Progress Energy

December 1, 2004

RECEIVED

DEC 06 2004

BUREAU OF AIR REGULATION

Mr. Michael Halpin, P.E.
North Permitting Section
DARM/BAR
Florida Department of Environmental Protection
2600 Blair Stone Rd.
Tallahassee, Florida 32399-2400

RE: DRAFT PSD PERMIT NO. 1050234-010-AC
HINES ENERGY COMPLEX, POWER BLOCK 4

Dear Mr. Halpin:

Progress Energy Florida (PEF) is in receipt of your letter dated August 19, 2004. The letter indicates that the Department has begun review of our recent PSD application for the above-referenced facility. The Department has deemed the application incomplete due to the need for additional information. In addition, in a letter to the Department, dated November 4, 2004, PEF provided notification that a decision was made to use combustion turbines other than those generally represented in the original permit application. To more accurately describe the project, as it stands today, this letter also serves to transmit amended permit application forms (Attachment 1), revised emission tables (Attachment 2) and revised BACT tables for CO and NOx (Attachment 3).

The Department's requests and comments, per the August 19, 2004 letter, are addressed below in the order in which they were received.

<u>DEP Comment</u>

Progress has requested permission to operate for up to 3,000 hours per year below 60% output, however within Appendix A "Emission Estimates", data was provided for only the 100%, 80% and 60% (65% for distillate) output cases.

A) Please provide the same data for the 50% 30% and 10% CT output cases for natural gas.

B) Should Progress desire to be permitted for any operation below 65% CT output while firing distillate oil, then FDEP requires the same data (50%, 30% and 10% output) for the distillate oil cases.

C) Please indicate the lowest CT output (%) at which continuous operation is sought (on each fuel).

D) Please provide CT/HRSG/Steam Turbine heat balance diagrams (see attached 'example' from a conventional steam plant) for each of the CT outputs defined above (10%, 30%, 50%, 60%, 80%, and 100%).

Progress Energy Florida, Inc.
P.O. Box 14042
St. Petersburg, FL 33733

Response

As indicated above, during final equipment selection for this project, a decision was made to use combustion turbines other than those generally represented in the original permit application. The characteristics of the combustion turbine model selected (GE 7FA) are slightly different than those upon which the original application was based (SW 501F). The GE 7FA turbine model is able to meet defined emission characteristics within a load range of 50 to 100 percent of rated load on both fuels. The amended permit application, submitted in conjunction with this letter, provides data sufficient to address the Department's above comments.

Comparisons of the stack, operating, and emission data for natural gas-firing and distillate oil-firing for the GE 7FA combustion turbine to those for the SW 501F combustion turbine are presented in Tables 1 and 2, respectively. Details of the design information and stack parameters for the GE 7FA combustion turbines are presented in revised Tables A-1 to A-29 of Appendix 10.1.5 of the Site Certification Application (SCA). Information for firing natural gas in the combustion turbines are presented in Tables A-1 to A-12 for 100%, 75%, and 50% loads at ambient temperatures of 20°F, 59°F, and 95°F. Information for firing distillate fuel oil in the combustion turbines are presented in Tables A-13 to A-24 for 100%, 75%, and 50% loads at ambient temperatures of 20°F, 59°F, and 95°F. A summary of the maximum potential annual emissions for the two combustions turbines and one auxiliary boiler is presented in Table A-25. Supporting information for estimating formaldehyde emissions for the combustion turbines is presented in Tables A-26 to A-28. Finally, emission estimates for the auxiliary boiler are presented in Table A-29.

In general, PEF is requesting that no restrictions be placed on operations at any load, since continuous emissions monitoring of both NOx and CO will be performed. Demonstration of continuous compliance with these parameters is sufficient to restrict the overall operation of the unit.

Based on the maximum annual emissions presented in Table A-25, there will be a decrease in annual emissions for all pollutants except sulfur dioxide (SO_2) and nitrogen oxides (NO_x). For SO_2 and NO_x, the maximum increase in annual emissions are about 5 and 4 TPY, respectively, from those presented in the SCA. The increases in those pollutant emissions are primarily due to oil-firing. No additional Prevention of Significant Deterioration (PSD) review requirements will be triggered with the GE 7FA combustion turbines and auxiliary boiler. In fact, the volatile organic compound (VOC) emissions are estimated to be below the PSD significant emission rate of 40 TPY, requiring no PSD review for that pollutant.

