is computed

     Average building length (XL)            No default   ! XL = 0. !
                                      (in meters)

     Average building height (HBL)           No default   ! HBL = 0. !
                                      (in meters)

     Average building width (WBL)            No default   ! WBL = 0. !
                                      (in meters)

     Average line source width (WML)          No default   ! WML = 0. !
                                      (in meters)

     Average separation between buildings (DXL)  No default   ! DXL = 0. !
                                      (in meters)

     Average buoyancy parameter (FPRIMEL)       No default   ! FPRIMEL = 0. !
                                      (in m**4/s**3)

!END!

---------------
Subgroup (15b)
---------------

       BUOYANT LINE SOURCE: CONSTANT DATA
       ----------------------------------
                                                                     a
Source    Beg. X    Beg. Y     End. X    End. Y    Release   Base       Emission
 No.    Coordinate  Coordinate  Coordinate Coordinate  Height   Elevation     Rates
          (km)       (km)        (km)       (km)      (m)       (m)
------   ---------  ---------  ---------  ---------  ------   --------   ---------
```

----

a
Data for each source are treated as a separate input subgroup
and therefore must end with an input group terminator.

b
An emission rate must be entered for every pollutant modeled.
Enter emission rate of zero for secondary pollutants that are
modeled, but not emitted. Units are specified by ILNTU
(e.g. 1 for g/s).

Subgroup (15c)
----

a
BUOYANT LINE SOURCE: VARIABLE EMISSIONS DATA

Use this subgroup to describe temporal variations in the emission
rates given in 15b. Factors entered multiply the rates in 15b.
Skip sources here that have constant emissions.

IVARY determines the type of variation, and is source-specific:
(IVARY) Default: 0
0 = Constant
1 = Diurnal cycle (24 scaling factors: hours 1-24)
2 = Monthly cycle (12 scaling factors: months 1-12)
3 = Hour & Season (4 groups of 24 hourly scaling factors,
where first group is DEC-JAN-FEB)
4 = Speed & Stab. (6 groups of 6 scaling factors, where
first group is Stability Class A,
and the speed classes have upper
bounds (m/s) defined in Group 12
5 = Temperature (12 scaling factors, where temperature
classes have upper bounds (C) of:
0, 5, 10, 15, 20, 25, 30, 35, 40,
45, 50, 50+)

----
a
Data for each species are treated as a separate input subgroup
and therefore must end with an input group terminator.

INPUT GROUPS: 16a, 16b, 16c -- Volume source parameters

Subgroup (16a)

```
    Number of volume sources with
    parameters provided in 16b,c (NVL1)    No default  !  NVL1 =  0  !

    Units used for volume source
    emissions below in 16b      (IVLU)    Default: 1  !  IVLU =   1  !
         1 =       g/s
         2 =      kg/hr
         3 =      lb/hr
         4 =    tons/yr
         5 =    Odour Unit * m**3/s  (vol. flux of odour compound)
         6 =    Odour Unit * m**3/min
         7 =    metric tons/yr

    Number of source-species
    combinations with variable
    emissions scaling factors
    provided below in (16c)      (NSVL1)    Default: 0  !  NSVL1 =  0  !

    Gridded volume source data
    used ? (IGRDVL)                  No default  ! IGRDVL =  0   !
       0 = no
       1 = yes (gridded volume source
          emissions read from the file:
          VOLEM.DAT)

    The following parameters apply to the data in the
    gridded volume source emissions file (VOLEM.DAT)

     - Effective height of emissions
       (VEFFHT) in meters              No default  ! VEFFHT =  0. !

     - Initial sigma y (VSIGYI) in
       meters                       No default  ! VSIGYI =  0. !

     - Initial sigma z (VSIGZI) in
       meters                       No default  ! VSIGZI =  0. !

!END!

---------------
Subgroup (16b)
---------------
                                 a
         VOLUME SOURCE: CONSTANT DATA
         ------------------------------
                                                        b

    X UTM     Y UTM     Effect.   Base     Initial    Initial    Emission
  Coordinate Coordinate  Height  Elevation  Sigma y    Sigma z     Rates
    (km)      (km)       (m)      (m)        (m)       (m)
  ---------- ----------  ------   ------   --------  --------   --------

--------
  a
   Data for each source are treated as a separate input subgroup
   and therefore must end with an input group terminator.

  b
```

An emission rate must be entered for every pollutant modeled.
Enter emission rate of zero for secondary pollutants that are
modeled, but not emitted. Units are specified by IVLU
(e.g. 1 for g/s).

Subgroup (16c)
----

a
VOLUME SOURCE: VARIABLE EMISSIONS DATA

Use this subgroup to describe temporal variations in the emission
rates given in 16b. Factors entered multiply the rates in 16b.
Skip sources here that have constant emissions. For more elaborate
variation in source parameters, use VOLEM.DAT and IGRDVL = 1.

IVARY determines the type of variation, and is source-specific:
(IVARY) Default: 0
- 0 = Constant
- 1 = Diurnal cycle (24 scaling factors: hours 1-24)
- 2 = Monthly cycle (12 scaling factors: months 1-12)
- 3 = Hour & Season (4 groups of 24 hourly scaling factors, where first group is DEC-JAN-FEB)
- 4 = Speed & Stab. (6 groups of 6 scaling factors, where first group is Stability Class A, and the speed classes have upper bounds (m/s) defined in Group 12
- 5 = Temperature (12 scaling factors, where temperature classes have upper bounds (C) of: 0, 5, 10, 15, 20, 25, 30, 35, 40, 45, 50, 50+)

----
a
Data for each species are treated as a separate input subgroup
and therefore must end with an input group terminator.

INPUT GROUPS: 17a & 17b -- Non-gridded (discrete) receptor information
----

Subgroup (17a)

Number of non-gridded receptors (NREC) No default ! NREC = 126 !

!END!

Subgroup (17b)
----

a

NON-GRIDDED (DISCRETE) RECEPTOR DATA

Receptor No.		X UTM Coordinate (km)	Y UTM Coordinate (km)	Ground Elevation (m)	Height b Above Ground (m)	
1	! X =	557.0,	2789.0,	0.000,	0.000!	!END!
2	! X =	556.6,	2792.0,	0.000,	0.000!	!END!
3	! X =	556.0,	2796.0,	0.000,	0.000!	!END!
4	! X =	553.0,	2796.5,	0.000,	0.000!	!END!
5	! X =	548.0,	2796.5,	0.000,	0.000!	!END!
6	! X =	542.7,	2796.5,	0.000,	0.000!	!END!
7	! X =	542.7,	2800.0,	0.000,	0.000!	!END!
8	! X =	542.7,	2805.0,	0.000,	0.000!	!END!
9	! X =	542.7,	2810.0,	0.000,	0.000!	!END!
10	! X =	542.0,	2811.0,	0.000,	0.000!	!END!
11	! X =	541.3,	2814.0,	0.000,	0.000!	!END!
12	! X =	542.7,	2816.0,	0.000,	0.000!	!END!
13	! X =	544.1,	2820.0,	0.000,	0.000!	!END!
14	! X =	543.5,	2824.6,	0.000,	0.000!	!END!
15	! X =	545.0,	2829.0,	0.000,	0.000!	!END!
16	! X =	545.7,	2832.2,	0.000,	0.000!	!END!
17	! X =	546.2,	2835.7,	0.000,	0.000!	!END!
18	! X =	548.6,	2837.5,	0.000,	0.000!	!END!
19	! X =	550.3,	2839.0,	0.000,	0.000!	!END!
20	! X =	545.0,	2839.0,	0.000,	0.000!	!END!
21	! X =	540.0,	2839.0,	0.000,	0.000!	!END!
22	! X =	550.5,	2844.0,	0.000,	0.000!	!END!
23	! X =	545.0,	2844.0,	0.000,	0.000!	!END!
24	! X =	540.0,	2844.0,	0.000,	0.000!	!END!
25	! X =	550.3,	2848.6,	0.000,	0.000!	!END!
26	! X =	549.0,	2848.6,	0.000,	0.000!	!END!
27	! X =	548.0,	2848.6,	0.000,	0.000!	!END!
28	! X =	547.0,	2848.6,	0.000,	0.000!	!END!
29	! X =	546.0,	2848.6,	0.000,	0.000!	!END!
30	! X =	545.0,	2848.6,	0.000,	0.000!	!END!
31	! X =	544.0,	2848.6,	0.000,	0.000!	!END!
32	! X =	543.0,	2848.6,	0.000,	0.000!	!END!
33	! X =	542.0,	2848.6,	0.000,	0.000!	!END!
34	! X =	541.0,	2848.6,	0.000,	0.000!	!END!
35	! X =	540.0,	2848.6,	0.000,	0.000!	!END!
36	! X =	539.0,	2848.6,	0.000,	0.000!	!END!
37	! X =	538.0,	2848.6,	0.000,	0.000!	!END!
38	! X =	537.0,	2848.6,	0.000,	0.000!	!END!
39	! X =	536.0,	2848.6,	0.000,	0.000!	!END!
40	! X =	535.0,	2848.6,	0.000,	0.000!	!END!
41	! X =	534.0,	2848.6,	0.000,	0.000!	!END!
42	! X =	533.0,	2848.6,	0.000,	0.000!	!END!
43	! X =	532.0,	2848.6,	0.000,	0.000!	!END!
44	! X =	531.0,	2848.6,	0.000,	0.000!	!END!
45	! X =	530.0,	2848.6,	0.000,	0.000!	!END!
46	! X =	529.0,	2848.6,	0.000,	0.000!	!END!
47	! X =	528.0,	2848.6,	0.000,	0.000!	!END!
48	! X =	527.0,	2848.6,	0.000,	0.000!	!END!
49	! X =	526.0,	2848.6,	0.000,	0.000!	!END!
50	! X =	525.0,	2848.6,	0.000,	0.000!	!END!
51	! X =	524.0,	2848.6,	0.000,	0.000!	!END!

```
 52 ! X =    523.0,   2848.6,    0.000,    0.000!  !END!
 53 ! X =    522.0,   2848.6,    0.000,    0.000!  !END!
 54 ! X =    521.0,   2848.6,    0.000,    0.000!  !END!
 55 ! X =    520.0,   2848.6,    0.000,    0.000!  !END!
 56 ! X =    519.0,   2848.6,    0.000,    0.000!  !END!
 57 ! X =    518.0,   2848.6,    0.000,    0.000!  !END!
 58 ! X =    517.0,   2848.6,    0.000,    0.000!  !END!
 59 ! X =    516.0,   2848.6,    0.000,    0.000!  !END!
 60 ! X =    515.0,   2848.6,    0.000,    0.000!  !END!
 61 ! X =    514.5,   2848.6,    0.000,    0.000!  !END!
 62 ! X =    514.5,   2848.0,    0.000,    0.000!  !END!
 63 ! X =    514.5,   2847.6,    0.000,    0.000!  !END!
 64 ! X =    514.5,   2846.6,    0.000,    0.000!  !END!
 65 ! X =    514.5,   2845.0,    0.000,    0.000!  !END!
 66 ! X =    514.5,   2844.0,    0.000,    0.000!  !END!
 67 ! X =    514.5,   2843.0,    0.000,    0.000!  !END!
 68 ! X =    514.5,   2842.0,    0.000,    0.000!  !END!
 69 ! X =    514.5,   2841.0,    0.000,    0.000!  !END!
 70 ! X =    514.5,   2840.0,    0.000,    0.000!  !END!
 71 ! X =    514.5,   2839.0,    0.000,    0.000!  !END!
 72 ! X =    514.5,   2838.0,    0.000,    0.000!  !END!
 73 ! X =    514.5,   2837.0,    0.000,    0.000!  !END!
 74 ! X =    514.5,   2836.0,    0.000,    0.000!  !END!
 75 ! X =    514.5,   2835.0,    0.000,    0.000!  !END!
 76 ! X =    514.5,   2834.0,    0.000,    0.000!  !END!
 77 ! X =    514.5,   2833.0,    0.000,    0.000!  !END!
 78 ! X =    514.5,   2832.5,    0.000,    0.000!  !END!
 79 ! X =    510.0,   2832.5,    0.000,    0.000!  !END!
 80 ! X =    509.0,   2832.5,    0.000,    0.000!  !END!
 81 ! X =    508.0,   2832.5,    0.000,    0.000!  !END!
 82 ! X =    507.0,   2832.5,    0.000,    0.000!  !END!
 83 ! X =    506.0,   2832.5,    0.000,    0.000!  !END!
 84 ! X =    505.0,   2832.5,    0.000,    0.000!  !END!
 85 ! X =    504.0,   2832.5,    0.000,    0.000!  !END!
 86 ! X =    503.0,   2832.5,    0.000,    0.000!  !END!
 87 ! X =    502.0,   2832.5,    0.000,    0.000!  !END!
 88 ! X =    501.0,   2832.5,    0.000,    0.000!  !END!
 89 ! X =    500.0,   2832.5,    0.000,    0.000!  !END!
 90 ! X =    499.0,   2832.5,    0.000,    0.000!  !END!
 91 ! X =    498.0,   2832.5,    0.000,    0.000!  !END!
 92 ! X =    497.0,   2832.5,    0.000,    0.000!  !END!
 93 ! X =    496.0,   2832.5,    0.000,    0.000!  !END!
 94 ! X =    495.0,   2832.5,    0.000,    0.000!  !END!
 95 ! X =    495.0,   2833.0,    0.000,    0.000!  !END!
 96 ! X =    495.0,   2834.0,    0.000,    0.000!  !END!
 97 ! X =    495.0,   2835.0,    0.000,    0.000!  !END!
 98 ! X =    495.0,   2836.0,    0.000,    0.000!  !END!
 99 ! X =    494.5,   2837.0,    0.000,    0.000!  !END!
100 ! X =    491.5,   2841.0,    0.000,    0.000!  !END!
101 ! X =    488.5,   2845.5,    0.000,    0.000!  !END!
102 ! X =    483.0,   2848.5,    0.000,    0.000!  !END!
103 ! X =    480.0,   2852.5,    0.000,    0.000!  !END!
104 ! X =    475.0,   2854.0,    0.000,    0.000!  !END!
105 ! X =    473.5,   2857.0,    0.000,    0.000!  !END!
106 ! X =    473.0,   2860.0,    0.000,    0.000!  !END!
107 ! X =    472.0,   2860.0,    0.000,    0.000!  !END!
108 ! X =    471.0,   2860.0,    0.000,    0.000!  !END!
109 ! X =    470.0,   2860.0,    0.000,    0.000!  !END!
```

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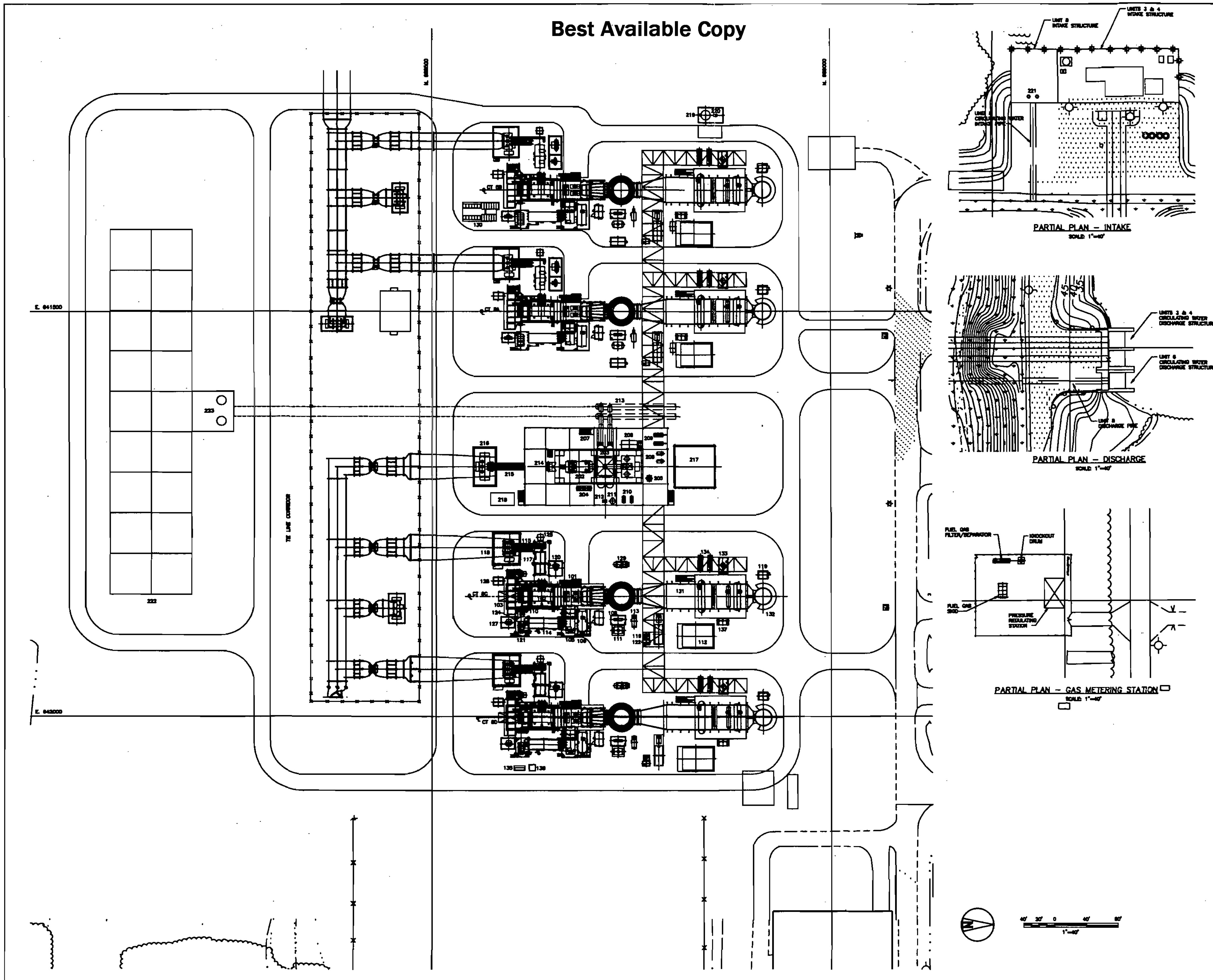
110 ! X =     469.0,   2860.0,    0.000,    0.000!  !END!
111 ! X =     468.0,   2860.0,    0.000,    0.000!  !END!
112 ! X =     467.0,   2860.0,    0.000,    0.000!  !END!
113 ! X =     466.0,   2860.0,    0.000,    0.000!  !END!
114 ! X =     465.0,   2860.0,    0.000,    0.000!  !END!
115 ! X =     464.0,   2860.0,    0.000,    0.000!  !END!
116 ! X =     463.0,   2860.0,    0.000,    0.000!  !END!
117 ! X =     462.0,   2860.0,    0.000,    0.000!  !END!
118 ! X =     461.0,   2860.0,    0.000,    0.000!  !END!
119 ! X =     460.0,   2860.0,    0.000,    0.000!  !END!
120 ! X =     459.5,   2863.2,    0.000,    0.000!  !END!
121 ! X =     459.0,   2863.2,    0.000,    0.000!  !END!
122 ! X =     458.0,   2863.2,    0.000,    0.000!  !END!
123 ! X =     457.0,   2863.2,    0.000,    0.000!  !END!
124 ! X =     456.0,   2863.2,    0.000,    0.000!  !END!
125 ! X =     455.0,   2863.2,    0.000,    0.000!  !END!
126 ! X =     454.0,   2863.2,    0.000,    0.000!  !END!
```