In addition, no additional air quality impact analyses are required for the project with the GE 7FA combustion turbines since the air quality impacts for these turbines are expected to be similar to or lower than those predicted for the SW 501F combustion turbines. The exhaust gas flow rates, velocities, and temperatures for each combination of operating load and ambient temperature are higher for the GE 7FA turbines than those for the SW 501F turbines, resulting in more dilution and dispersion of the sources' plumes for the GE turbines. It should be noted that while the stack height remains the same for the GE turbine, the stack diameter is slightly smaller than that of the SW turbine (18 ft compared to 19 ft).

For natural gas-firing, since the maximum hourly emissions for the GE turbines are equal to or less than those for the SW turbines, the air quality impacts for the GE turbines will be lower than those for the SW turbines. For distillate oil-firing, the maximum hourly emissions for the GE turbines are also lower than those for the SW turbines except for SO_2 and NO_x. For SO_2, the maximum hourly emissions increase from about 3 percent at 20°F to 8 percent at 95 °F. For NO_x, the maximum hourly emissions increase from about 5 percent at 59°F to 8 percent at 95 °F. Even if the maximum air quality impacts for these pollutants were increased by 8 percent and no account was made for the increased exhaust gas flow rates and temperatures associated with the GE turbines, the air quality impacts for the GE turbines would still remain below the PSD Class II and I significant impact levels shown in Tables 5.6.1.-1 and 5.6.1-2 of the SCA (see also Tables 7-1 and 7-2 in Appendix 10.5.1). In addition, the 24-hour average visibility impairment and sulfur and nitrogen deposition predicted for the project are also expected to be below the trigger criteria that would require additional analyses (see Tables 8-5 and 8-6 in Appendix 10.5.1).

DEP Comment

Progress has requested up to eight hours per day of combined excess emissions for a cold start-up and up to five hours of combined excess emissions per day for any steam turbine shutdown. Further, Progress wishes to define a cold start-up as 'following a shutdown of the steam turbine lasting at least 48 hours.'

A) Based upon prior guidance from EPA Region 4, the department is not inclined to grant such lengthy time periods for unlimited excess emissions. Instead, the Department is will consider the development of alternative emission limits for routine operations where full-load emission limits cannot be achieved (this includes periods such as start-up and shut-downs, and perhaps even extended periods of operation during low load, as has been requested herein). In order for the Department to evaluate alternative emission limits for such operations, actual emission estimates will be required. Therefore, for any pollutant whereby Progress expects to be unable to meet a "full load" BACT established emission limit (but specifically during a steam turbine shutdown and cold start-up). The Department will need to be provided with estimated emission curves during those time periods. This should include each of the stages of event (e.g. cold startup) including the purpose, operating load, duration at that operating load, and estimated emissions at that operating load.

B) Please support the (above) proposed definition of a cold start-up ('following a shutdown of the steam turbine lasting at least 48 hours,) by providing:

1) The manufacturers criteria for what constitutes a cold start-up (e.g. turbine manufacturers typically identify the first stage metal temperature on the steam turbine) and
2) The additional operational measures which the equipment manufacturer requires to be taken as a result of the cold-start-up criteria being met.

Response

As the Department has indicated above, the development of alternative emission limits to address periods of non-routine operations, such as startup/shutdown is acceptable. PEF withdraws its request for allowable hours of excess emissions during startup/shutdown periods, contingent upon the development of acceptable alternative emission limits that cover these periods of operation. PEF requests the following alternative emissions limits, based on a 24-hour average:

NOx (gas): 125 lbs/hour
NOx (oil): 370 lbs/hour

CO (gas & oil): 175 lbs/hour

DEP Comment

Within Section 2 of the PSD application, Progress states "At present there are no confirmed test data of formaldehyde emissions from similar Siemens Westinghouse or equivalent combustion turbines". In order to be thorough, the Department requests that Progress contact the manufacturer (Siemens Westinghouse) to obtain test data for formaldehyde emissions on 501F machines. Should Westinghouse not have access to any such data, please request that they provide written confirmation to this effect.