....

a
Data for each receptor are treated as a separate input subgroup and therefore must end with an input group terminator.

b
Receptor height above ground is optional. If no value is entered, the receptor is placed on the ground.

0137609/4 MARTIN/4.2/4.2.2 PSD/2-2.DWG (1/26/02)



EQUIPMENT IDENTIFICATION LIST	
REF. No.	EQUIPMENT NAME
101	CTGC COMBUSTION TURBINE
102	CTGC GENERATOR
103	CTGC INLET AIR FILTER
104	CTGC EXHAUST STACK
105	CTGC ACCESSORY MODULE
106	CTGC LIQUID FUEL / ATOMIZING AIR MODULE
107	CTGC WATER INJECTION SKID
108	CTGC DRAINS TANK
109	CTGC STARTUP AIR COMPRESSOR
110	CTGC AIR DRYER
111	CTGC WATER WASH DRAINS TANK (BURIED)
112	CTGC COOLING WATER MODULE
113	CTGC FIRE PROTECTION / CO2 SKID
114	CTGC PEECC
115	CTGC ISOLATED PHASE BUS DUCT
116	CTGC FUEL GAS SCRUBBER DRAINS TANK
117	CTGC LCI / EX2000
118	CTGC MAIN STEP-UP TRANSFORMER
119	CTGC CONTINUOUS EMISSION MONITORING EQUIP.
120	CTGC EXCITATION TRANSFORMER
121	CTGC MCC
122	CTGC FUEL GAS SCRUBBER
123	CTGC LCI ISOLATION TRANSFORMER
124	CTGC 480V SECONDARY UNIT SUBSTATION
125	CTGC DC LINK REACTOR
126	CTGC FUEL GAS HEATER (DIRECT FIRED)
127	CTGC 480V BUS TRANSFORMER
128	CTGC FOGGER SKID
129	CTGC OIL WATER SEPARATOR
130	CTGC 4160V SWITCHGEAR
131	CTGC HEAT RECOVERY STEAM GENERATOR
132	CTGC HRSG EXHAUST STACK
133	CTGC HRSG BLOW DOWN TANK
134	CTGC BOILER FEED PUMPS
135	CONSTRUCTION SWITCHBOARD
136	CONSTRUCTION TRANSFORMER
137	CTGC AMMONIA SKID ASSEMBLY
201	STEAM TURBINE
202	STEAM TURBINE GENERATOR
203	STEAM TURBINE CONDENSER
204	CONDENSATE PUMP
205	EHC UNIT
206	STEAM TURBINE LUBE OIL STORAGE TANK
207	STEAM TURBINE GENERATOR SEAL OIL UNIT
208	CLOSED CYCLE COOLING WATER PUMP
209	CLOSED CYCLE COOLING WATER HEAT EXCHANGER
210	AIR COMPRESSORS
211	AIR RECEIVER
212	AIR DRYER
213	CIRCULATING WATER PIPING
214	STEAM TURBINE EXCITATION COMPARTMENT
215	ISOLATED PHASE BUS DUCT
216	STEAM TURBINE MAIN STEP-UP TRANSFORMER
217	AUXILIARY CONDENSER
218	4160V SWITCHGEAR
219	AMMONIA STORAGE TANK
220	AMMONIA FORWARDING PUMPS
221	CIRCULATING WATER PUMPS
222	OPTIONAL COOLING TOWER
223	CIRCULATING WATER PUMPS

NOTES:

1. THE EQUIPMENT ARRANGEMENT SHOWN IS TYPICAL OF A COMBINED CYCLE FACILITY.

Figure 2-2. Overall Site Arrangement

Source: Black & Veatch, 2001; FPL, 2001; and Golder, 2001.

FPL

Martin Unit 8

Table B-2. Summary of BACT Determinations for NO_x for Combined Cycle CTs, 1999-2001

Facility	State	Final Permit Issued	MW	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NOx Limit	Control Method	Avg. Time	Comments
Alabama Power, Plant Barry	AL	Aug-99	200	1	1	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm / 0.013 lb/MMBtu	DLN/SCR		
Mobile Energy, LLC - Hog Bayou	AL	Jan-99	200	1	1	GE 7FA (168 MW)	NG; FO	CC	8,760; 675 FO	3.5 ppm NG; 41 ppm w/ FO	DLN/SCR;WI		
Alabama Power - Theodore Cogeneration Facility	AL	Mar-99	210	1	1	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm/ 0.013 lb/MMBtu	DLN/SCR		
Tenaska Alabama Partners	AL	Nov-99	846	3	3	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	3.95 ppm NG; 11.3 ppm FO	DLN/SCR; WI/SCR		
Georgia Power - Goat Rock	AL	Apr-00	-	8	8	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm/ 0.013 lb/MMBtu	DLN/SCR		
Georgia Power - Goat Rock (revision of above PSD application)	AL	Apr-01	2,460	8	8	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm/ 0.013 lb/MMBtu	DLN/SCR		
Alabama Electric Cooperative - Gantt Plant	AL	Mar-00	500	2	2	SW 501F (166 MW)	NG	CC	8,760	3.5 ppm / 0.013 lb/MMBtu	DLN/SCR		
South Eastern Energy Corp.	AL	Jan-01	1,500	6	6 if CC	GE 7FA or SW 501F	NG	SC or CC	8,760	9 or 25 or 3.5 ppm	DLN if SC/SCR if CC		For NO_x and CO: SC w/GE or SC w/SW501F or CC (either)
Calpine Solutia - Decatur	AL	Jun-00	700	3	3	SW501F (180 MW)	NG	CC	8,760	3.5 ppm/ 0.013 lb/MMBtu	SCR		
Calpine BP Amoco	AL	Jun-00	700	3	3	SW501F (180 MW)	NG	CC	8,760	3.5 ppm/ 0.013 lb/MMBtu	SCR		
Tenaska Alabama II Generating Station	AL	Feb-01	900	3	3	GE 7FA or Mitsubishi M501F	NG; FO	CC	8,760; 720 FO	0.013/0.048 lb/mmbtu NG/FO - GE; 0.013/0.046 lb/mmbtu	SCR/WI		
Hillabee Energy Center	AL	Jan-01	700	2	2	SW501G (229 MW)	NG	CC	8,760	3.5 ppm	DLN/SCR		PA = Power Augmentation, DB= Duct Burning
Duke Energy - Alexander City	AL	Feb-01	1,260	10	2	GE 7FA & 7EA	NG	CC & SC	8,760 CC; 2,500 SC	3.5 ppm (0.013 lb/mmBtu) CC; 9/12 ppm (0.033 lb/mmBtu)	SCR - CC, DLN-SC	an/1-hr	8 SC units and 2 CC units
GenPower - Kelly, LLC	AL	Jan-01	1,260	4	4	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	SCR		
Blount County Energy	AL	Jan-01	800	3	3	"F" Class (170 MW)	NG	CC	8,760	0.013 lb/mmBtu (30.7 lb/hr)	SCR	3-hr	
Alabama Power - Autaugaville	AL	Jan-01	1,260	4	4	"F" Class (170 MW)	NG	CC	8,760	3.5 ppm (0.013 lb/mmBtu)	SCR		
Tenaska Alabama IV Partners	AL	draft permit	1,840	6	6	Mit 501F (170 MW)	NG; FO	CC	8,760; 720 FO	3.5 ppm NG; 12 ppm FO	SCR		SCONOx - \$6,145/ton NO_x; CatOx- \$1,506/ton CO
Duke Energy Autauga, LLC	AL	applic. under review	630	2	2	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	SCR		SCONOx - \$18760/ton NO_x; CatOx- \$5,006/ton CO
Kissimmee Utility Authority, Cane Island Power Park -Unit 3	FL	draft permit	250	1	0	GE 7FA (167 MW)	NG; FO	CC	8,760; 720 FO	3.5 ppm NG; 15 ppm FO	SCR		
Duke Energy - New Smyrna Beach	FL	draft permit	500	2	0	GE 7FA (165 MW)	NG	CC	8,760	9 ppm or 6 ppm	DLN or SCR		
Lake Worth Generation	FL	Nov-99	244	1	1	GE 7FA (170 MW)	NG; FO	CC	8,760; 1,000 FO	9 ppm NG; 42 ppm FO	DLN; WI		
Hines Energy (FPC)	FL	project dropped	500	2	0	SW 501F (165 MW)	NG; FO	CC	8,760; 1,000 FO	6 ppm NG - full load; 42 ppm FO	SCR; WI		
Gulf Power - Smith Station	FL	Jul-00	340	2	2	GE 7FA (170 MW)	NG	CC	8,760	82.9 lb/hr w/DB, 113.2 lb/hr w/ DB & SA	DLN	30-day	Netting out of PSD for NO_x and CO; SA = steam augmentation
Florida Power & Light - Sanford	FL	Sep-99	2,200	8	0	GE 7FA (170 MW)	NG, FO	CC	8,760; 500 FO	9 ppm NG; 42 ppm FO	DLN; WI		Repowering, 4 units FO
Gainesville Regional Utilities, Kelly Generating Station	FL	Feb-00	133	1	0	GE 7EA (83 MW)	NG; FO	CC	8,760; 1,000 FO	9 ppm NG; 42 ppm FO	DLN; WI		Netting out of PSD review for NO_x
Calpine Osprey Energy Center	FL	Jul-01	527	2	2	SW 501FD (170 MW)	NG	CC	8,760	3.5 ppm	DLN/SCR	24-hr Block	2,800 hr/yr - Power Aug. mode

Table B-2. Summary of BACT Determinations for NO_x for Combined Cycle CTs, 1999-2001

Facility	State	Final Permit Issued	MW	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NOx Limit	Control Method	Avg. Time	Comments
Hines Energy (FPC)	FL	Jun-01	530	2	0	SW 501FD (170 MW)	NG; FO	CC	8,760; 1,000 FO	3.5 ppm NG; 12 ppm FO	SCR; WI	24-hr Block	SCONOx - $16,712/ton NO_x.; CatOx - $2,130/ton CO
CPV - Gulfcoast	FL	Feb-01	250	1	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	3.5 ppm NG; 10 ppm FO	SCR		SCONOx - no cost eval.; CatOx - $4,350/ton CO
TECO Gannon/Bayside	FL	Mar-01	1,728	7	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 876 FO	3.5 ppm NG; 16.4 ppm FO	SCR		Repowering project: netting out of NO_x, CO, PM_{10} and SO_2 review (subject to VOC reveiw)
South Pond Energy Park	FL	draft permit	600	3	0	GE 7FA (170 MW)	NG; FO	SC/CC	3,390/8,760; 720 FO	10 ppm (9 initial)/3.5 ppm NG; 42/15 ppm FO	DLN/SCR; WI	3-hr	2 SC CT and 1 CC CT also capable of operating in SC mode.
North Pond Energy Park	FL	applic. under review	430	2	0	GE 7FA (170 MW)	NG; FO	SC/CC	3,390/8,760; 720 FO	10 ppm (9 initial)/3.5 ppm NG; 42/15 ppm FO	DLN/SCR; WI	3-hr	1 SC CT and 1 CC CT also capable of operating in SC mode.
Calpine Blue Heron Energy Center	FL	draft permit	1,080	4	4	SW 501F (170 MW)	NG	CC	8,760	3.5 ppm	DLN/SCR		base/duct burner/power aug./60-70% load; SCONOx - $9,982/ton NO_x; CatOx - $1,553/ton CO
Jacksonville Electric Authority - Brandy Branch (revision)	FL	draft permit	200	0	2	GE 7FA (170 MW)	NG; FO	CC	8760; 288 FO	3.5 ppm NG; 15 ppm FO	SCR		Conversion of 2 SC units to 2 CC units
CPV - Atlantic Power	FL	May-01	250	1	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	3.5 ppm NG; 10 ppm FO	SCR		PA = Power Augmentation
Orlando Utilities - Curtis H Stanton Energy Center	FL	Sep-01	633	2	2	GE 7FA (170 MW)	NG; FO	CC	8,760; 1000 FO	3.5 ppm NG; 10 ppm FO	SCR		
Broward Energy Center	FL	draft permit	775	4	0	GE 7FA (175 MW)	NG	CC/SC	8,760/5,000	3.5 ppm/9 ppm	SCR/DLN	24-hr	* 1 CC w/unfired HRSG & 3 SC; PA = Power Augmentation
Belle Glade Energy Center	FL	draft permit	600	3	0	GE 7FA (175 MW)	NG	CC/SC	8,760/5,000	3.5 ppm/9 ppm	SCR/DLN	24-hr	* 1 CC w/unfired HRSG & 2 SC; PA = Power Augmentation
Manatee Energy Center	FL	draft permit	600	3	0	GE 7FA (175 MW)	NG	CC/SC	8,760/5,000	3.5 ppm/9 ppm	SCR/DLN	24-hr	* 1 CC w/unfired HRSG & 2 SC; PA = Power Augmentation
CPV Pierce Power Generation Facility	FL	Aug-01	250	1	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	2.5 ppm NG; 10 ppm FO	SCR	24-hr	PA limited to 2,000 hr/yr
Fort Pierce Repowering Project	FL	draft permit	180	1	1	SW 501F (180 MW)	NG; FO	CC/SC	8,760; 1,000 FO/2,000; 500 FO	3.5 ppm NG; 12 ppm FO/25 ppm NG; 42 ppm FO	SCR/DLN; WI		CT will operate in both CC and SC modes
TECO Bayside Power Station	FL	draft permit	1,032	4	0	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	SCR		Repowering Project: Netting out of PSD for NO_x, SO_2, VOC, lead and SAM (subject for PM_{10} and CO)
Georgia Power - Wansley (Oglethorpe Power)	GA	Jul-00	2,280	8	8	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm / 0.013 lb/MMBtu	DLN/SCR	30 day	
Duke Energy Murray, LLC	GA	Feb-01	1,240	4	4	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	DLN/SCR		
Duke Energy Buffalo Creek, LLC	GA	applic. under review	620	2	2	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	DLN/SCR		SCONOx - $19,948/ton NO_x; CatOx - $2,469/ton CO
Augusta Energy LLC	GA	draft permit	750	3	3	GE 7FA (170 MW)	NG; FO	CC	8,760; 1,000 FO	3.5 ppm NG; 42 ppm FO	SCR; WI		SCONOx - $17,490/ton NO_x; CatOx - $4,133/ton CO
GenPower McIntosh	GA	applic. under review	528	2	2	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	SCR		
Monroe Power Co.	GA	applic. under review	525	2	0	GE 7FA (170 MW)	NG	SC/CC	8,760	12/3.5 ppm	DLN/SCR		Initially SC, but later converting to CC
Peace Valley Generation Co., LLC	GA	applic. under review	1,550	6	4	F" Class	NG	CC/SC	8,760/2,500	3.5/9 ppm	SCR/DLN;		
Duke Energy Tift	GA	applic. under review	620	2	2	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	SCR		SCONOx - $16,274/ton NO_x; CatOx - $2,095/ton CO
CPV Terrapin, LLC	GA	applic. under review	800	3	3	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	3.5 ppm NG; 5.4 ppm (NG w/DB); 8.0 ppm FO	SCR		

Table B-2. Summary of BACT Determinations for NO_x for Combined Cycle CTs, 1999-2001