Response

As previously indicated, PB 4 will be employing GE 7FA combustion turbines. GE was contacted and requested to address the Department's comment. Their response is provided as Attachment 4 to this letter.

DEP Comment

Regarding the proposed BACT Determination for CO:

A) Please confirm the evaluated placement position of the oxidation catalyst (within the flue gas stream) for Hines Power Block 4 is directly after the CT (and before the HRSG), as suggested in Appendix B, page 14. If this is not the desired placement, please specify the position in the flue gas stream as precisely as possible.

B) The Department notes the following discrepancies between the provided cost effectiveness calculation and the OAQPS Control Cost Manual:
   1) Indirect Costs are to be based upon a percentage of the Direct Capital Costs (TDCC in your supplied calculation), exclusive of the Direct Installation Costs (TDIC). The submitted evaluation shows indirect costs as based upon the sum of TDCC and TDIC (referred to as Total Capital Costs).
   2) The "Inventory Cost" associated with the Catalyst Replacement Cost is not an acceptable entry.
   3) The Capital Recovery (referred to as Annualized Total Direct Capital in the submitted evaluation) should exclude the initial cost of the catalyst (times freight and sales tax).
   4) Heat Rate Penalty – Please provide the Department with the assumed fuel cost (in $MMBtu) which was utilized as a basis for adding $3/MMBtu in the "Heat Rate Penalty" calculation.

C) Please provide the basis for the estimated net TPY of CO removed which was utilized in the submitted cost effectiveness of $3,773 per ton.

D) Please provide the basis for the estimated net TPY emission reduction, which was utilized in the submitted cost effectiveness of $4,070 per ton.

Response

A) While PEF is not proposing to install a CO catalyst, the power block will be constructed with space available to accommodate the installation of a CO catalyst, if required in the future. The proposed location to accommodate the potential future addition of a CO catalyst is within the HRSG, immediately prior to the SCR section.

B-1) The Indirect Costs for CO catalyst cost analysis have been revised to be a percentage of the Total Direct Capital Costs (TDCC). The CO catalyst cost analysis has also been revised to reflect final equipment selection of GE 7FA combustion turbines. The revised CO cost analysis (Tables B-8 to B-11) are included as Attachment 3 to this letter.

B-2) The "Inventory Cost" associated with the Catalyst Replacement Cost has been removed from the Annualized Cost Table.

B-3) The catalyst and the catalyst support system have different life expectancies, 3 years and 15 years, respectively. Therefore, the annualized cost for CO catalyst has been revised to reflect a capital recovery of 7% for 15 years for the "Total Direct, Indirect, and Capital" costs for the CO catalyst system minus the capital cost, sales tax, and shipping cost of the catalyst.

A separate annual cost for the catalyst has been estimated based on a capital recovery of 7% for 3 years, based on the life expectancy of the catalyst.

B-4) The addition of a CO catalyst adds back pressure to the system resulting in decreased MW output of the CT Unit. The CO catalyst is estimated to decrease the output by 0.2%, resulting in a corresponding 0.2% decrease in electricity sales. Based on a rated 181.7 MW CT output, the result is a loss of $159,170 per year. This loss is based on $0.05/kW per EPA's OAQPS Control Cost Manual.

In addition, a heat rate penalty of 0.2% results from the CO catalyst. Based on a heat input of 1,806 MMBtu/hr and an updated fuel cost of $6/MMBtu (see Attachment 5), the result is an additional fuel cost of $189,850 per year. Therefore, the total "Heat Rate Penalty" is equal to the loss in MW output plus the loss in heat input and is approximately $350,000 per year.

C) As stated previously, the CO catalyst cost analysis has been revised to reflect final equipment selection of GE 7FA combustion turbines. The revised cost effectiveness, based on GE CTs, is estimated to be $6,500 per ton CO removed. Reduced baseline CO emissions from the GE CTs compared to the Siemens Westinghouse CTs (9 ppmvd vs. 12 ppmvd and 20 ppmvd vs.30 ppmvd for gas and oil firing, respectively) result in a significantly higher cost effectiveness for GE Units. The basis for estimating the net TPY of CO removed resulting in the revised GE cost effectiveness of $6,500 per ton is as follows:

1. Uncontrolled Emissions = 148 TPY
    i. 9 ppmvd gas firing
    ii. 29.7 lb/hr gas firing, for 7,760 hour per year
    iii. 20 ppmvd oil firing
    iv. 66 lb/hr oil firing, for 1,000 hours per year
2. Controlled Emissions = 29 TPY
    i. 2.0 ppmvd gas firing
    ii. 80.5 % reduction

D) The basis for estimating the net TPY of CO removed that results in the revised GE cost effectiveness of $7,500 per ton is the total incremental emissions from Table B-11 equal to 103.5 TPY. The 103.5 TPY emissions include reduction of CO emissions and increase in PM, NO_x, and SO_2 emissions.

Attachment 3 also presents updated SCR and $SCONO_x$ cost analysis tables to reflect the final equipment selection of GE 7FA combustion turbines. As shown in Tables B-3 through B-6, the cost effectiveness of SCR with GE 7FA CTs is higher than the previously submitted Siemens Westinghouse CT analysis. The cost effectiveness is higher in GE CTs due to lower baseline emissions on gas (9 ppmvd for GE compared to 25 ppmvd for Siemens Westinghouse). As a result, the NO_x BACT analysis conclusions remain the same and are as follows:

The proposed BACT for combined cycle operation is advanced DLN combustion technology and SCR. The proposed NOx emissions level using this technology is 2.5 ppmvd corrected to 15 percent O_2 when firing natural gas and 10 ppmvd corrected to 15 percent O_2 when firing distillate fuel oil. This combination of 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.

The project also includes the addition of a 20 MMBtu/hr gas-fired auxiliary boiler. The auxiliary boiler will fire natural gas only and will be used primarily for cold startup of the combustion turbines. The auxiliary boiler will operate less than 500 hours per year. The emissions from the boiler are a result of the combustion process and trace elements in the fuel. Based on the size of the unit and expected annual operation, there are no technically or economically feasible methods for controlling emissions other than the inherent quality of the fuel. Therefore, BACT for the proposed auxiliary boiler is based on fuel quality specs and limiting operation to no more than 500 hours per year.

DEP Comment

Please note that EPA and NPS have been copied on your application, and should FDEP receive questions or comments from them, we will forward you a copy.

Response

As PEF has received no additional comments, it's our understanding that the EPA and the NPS have no further comments on the original application.

DEP Comment

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. Permit applicants are advised that Rule 62-213.420(1)(b), F.A.C., requires applicants to respond to requests for information within 90 days, unless the applicant has requested in writing, and has been granted, additional time within 90 days.

Response

In a letter to the Department, dated November 4, 2004, PEF had requested, and was granted, an extension of the 90 day timeframe, until December 3, 2004. This response, submitted within the approved timeframe, along with the associated permit application form revisions, signed and certified by a Florida PE, addresses the above comment.

PEF appreciates you consideration of the above responses. If you should have any questions, please don't hesitate to contact me at (727) 826-4363.

Sincerely,

Jamie Hunter
Lead Environmental Specialist
Environmental Services

Attachment

cc: Jim Pennington, FDEP- DARM/BAR
Hamilton Oven, FDEP- Siting
Scott Osbourn, P.E., Golder Associates Inc.
Roger Zirkle, Progress Energy Florida
C. Holladay
A. Walter, SWD
J. Bunyak, NPS
G. Worley, EPA

ATTACHMENT 1

Revised Application Forms

Department of Environmental Protection

Division of Air Resource Management

APPLICATION FOR AIR PERMIT - LONG FORM

I. APPLICATION INFORMATION

Air Construction Permit – Use this form to apply for an air construction permit for a proposed project:
- subject to prevention of significant deterioration (PSD) review, nonattainment area (NAA) new source review, or maximum achievable control technology (MACT) review; or
- where the applicant proposes to assume a restriction on the potential emissions of one or more pollutants to escape a federal program requirement such as PSD review, NAA new source review, Title V, or MACT; or
- at an existing federally enforceable state air operation permit (FESOP) or Title V permitted facility.

Air Operation Permit – Use this form to apply for:
- an initial federally enforceable state air operation permit (FESOP); or
- an initial/revised/renewal Title V air operation permit.