Facility	State	Final Permit Issued	MW	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NOx Limit	Control Method	Avg. Time	Comments
Kinder Morgan Georgia, LLC - Tift Power	GA	applic. under review	560	7	7	1 - GE 7EA & 6 - LM6000	NG	CC	8,760; 3,760 (part load)	9 ppm & 22 ppm	DLN & WI	annual	
Hartwell Development Co.	GA	applic. under review	564	2	0	GE 7FA (176 MW)	NG	CC	8,760	3.5 ppm	SCR		SCONOx - $35,422/ton NO_x; CatOx - $4,964/ton CO
Kentucky Pioneer Energy	KY	Jun-01	540	2	0	GE 7FA (197 MW)	syngas/ NG	CC	8,760	15/20 ppm	Steam Injection	3-hr	
Duke Energy Hinds, L.L.C.	MS	Apr-00	520	2	0	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	DLN/SCR		
Duke Energy Attala, L.L.C.	MS	Apr-00	520	2	0	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	DLN/SCR		
Cogentrix Energy, Southaven Power Project	MS	draft permit	800	3	3	GE 7FA (170 MW)	NG	CC	8,760	4.5 ppm (10.8 ppm w/ DB)	DLN/SCR		
Cogentrix Energy, Caledonia Power Project	MS	Mar-01	800	3	3	GE 7FA (182 MW)	NG	CC	8,760	3.5 ppm (w/DB)	DLN/SCR		revised application to add SCR
GenPower - McAdams LLC	MS	draft permit	528	2	2	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	DLN/SCR	24-hr	
Lone Oak Energy Center	MS	draft permit	800	3	3	F" Class (180 MW)	NG	CC	8,760	3.5 ppm	SCR		Base/PA/PA+DF/DF
Lee Power Partners	MS	draft permit	1,000	4	4	F" Class (170 MW)	NG	CC	8,760	3.5 ppm	SCR		
LSP-Pike Energy LLC	MS	draft permit	1,100	4	4	F" Class (170 MW)	NG	CC	8,760	4.5 ppm	SCR		
Magnolia Energy	MS	draft permit	900	3	3	F" Class (170 MW)	NG	CC	8,760	3.5 ppm	SCR		
Hines Energy Facility	MS	Jan-00	340	2	?	170 MW each	NG	CC	8,760	3.5 ppm	DLN, SCR		
Reliant Energy - Choctaw Co., LLC	MS	draft permit	844	3	3	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	DLN, SCR	30-day	SCONOx - $48,663/ton NO_x; CatOx - $3,550/ton CO
Crossroads Energy Center	MS	applic. under review	580	2	2	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	SCR		SCONOx - $23,400/ton NO_x; CatOx - $11,039/ton CO
Choctaw Gas Generation, LLC	MS	applic. under review	700	2	2	SW 501G (250 MW)	NG	CC	8,760	3.5 ppm	SCR		
Duke Energy Homochitto, LLC	MS	applic. under review	630	2	2	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	SCR	24-hr	
Granite Power Partners II (Batesville)	MS	applic. under review	300	1	1	SW 501F (230 MW)	NG	CC	8,760	3.5 ppm	SCR		
Carolina Power & Light, Richmond Co. (2nd revision - new configuration)	NC	applic. under review	2,040	9	0	GE 7FA (170 MW)	NG; FO	CC/SC	8,760/2,000; 1,000 FO	3.5/9 ppm NG; 13/42 ppm FO	SCR/DLN; SCR/WI	24-hr	Reconfiguration of facility: 6 CC and 3 SC CTs
Carolina Power & Light, Rowan Co. (revision)	NC	draft permit	1,110	2	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 1,000 FO	9 ppm NG; 42 ppm FO	DLN; WI		Modification of previous permit to switch 2 SC -> CC
Butler-Warner Generation Plant	NC	applic. under review	500	2	0	GE 7FA (170 MW)	NG; FO	SC & CC	8,760; 500 FO	9 ppm NG; 42 ppm FO	DLN; WI		
GenPower Earleys, LLC	NC	applic. under review	528	2	2	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	SCR		SCONOx - $21,942/ton NO_x; CatOx - $3,246ton CO
Santee Cooper, Rainey Generating Station	SC	Apr-00	870	4	0	GE 7FA (170 MW)	NG, FO	2 CC, 2 SC	8,760; 1,000 FO	9 ppm NG; 42 ppm FO	DLN; WI		
SC Electric & Gas - Urquhart	SC	Sep-00	444	2	0	GE 7FA (150 MW)	NG, FO	CC	8,760; 4,380 FO	45 ppm	DLN		Netted out of NO_x, SO_2 and PM_{10} PSD Review
Columbia Energy	SC	Apr-01	515	2	2	GE 7FA (170 MW)	NG, FO	CC	8,760; 1,000 FO	3.5 ppm NG; 12 ppm FO	DLN/SCR; WI		SCONOx - no analysis; CatOx - $1,611/ton CO
GenPower Anderson	SC	draft permit	640	2	2	GE 7FA (170 MW)	NG	CC	8760	3.5 ppm	DLN/SCR		
Vanderbilt University	TN	May-00	10	2	2	GE PGT5B (5.2 MW)	NG	CC	8,760	25 ppm	DLN		

Table B-2. Summary of BACT Determinations for NO_x for Combined Cycle CTs, 1999-2001

Facility	State	Final Permit Issued	MW	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NOx Limit	Control Method	Avg. Time	Comments
Memphis Generation LLC	TN	draft permit	1,050	4	0	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	SCR		Phase I - 1 CT (up to 7% total plant heat input from refinery fuel gas), Phase II - 3 CTs (up to 2% total plant heat input from refinery fuel gas)
Haywood Energy Center (Calpine)	TN	applic. under review	900	3	3	SW, GE 7FA or GE F7B	NG; FO	CC	8,760	3.5 ppm NG; 42 ppm FO	DLN/SCR; WI		
TVA - Franklin	TN	applic. under review	610	2	2	GE 7FA (195 MW)		CC	8,760	3.5 ppm	SCR		

Abbreviations:
GE = General Electric
SW = Seimens Westinghouse
NG = Nat. Gas
FO = Fuel Oil
DB = Duct Burner
SC = Simple Cycle
CC = Combined Cycle
DLN = Dry-Low NO_x
WI = Water Injection
SCR = Selective Catalytic Reduction
CatOx = Catalytic Oxidation
GCP = Good Combustion Practices

Source: http://www.epa.gov/region4/air/permits/national_ct_list.xls (2001)

Table B-7. Summary of BACT Determinations for CO for Combined Cycle CTs, 1999-2001

Facility	State	Final Permit Issued	# of New MW	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	CO Limit	Control Method	Avg. Time	Comments
Alabama Power, Plant Barry	AL	Aug-99	200	1	1	GE 7FA (170 MW)	NG	CC	8,760	0.060 lb/MMBtu	GCP		
Mobile Energy, LLC - Hog Bayou	AL	Jan-99	200	1	1	GE 7FA (168 MW)	NG; FO	CC	8,760; 675 FO	0.040 lb/MMBtu NG; 0.058 lb/mmBtu FO	GCP		
Alabama Power - Theodore Cogeneration Facility	AL	Mar-99	210	1	1	GE 7FA (170 MW)	NG	CC	8,760	0.086 lb/MMBtu	GCP		
Tenaska Alabama Partners	AL	Nov-99	846	3	3	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	32.9 ppm NG; 46.7 ppm NG/FO	GCP		
Georgia Power - Goat Rock	AL	Apr-00	-	8	8	GE 7FA (170 MW)	NG	CC	8,760	0.086 lb/MMBtu	GCP		
Georgia Power - Goat Rock (revision of above PSD application)	AL	Apr-01	2,460	8	8	GE 7FA (170 MW)	NG	CC	8,760	0.086 lb/MMBtu	GCP		
Alabama Electric Cooperative - Gantt Plant	AL	Mar-00	500	2	2	SW 501F (166 MW)	NG	CC	8,760	0.057 lb/MMBtu	GCP		
South Eastern Energy Corp.	AL	Jan-01	1,500	6	6 if CC	GE 7FA or SW 501F	NG	SC or CC	8,760	9 or 19 or 22 ppm	GCP		For NO_x and CO: SC w/GE or SC w/SW501F or CC (either)
Calpine Solutia - Decatur	AL	Jun-00	700	3	3	SW501F (180 MW)	NG	CC	8,760	0.117 lb/mmBtu	GCP		
Calpine BP Amoco	AL	Jun-00	700	3	3	SW501F (180 MW)	NG	CC	8,760	0.117 lb/mmBtu	GCP		
Tenaska Alabama II Generating Station	AL	Feb-01	900	3	3	GE 7FA or Mitsubishi M501F	NG; FO	CC	8,760; 720 FO	0.037/0.047/0.089 lb/mmbtu (base/PA/FO) - GE; 0.088/0.116/0.35 lb/mmbtu (base/PA/FO) - Mit	GCP		
Hillabee Energy Center	AL	Jan-01	700	2	2	SW501G (229 MW)	NG	CC	8,760	0.023/0.076 lb/mmBtu (w/PA and/or DB)	GCP		PA = Power Augmentation, DB= Duct Burning
Duke Energy - Alexander City	AL	Feb-01	1,260	10	2	GE 7FA & 7EA	NG	CC & SC	8,760 CC; 2,500 SC	0.059 lb/mmBtu (130 lb/hr) CC; 0.09 lb/mmBtu (80 lb/hr) SC	GCP		8 SC units and 2 CC units
GenPower - Kelly, LLC	AL	Jan-01	1,260	4	4	GE 7FA (170 MW)	NG	CC	8,760	9 ppm, 14 ppm (w/DB)	GCP		
Blount County Energy	AL	Jan-01	800	3	3	"F" Class (170 MW)	NG	CC	8,760	0.033 lb/mmBtu (77.7 lb/hr)	GCP		
Alabama Power - Autaugaville	AL	Jan-01	1,260	4	4	"F" Class (170 MW)	NG	CC	8,760	0.035 lb/mmBtu	GCP		
Tenaska Alabama IV Partners	AL	draft permit	1,840	6	6	Mit 501F (170 MW)	NG; FO	CC	8,760; 720 FO	0.088 lb/mmBtu NG (0.115 w/PA & DB); 0.35 lb/mmBtu FO	GCP		SCONOx - $6,145/ton NO_x; CatOx- $1,506/ton CO
Duke Energy Autauga, LLC	AL	applic. under review	630	2	2	GE 7FA (170 MW)	NG	CC	8,760	15 ppm	GCP		SCONOx - $18760/ton NO_x; CatOx- $5,006/ton CO
Kissimmee Utility Authority, Cane Island Power Park -Unit 3	FL	draft permit	250	1	0	GE 7FA (167 MW)	NG; FO	CC	8,760; 720 FO	12 ppm, 20 ppm w/ DB NG; 30 ppm FO	GCP		
Duke Energy - New Smyrna Beach	FL	draft permit	500	2	0	GE 7FA (165 MW)	NG	CC	8,760	12 ppm	GCP		
Lake Worth Generation	FL	Nov-99	244	1	1	GE 7FA (170 MW)	NG; FO	CC	8,760; 1,000 FO	12 ppm NG; 20 ppm FO	GCP		
Hines Energy (FPC)	FL	project dropped	500	2	0	SW 501F (165 MW)	NG; FO	CC	8,760; 1,000 FO	25 ppm NG - full load; 30 ppm FO	GCP		
Gulf Power - Smith Station	FL	Jul-00	340	2	2	GE 7FA (170 MW)	NG	CC	8,760	16 ppm w/ DB, 23 ppm w/ DB & SA	GCP		Netting out of PSD for NO_x and CO; SA = steam augmentation
Florida Power & Light - Sanford	FL	Sep-99	2,200	8	0	GE 7FA (170 MW)	NG, FO	CC	8,760; 500 FO	12 ppm NG; 20 ppm FO	GCP		Repowering, 4 units FO
Gainesville Regional Utilities, Kelly Generating Station	FL	Feb-00	133	1	0	GE 7EA (83 MW)	NG; FO	CC	8,760; 1,000 FO	20 ppm NG; 20 ppm FO	GCP		Netting out of PSD review for NO_x
Calpine Osprey Energy Center	FL	Jul-01	527	2	2	SW 501FD (170 MW)	NG	CC	8,760	10 ppm (17 ppm w/DB or PA)	GCP	24-hr Block	2,800 hr/yr - Power Aug. mode
Hines Energy (FPC)	FL	Jun-01	530	2	0	SW 501FD (170 MW)	NG; FO	CC	8,760; 1,000 FO	16 ppm NG; 30 ppm FO	GCP	24-hr Block	SCONOx - $16,712/ton NO_x.; CatOx - $2,130/ton CO
CPV - Gulfcoast	FL	Feb-01	250	1	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	9 ppm NG; 20 ppm FO	GCP		SCONOx - no cost eval.; CatOx - $4,350/ton CO
TECO Gannon/Bayside	FL	Mar-01	1,728	7	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 876 FO	7.2 ppm NG; 14.2 ppm FO	GCP		Repowering project: netting out of NO_x, CO, PM_{10} and SO_2 review (subject to VOC reveiw)
South Pond Energy Park	FL	draft permit	600	3	0	GE 7FA (170 MW)	NG; FO	SC/CC	3,390/8,760; 720 FO	9 ppm NG; 20 ppm FO	GCP		2 SC CT and 1 CC CT also capable of operating in SC mode.

Table B-7. Summary of BACT Determinations for CO for Combined Cycle CTs, 1999-2001

Facility	State	Final Permit Issued	# of New MW	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	CO Limit	Control Method	Avg. Time	Comments
North Pond Energy Park	FL	applic. under review	430	2	0	GE 7FA (170 MW)	NG; FO	SC/CC	3,390/8,760; 720 FO	9 ppm NG; 20 ppm FO	GCP		1 SC CT and 1 CC CT also capable of operating in SC mode.
Calpine Blue Heron Energy Center	FL	draft permit	1,080	4	4	SW 501F (170 MW)	NG	CC	8,760	10/15.6/38.5/50 ppm	GCP		base/duct burner/power aug./60-70% load; SCONOx - $9,982/ton NO_x; CatOx - $1,553/ton CO
Jacksonville Electric Authority - Brandy Branch (revision)	FL	draft permit	200	0	2	GE 7FA (170 MW)	NG; FO	CC	8760; 288 FO	12.21/14.17 ppm	GCP		Conversion of 2 SC units to 2 CC units
CPV - Atlantic Power	FL	May-01	250	1	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	9 ppm NG (15 ppm w/PA) ; 20 ppm FO	GCP		PA = Power Augmentation
Orlando Utilities - Curtis H Stanton Energy Center	FL	Sep-01	633	2	2	GE 7FA (170 MW)	NG; FO	CC	8,760; 1000 FO	18.1 ppm NG (26.3 w/PA); 14.3 ppm FO	GCP		
Broward Energy Center	FL	draft permit	775	4	0	GE 7FA (175 MW)	NG	CC/SC	8,760/5,000	8 ppm (SC); 12 ppm (CC w/PA); 8 ppm (CC)	GCP	24-hr	* 1 CC w/unfired HRSG & 3 SC; PA = Power Augmentation
Belle Glade Energy Center	FL	draft permit	600	3	0	GE 7FA (175 MW)	NG	CC/SC	8,760/5,000	8 ppm (SC); 12 ppm (CC w/PA); 8 ppm (CC)	GCP	24-hr	* 1 CC w/unfired HRSG & 2 SC; PA = Power Augmentation
Manatee Energy Center	FL	draft permit	600	3	0	GE 7FA (175 MW)	NG	CC/SC	8,760/5,000	8 ppm (SC); 12 ppm (CC w/PA); 8 ppm (CC)	GCP	24-hr	* 1 CC w/unfired HRSG & 2 SC; PA = Power Augmentation
CPV Pierce Power Generation Facility	FL	Aug-01	250	1	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	8 ppm NG (13 ppm w/PA) ; 17 ppm FO (19 ppm 76-89% load, 26 ppm 50-75% load)	GCP	24-hr	PA limited to 2,000 hr/yr
Fort Pierce Repowering Project	FL	draft permit	180	1	1	SW 501F (180 MW)	NG; FO	CC/SC	8,760; 1,000 FO/2,000; 500 FO	3.5 ppm NG; 10 ppm FO/ 16 ppm NG; 50 ppm FO	GCP		CT will operate in both CC and SC modes
TECO Bayside Power Station	FL	draft permit	1,032	4	0	GE 7FA (170 MW)	NG	CC	8,760	9 ppm (7.8 ppm)	GCP	24-hr (3-hr test)	Repowering Project: Netting out of PSD for NO_x, SO_2, VOC, lead and SAM (subject for PM_{10} and CO)
Georgia Power - Wansley (Oglethorpe Power)	GA	Jul-00	2,280	8	8	GE 7FA (170 MW)	NG	CC	8,760	29.5 ppm/0.066 lb/MMBtu	GCP		
Duke Energy Murray, LLC	GA	Feb-01	1,240	4	4	GE 7FA (170 MW)	NG	CC	8,760	21.8 ppm	GCP		
Duke Energy Buffalo Creek, LLC	GA	applic. under review	620	2	2	GE 7FA (170 MW)	NG	CC	8,760	21.9 ppm	GCP		SCONOx - $19,948/ton NO_x; CatOx - $2,469/ton CO
Augusta Energy LLC	GA	draft permit	750	3	3	GE 7FA (170 MW)	NG; FO	CC	8,760; 1,000 FO	17.4 ppm NG; 20 ppm FO	GCP		SCONOx - $17,490/ton NO_x; CatOx - $4,133/ton CO
GenPower McIntosh	GA	applic. under review	528	2	2	GE 7FA (170 MW)	NG	CC	8,760	9 ppm/14 (w/DB) ppm	GCP		
Monroe Power Co.	GA	applic. under review	525	2	0	GE 7FA (170 MW)	NG	SC/CC	8,760	9 ppm	GCP		Initially SC, but later converting to CC
Peace Valley Generation Co., LLC	GA	applic. under review	1,550	6	4	F" Class	NG	CC/SC	8,760/2,500	10.6 ppm (25 ppm w/DB)	GCP		
Duke Energy Tift	GA	applic. under review	620	2	2	GE 7FA (170 MW)	NG	CC	8,760	24.1 ppm	GCP		SCONOx - $16,274/ton NO_x; CatOx - $2,095/ton CO
CPV Terrapin, LLC	GA	applic. under review	800	3	3	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	9 ppm NG; 13.6 ppm (NG w/DB); 24 ppm FO	GCP	24-hr rolling	
Kinder Morgan Georgia, LLC - Tift Power	GA	applic. under review	560	7	7	1 - GE 7EA & 6 - LM6000	NG	CC	8,760; 3,760 (part load)	158.5 lb/hr & 141.0 lb/hr	GCP		
Hartwell Development Co.	GA	applic. under review	564	2	0	GE 7FA (176 MW)	NG	CC	8,760	7.4 ppm	GCP		SCONOx - $35,422/ton NO_x; CatOx - $4,964/ton CO