Air Construction Permit & Revised/Renewal Title V Air Operation Permit (Concurrent Processing Option) – Use this form to apply for both an air construction permit and a revised or renewal Title V air operation permit incorporating the proposed project.

To ensure accuracy, please see form instructions.

Identification of Facility

1. Facility Owner/Company Name: **Progress Energy Florida**	
2. Site Name: **Hines Energy Complex**	
3. Facility Identification Number: **1050234**	
4. Facility Location...: Street Address or Other Locator: **7700 County Road 555** City: **Bartow** County: **Polk** Zip Code: **33830**	
5. Relocatable Facility? ☐ Yes ☒ No	6. Existing Title V Permitted Facility? ☒ Yes ☐ No

Application Contact

1. Application Contact Name: **Jamie Hunter, Lead Environmental Specialist**
2. Application Contact Mailing Address... Organization/Firm: **Progress Energy Florida** Street Address: **PO Box 14042, MAC BB1A** City: **St. Petersburg** State: **FL** Zip Code: **33733-4042**
3. Application Contact Telephone Numbers... Telephone: **(727) 826-4363** ext. Fax: **(727) 826-4216**
4. Application Contact Email Address:

Application Processing Information (DEP Use)

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

APPLICATION INFORMATION

Purpose of Application

This application for air permit is submitted to obtain: (Check one)

Air Construction Permit

☒ Air construction permit.

Air Operation Permit

☐ Initial Title V air operation permit.
☐ Title V air operation permit revision.
☐ Title V air operation permit renewal.
☐ Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is required.
☐ Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is not required.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit (Concurrent Processing)

☐ Air construction permit and Title V permit revision, incorporating the proposed project.
☐ Air construction permit and Title V permit renewal, incorporating the proposed project.

Note: By checking one of the above two boxes, you, the applicant, are requesting concurrent processing pursuant to Rule 62-213.405, F.A.C. In such case, you must also check the following box:

☐ I hereby request that the department waive the processing time requirements of the air construction permit to accommodate the processing time frames of the Title V air operation permit.

Application Comment

Power Block 4 consists of two nominal 170 MW GE Frame 7FA combustion turbines (CTs), two unfired heat recovery steam generators (HRSGs), one 190 MW steam turbine; nominal rating of 530 MW combined cycle unit, and one 20 MMBtu/hr gas-fired auxiliary boiler. See PSD Application. Fee included with Site Certification Application.

Projected or Actual Date of Commencement of Construction: January 2006
Projected Date of Completion of Construction: December 2007

This application has been submitted and will be reviewed within the Florida Power Plant Siting Act (PPSA). See PSD Application. Power Block 1 has permit PA-92-33; PSD-FL-195A. Power Block 2 has permit PA-92-33SA; PSD-FL-296A. Power Block 3 has permit PA-92-33SA2; PSD-FL-330.

APPLICATION INFORMATION

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Proc. Fee
--	CT - 4A; Power Block 4	AC1A	
--	CT - 4B; Power Block 4	AC1A	
--	Auxiliary Boiler	AC1f	

Application Processing Fee

Check one: ☐ Attached - Amount: $________________ ☒ Not Applicable

APPLICATION INFORMATION

Owner/Authorized Representative Statement

Complete if applying for an air construction permit or an initial FESOP.

1. Owner/Authorized Representative Name : **Roger Zirkle, Plant Manager**	
2. Owner/Authorized Representative Mailing Address... Organization/Firm: Progress Energy Florida Street Address: **7700 County Road 555** City: **Bartow** State: **FL** Zip Code: **33830**	
3. Owner/Authorized Representative Telephone Numbers... Telephone: **(863) 519-6103** ext. Fax: **(863) 519-6110**	
4. Owner/Authorized Representative Email Address:	
5. Owner/Authorized Representative Statement: *I, the undersigned, am the owner or authorized representative of the facility addressed in this air permit application. 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 and all other requirements identified in this application to which the facility is subject. 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 the facility or any permitted emissions unit.* Roger B Zirkle Signature	12-3-04 Date

APPLICATION INFORMATION

Application Responsible Official Certification

Complete if applying for an initial/revised/renewal Title V permit or concurrent processing of an air construction permit and a revised/renewal Title V permit. If there are multiple responsible officials, the "application responsible official" need not be the "primary responsible official."