Table B-7. Summary of BACT Determinations for CO for Combined Cycle CTs, 1999-2001

Facility	State	Final Permit Issued	# of New MW	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	CO Limit	Control Method	Avg. Time	Comments
Kentucky Pioneer Energy	KY	Jun-01	540	2	0	GE 7FA (197 MW)	syngas/ NG	CC	8,760	15/20 ppm	GCP	3-hr	
Duke Energy Hinds, L.L.C.	MS	Apr-00	520	2	0	GE 7FA (170 MW)	NG	CC	8,760	20 ppm	GCP		
Duke Energy Attala, L.L.C.	MS	Apr-00	520	2	0	GE 7FA (170 MW)	NG	CC	8,760	20 ppm	GCP		
Cogentrix Energy, Southaven Power Project	MS	draft permit	800	3	3	GE 7FA (170 MW)	NG	CC	8,760	9 ppm, 18 ppm w/ DB	GCP		
Cogentrix Energy, Caledonia Power Project	MS	Mar-01	800	3	3	GE 7FA (182 MW)	NG	CC	8,760	9 ppm	GCP		revised application to add SCR
GenPower - McAdams LLC	MS	draft permit	528	2	2	GE 7FA (170 MW)	NG	CC	8,760	7-8 ppm/13 ppm (w/DB)	GCP	24-hr	
Lone Oak Energy Center	MS	draft permit	800	3	3	F" Class (180 MW)	NG	CC	8,760	10/25/30/17 ppm	GCP		Base/PA/PA+DF/DF
Lee Power Partners	MS	draft permit	1,000	4	4	F" Class (170 MW)	NG	CC	8,760	25 ppm	GCP		
LSP-Pike Energy LLC	MS	draft permit	1,100	4	4	F" Class (170 MW)	NG	CC	8,760	33.1 ppm (0.15 lb/mmBTU)	GCP		
Magnolia Energy	MS	draft permit	900	3	3	F" Class (170 MW)	NG	CC	8,760	25 ppm	GCP		
Hines Energy Facility	MS	Jan-00	340	2	?	170 MW each	NG	CC	8,760	20 ppm	GCP		
Reliant Energy - Choctaw Co., LLC	MS	draft permit	844	3	3	GE 7FA (170 MW)	NG	CC	8,760	18.36 ppm	GCP		SCONOx - \$48,663/ton NO_x; CatOx - \$3,550/ton CO
Crossroads Energy Center	MS	applic. under review	580	2	2	GE 7FA (170 MW)	NG	CC	8,760	10.4 ppm	GCP		SCONOx - \$23,400/ton NO_x; CatOx - \$11,039/ton CO
Choctaw Gas Generation, LLC	MS	applic. under review	700	2	2	SW 501G (250 MW)	NG	CC	8,760	23 ppm	GCP		
Duke Energy Homochitto, LLC	MS	applic. under review	630	2	2	GE 7FA (170 MW)	NG	CC	8,760	20.4 ppm	GCP	24-hr	
Granite Power Partners II (Batesville)	MS	applic. under review	300	1	1	SW 501F (230 MW)	NG	CC	8,760	25 ppm	GCP		
Carolina Power & Light, Richmond Co. (2nd revision - new configuration)	NC	applic. under review	2,040	9	0	GE 7FA (170 MW)	NG; FO	CC/SC	8,760/2,000; 1,000 FO	9 ppm NG; 20 ppm FO	GCP		Reconfiguration of facility: 6 CC and 3 SC CTs
Carolina Power & Light, Rowan Co. (revision)	NC	draft permit	1,110	2	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 1,000 FO	15 ppm NG; 20 ppm FO	GCP		Modification of previous permit to switch 2 SC -> CC
Butler-Warner Generation Plant	NC	applic. under review	500	2	0	GE 7FA (170 MW)	NG; FO	SC & CC	8,760; 500 FO	9 ppm NG; 41 ppm FO	GCP		
GenPower Earleys, LLC	NC	applic. under review	528	2	2	GE 7FA (170 MW)	NG	CC	8,760	9 ppm (14 ppm w/DB)	GCP		SCONOx - \$21,942/ton NO_x; CatOx - \$3,246ton CO
Santee Cooper, Rainey Generating Station	SC	Apr-00	870	4	0	GE 7FA (170 MW)	NG, FO	2 CC, 2 SC	8,760; 1,000 FO	9 ppm NG; 20 ppm FO	GCP		
SC Electric & Gas - Urquhart	SC	Sep-00	444	2	0	GE 7FA (150 MW)	NG, FO	CC	8,760; 4,380 FO	12 ppm NG; 20 ppm FO	GCP		Netted out of NO_x, SO_2 and PM_{10} PSD Review
Columbia Energy	SC	Apr-01	515	2	2	GE 7FA (170 MW)	NG, FO	CC	8,760; 1,000 FO	17.4 ppm NG; 37 pm FO	GCP		SCONOx - no analysis; CatOx - \$1,611/ton CO
GenPower Anderson	SC	draft permit	640	2	2	GE 7FA (170 MW)	NG	CC	8760	11.7 ppm	GCP		
Vanderbilt University	TN	May-00	10	2	2	GE PGT5B (5.2 MW)	NG	CC	8,760	25 ppm	GCP		
Memphis Generation LLC	TN	draft permit	1,050	4	0	GE 7FA (170 MW)	NG	CC	8,760	0.03 lb/mmBtu	GCP		Phase I - 1 CT (up to 7% total plant heat input from refinery fuel gas), Phase II - 3 CTs (up to 2% total plant heat input from refinery fuel gas)

Table B-7. Summary of BACT Determinations for CO for Combined Cycle CTs, 1999-2001

Facility	State	Final Permit Issued	# of New MW	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	CO Limit	Control Method	Avg. Time	Comments
Haywood Energy Center (Calpine)	TN	applic. under review	900	3	3	SW, GE 7FA or GE F7B	NG; FO	CC	8,760	varies from 7.4 to 50 ppm depending on CT type and load	GCP		
TVA - Franklin	TN	applic. under review	610	2	2	GE 7FA (195 MW)		CC	8,760	25 ppm	GCP		

Abbreviations:
GE = General Electric
SW = Seimens Westinghouse
NG = Nat. Gas
FO = Fuel Oil
DB = Duct Burner
SC = Simple Cycle
CC = Combined Cycle
DLN = Dry-Low NOx
WI = Water Injection
SCR = Selective Catalytic Reduction
CatOx = Catalytic Oxidation
GCP = Good Combustion Practices

Source: http://www.epa.gov/region4/air/permits/national_ct_list.xls (2001)

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■ Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired. ■ Print your name and address on the reverse so that we can return the card to you. ■ Attach this card to the back of the mailpiece, or on the front if space permits.	A. Received by *(Please Print Clearly)* MICHAEL ROCK B. Date of Delivery 4-18-03 C. Signature X Michael Rock ☐ Agent ☐ Addressee D. Is delivery address different from item 1? ☐ Yes If YES, enter delivery address below: ☐ No
1. Article Addressed to: Mr. John M. Lindsay Plant General Manager Florida Power & Light Company Martin Power Plant Post Office Box 176 Indiantown, FL 34956	3. Service Type ☒ Certified Mail ☐ Express Mail ☐ Registered ☐ Return Receipt for Merchandise ☐ Insured Mail ☐ C.O.D. 4. Restricted Delivery? *(Extra Fee)* ☐ Yes
2. Article Number: 7001 0320 0001 3692 6488	

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Street, Apt. No.; or PO Box No. PO Box 176
City, State, ZIP+4 Indiantown, FL 34956

PS Form 3800, January 2001 See Reverse for Instructions

PUBLIC NOTICE OF INTENT TO ISSUE PSD PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

Draft Permit No. PSD-FL-327

FPL Martin Power Plant, New Combined Cycle Unit 8
Martin County

The Department of Environmental Protection (Department) gives notice of its intent to issue a permit under the requirements for the Prevention of Significant Deterioration (PSD) of Air Quality to the Florida Power and Light Company. The permit is one of several authorizations needed to construct a nominal 1150 MW combined cycle gas project at the FPL Martin Power Plant, which is located approximately 7 miles north of Indiantown on State Road 710 in Martin County, Florida. In accordance with Rule 62-212.400, F.A.C. and 40 CFR 52.21, Best Available Control Technology (BACT) determinations were required for emissions of carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), sulfuric acid mist (SAM), and volatile organic compounds (VOC). The applicant's authorized representative is Mr. John M. Lindsay, Plant General Manager. The applicant's address is FPL Martin Power Plant, P.O. Box 176, Indiantown, FL 34956.

The applicant proposes to construct a "4-on-1" combined cycle Unit 8 consisting of the following equipment and specifications: two existing 170 MW simple cycle gas turbine-electrical generator sets (8A and 8B), two new 170 MW gas turbine-electrical generator sets (8C and 8D), four gas-fired heat recovery steam generators (495 MMBtu/hour, LHV), a common steam-electrical generator (470 MW), two new gas-fired fuel heaters (22 MMBtu/hour, each), a cooling tower, and other associated support equipment. The gas turbines will be fired primarily with natural gas and up to 500 hours per year of very low sulfur distillate oil as a restricted alternate fuel. For the first year of operation, each gas turbine may operate in simple cycle mode for 3390 hours per year while the combined cycle components are constructed. Once combined cycle operation is established, simple cycle operation is limited to an average of 1000 hours per year. Additional equipment includes four 120-foot stacks combined cycle stacks, four 80-foot simple cycle stacks, and an aqueous ammonia storage tank.

During simple cycle operation and gas firing, NOx emissions will be controlled by dry low-NOx combustion technology. During simple cycle operation and oil firing, NOx emissions will be controlled by wet injection techniques. During the predominant combined cycle operation, a selective catalytic reduction (SCR) system with ammonia injection will be used in conjunction with dry low-NOx combustion (gas firing) and wet injection (oil firing) to further reduce NOx emissions. To meet peak power demands, the following alternate methods of operation will be authorized: high-temperature peaking (60 hours/year for simple cycle and 400 hours/year for combined cycle operation); steam injection for power augmentation (400 hours/year); and duct burning (2880 hours/year). During these restricted alternate methods of operation, NOx emissions are slightly higher. Emissions of CO, PM/PM_{10}, SAM, SO_2, and VOC will be minimized by the efficient, high-temperature combustion of very low sulfur fuels (natural gas and distillate oil). Emissions of CO and NOx will be continuously monitored to demonstrate compliance with the conditions of the permit. The Department determines that these control techniques and equipment represent the Best Available Control Technology (BACT) in accordance with Rule 62-212.400, F.A.C. and 40 CFR 52.21. Emissions standards are presented in the draft permit on file with the Department.

Based on the initial application, the maximum potential annual emissions from the combined cycle gas turbines, the gas fired-fuel heaters, and the cooling tower that comprise new Unit 8 are summarized in the following table. It is noted that some of the annual emissions estimates will be less because of lower standards specified in the DRAFT permit.

Pollutant	Maximum Tons Per Year	PSD Significant Emission Rate Tons Per Year	PSD Review Required?
CO	826	100	Yes
Pb	0.025	0.6	No
NOx	683	40	Yes
PM/PM_{10}	322/275	15/25	Yes
SO_2	280	40	Yes
SAM	30	7	Yes
VOC	110	40	Yes

According to the applicant, maximum predicted air quality impacts due to emissions from the proposed new project are less than the applicable PSD Class II significant impact levels, with the exception of 24-hour SO_2 impacts Therefore, multi-source modeling was only required for the 24-hour SO_2 impacts. The predicted impacts in the Everglades National Park are less than the applicable PSD Class I significant impact levels except for the 24-hour SO_2 impacts; therefore, multi-source Class I PSD increment modeling was only required for the 24-hour SO_2 impacts. The following table summarizes the maximum predicted PSD Class I and II 24-hour SO_2 increment consumed by the new project and by all increment-consuming sources.

Area and Averaging Time	Increment Consumed Project/All Sources (SO_2, ug/m^3)	Allowable Increment All Sources (SO_2, ug/m^3)	Increment Consumed Project/All Sources (Percent)
Class I, 24-hour (Everglades National Park)	0.4/3.5	5	8/70
Class II, 24-hour (Vicinity of Plant)	9/41	91	10/45

Based on the required analyses, the Department has reasonable assurance that the proposed project will not cause or significantly contribute to a violation of any ambient air quality standard or PSD increment. The Department will issue the FINAL Permit, in accordance with the conditions of the DRAFT Permit, unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments and requests for a public meeting concerning the proposed permit issuance action for a period of 30 (thirty) days from the date of publication of this Public Notice of Intent to Issue PSD Permit. Written comments or requests for public meetings should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below. This PSD permitting action is being coordinated with a certification under the Power Plant Siting Act (Sections 403.501-519, F.S.). If a petition for an administrative hearing on the Department's Intent to Issue is filed by a substantially affected person, that hearing shall be consolidated with the certification hearing, as provided under Section 403.507(3). Mediation is not available in this proceeding.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code.

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C. Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

A complete project file is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at:

Department of Environmental Protection Bureau of Air Regulation 111 S. Magnolia Drive, Suite 4 (Mailing Address: 2600 Blair Stone Road, MS #5505) Tallahassee, Florida 32399-2400 Telephone: 850/488-0114 Fax: 850/922-6979

Department of Environmental Protection Southeast District Office 400 North Congress Avenue (Mailing Address: P.O. Box 15425) West Palm Beach, FL 33416-5425 Telephone: 561/681-6600 Fax: 561/681-6790

The complete project file includes the application, technical evaluations, Draft Permit, and the information submitted by the authorized representative, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Manager of the New Resource Review Section at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114 for additional information. The draft permit, technical evaluation and preliminary BACT determination can be accessed at www.dep.state.fl.us/air/permitting/construct.htm.

PUBLIC NOTICE OF INTENT TO ISSUE PSD PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
Draft Permit No. PSD-FL-327
FPL Martin Power Plant, New Combined Cycle Unit 8
Martin County

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Department of Environmental Protection
Bureau of Air Regulation
111 S. Magnolia Drive, Suite 4
(Mailing Address: 2600 Blair Stone Road, MS #5505)
Tallahassee, Florida 32399-2400
Telephone: 850/488-0114
Fax: 850/922-6979

Department of Environmental Protection
Southeast District Office
400 North Congress Avenue
(Mailing Address: P.O. Box 15425)
West Palm Beach, FL 33416-5425
Telephone: 561/681-6600
Fax: 561/681-6790

The complete project file includes the application, technical evaluations, Draft Permit, and the information submitted by the authorized representative, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Manager of the New Resource Review Section at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114 for additional information. The draft permit, technical evaluation and preliminary BACT determination can be accessed at www.dep.state.fl.us/air/permitting/construct.htm.

Publish: September 12, 2002

2515577

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1. Article Addressed to:

Mr. John M. Lindsay
Plant General Manager
Florida Power & Light Company
Martin Power Plant
P.O. Box 176
Indiantown, FL 34956

COMPLETE THIS SECTION ON DELIVERY

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B. Date of Delivery 7-12-02

C. Signature
X Charles Malloy ☒ Agent ☐ Addressee

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Charles Malloy

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Sent To John M. Lindsay
Street, Apt. No.; or PO Box No. PO Box 176
City, State, ZIP+4 Indiantown, FL 34956

PS Form 3800, January 2001 See Reverse for Instructions

SENDER: *COMPLETE THIS SECTION*

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- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Mr. John M. Lindsay
Plant General Manager
Florida Power & Light - Martin Plant
P. O. Box 176
Indiantown, FL 34956

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)*

B. Date of Delivery

C. Signature

X Charles Ma

☐ Agent
☐ Addressee

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? *(Extra Fee)* ☐ Yes

2. 7001 0320 0001 3692 9281

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U.S. Postal Service
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OFFICIAL USE

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Certified Fee	
Return Receipt Fee (Endorsement Required)	
Restricted Delivery Fee (Endorsement Required)	
Total Postage & Fees	$

Postmark
Here

Sent To
John M. Lindsay
Street, Apt. No.; or PO Box No.
PO Box 176
City, State, ZIP+4
Indiantown, FL 34956

PS Form 3800, January 2001 See Reverse for Instructions