1. Application Responsible Official Name:
2. Application Responsible Official Qualification (Check one or more of the following options, as applicable): ☐ For a corporation, the president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit under Chapter 62-213, F.A.C. ☐ For a partnership or sole proprietorship, a general partner or the proprietor, respectively. ☐ For a municipality, county, state, federal, or other public agency, either a principal executive officer or ranking elected official. ☐ The designated representative at an Acid Rain source.
3. Application Responsible Official Mailing Address... Organization/Firm: Street Address: City: State: Zip Code:
4. Application Responsible Official Telephone Numbers... Telephone: ( ) - ext. Fax: ( ) -
5. Application Responsible Official Email Address:
6. Application Responsible Official Certification: I, the undersigned, am a responsible official of the Title V source addressed in this air permit application. 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 and all other applicable requirements identified in this application to which the Title V source is subject. 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 the facility or any permitted emissions unit. Finally, I certify that the facility and each emissions unit are in compliance with all applicable requirements to which they are subject, except as identified in compliance plan(s) submitted with this application. ________________ ____________ Signature Date

APPLICATION INFORMATION

Professional Engineer Certification

1.	Professional Engineer Name: **Scott Osbourn** Registration Number: **57557**
2.	Professional Engineer Mailing Address... Organization/Firm: **Golder Associates Inc.**** Street Address: **5100 West Lemon St., Suite 114** City: **Tampa** State: **FL** Zip Code: **33609**
3.	Professional Engineer Telephone Numbers... Telephone: **(813) 287-1717** ext.**211** Fax: **(813) 287-1716**
4.	Professional Engineer Email Address: **sosbourn@golder.com**
5.	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.

(3) If the purpose of this application is to obtain a Title V 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 plan and schedule is submitted with this application.

(4) If the purpose of this application is to obtain an air construction permit (check here ☒, if so) or concurrently process and obtain an air construction permit and a Title V air operation permit revision or renewal for one or more proposed new or modified emissions units (check here ☐, 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.

(5) If the purpose of this application is to obtain an initial air operation permit or operation permit revision or renewal 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.

[signature] 12/3/04

Signature Date

(seal)

SCOTT H. OSBOURN CERTIFICATE NO. 57557 STATE OF FLORIDA PROFESSIONAL ENGINEER

* Attach any exception to certification statement.
**** Board of Professional Engineers Certificate of Authorization #00001670**

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates... Zone **17** East (km) **414.4** North (km) **3073.9**		2. Facility Latitude/Longitude... Latitude (DD/MM/SS) **27 / 47 / 19** Longitude (DD/MM/SS) **81 / 52 / 10**	
3. Governmental Facility Code: **0**	4. Facility Status Code: **C**	5. Facility Major Group SIC Code: **49**	6. Facility SIC(s): **4911**
7. Facility Comment : **Operation of Power Block 1 began in 1999. Power Block 1 is a nominal 470 MW combined cycle unit consisting of 2 CTs, 2 HRSGs and 1 steam turbine. The CTs fire natural gas with distillate oil as backup. The HRSGs are unfired. Power Blocks 2 and 3 are each a nominal 530 MW combined-cycle generating unit consisting of 2 CTs, 2 HRSGs, and 1 steam turbine. This application is for the addition of Power Block 4, an additional nominal 530 MW combined-cycle application. See PSD Application.**			

Facility Contact

1. Facility Contact Name: **Roger Zirkle, Plant Manager**
2. Facility Contact Mailing Address... Organization/Firm: **Progress Energy Florida** Street Address: **7700 County Road 555** City: **Bartow** State: **FL** Zip Code: **33830**
3. Facility Contact Telephone Numbers: Telephone: **(863) 519-6103** ext. Fax: **(863) 519-6110**
4. Facility Contact Email Address:

Facility Primary Responsible Official

Complete if an "application responsible official" is identified in Section I. that is not the facility "primary responsible official."

1. Facility Primary Responsible Official Name:
2. Facility Primary Responsible Official Mailing Address... Organization/Firm: Street Address: City: State: Zip Code:
3. Facility Primary Responsible Official Telephone Numbers... Telephone: ( ) - ext. Fax: ( ) -
4. Facility Primary Responsible Official Email Address:

FACILITY INFORMATION

Facility Regulatory Classifications

Check all that would apply *following* completion of all projects and implementation of all other changes proposed in this application for air permit. Refer to instructions to distinguish between a "major source" and a "synthetic minor source."

1. ☐ Small Business Stationary Source	☐ Unknown
2. ☐ Synthetic Non-Title V Source	
3. ☐ Title V Source	
4. ☒ Major Source of Air Pollutants, Other than Hazardous Air Pollutants (HAPs)	
5. ☐ Synthetic Minor Source of Air Pollutants, Other than HAPs	
6. ☒ Major Source of Hazardous Air Pollutants (HAPs)	
7. ☐ Synthetic Minor Source of HAPs	
8. ☒ One or More Emissions Units Subject to NSPS (40 CFR Part 60)	
9. ☐ One or More Emissions Units Subject to Emission Guidelines (40 CFR Part 60)	
10. ☐ One or More Emissions Units Subject to NESHAP (40 CFR Part 61 or Part 63)	
11. ☐ Title V Source Solely by EPA Designation (40 CFR 70.3(a)(5))	
12. Facility Regulatory Classifications Comment: **Applicable NSPS: 40 CFR Part 60, Subpart GG, 40 CFR Part 60, Subpart Dc.** **62-212.400, F.A.C. See PSD Application.**	

FACILITY INFORMATION

List of Pollutants Emitted by Facility

1. Pollutant Emitted	2. Pollutant Classification	3. Emissions Cap [Y or N]?
Particulate Matter - PM	**A**	
Sulfur Dioxide -SO_2	**A**	
Nitrogen Oxides - NO_x	**A**	
Carbon Monoxide - CO	**A**	
Volatile Organic Compounds - VOC	**A**	
Sulfuric Acid Mist - SAM	**B**	

B. EMISSIONS CAPS

Facility-Wide or Multi-Unit Emissions Caps

1. Pollutant Subject to Emissions Cap	2. Facility Wide Cap [Y or N]? (all units)	3. Emissions Unit ID No.s Under Cap (if not all units)	4. Hourly Cap (lb/hr)	5. Annual Cap (ton/yr)	6. Basis for Emissions Cap
7. Facility-Wide or Multi-Unit Emissions Cap Comment:					

C. FACILITY ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Facility Plot Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID:**Fig 2-1, PSD** ☐ Previously Submitted, Date:____
2. Process Flow Diagram(s): (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID:**Fig 2-2, PSD** ☐ Previously Submitted, Date:____
3. Precautions to Prevent Emissions of Unconfined Particulate Matter: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID:**PSD Applic.** ☐ Previously Submitted, Date:____

Additional Requirements for Air Construction Permit Applications

1. Area Map Showing Facility Location: ☒ Attached, Document ID:**Fig 1-1, PSD** ☐ Not Applicable (existing permitted facility)
2. Description of Proposed Construction or Modification: ☐ Attached, Document ID:____
3. Rule Applicability Analysis: ☐ Attached, Document ID:____
4. List of Exempt Emissions Units (Rule 62-210.300(3)(a) or (b)1., F.A.C.): ☐ Attached, Document ID:____ ☒ Not Applicable (no exempt units at facility)
5. Fugitive Emissions Identification (Rule 62-212.400(2), F.A.C.): ☐ Attached, Document ID:____ ☒ Not Applicable
6. Preconstruction Air Quality Monitoring and Analysis (Rule 62-212.400(5)(f), F.A.C.): ☐ Attached, Document ID:____ ☒ Not Applicable
7. Ambient Impact Analysis (Rule 62-212.400(5)(d), F.A.C.): ☐ Attached, Document ID:____ ☒ Not Applicable
8. Air Quality Impact since 1977 (Rule 62-212.400(5)(h)5., F.A.C.): ☐ Attached, Document ID:____ ☒ Not Applicable
9. Additional Impact Analyses (Rules 62-212.400(5)(e)1. and 62-212.500(4)(e), F.A.C.): ☐ Attached, Document ID:____ ☒ Not Applicable
10. Alternative Analysis Requirement (Rule 62-212.500(4)(g), F.A.C.): ☐ Attached, Document ID:____ ☒ Not Applicable

FACILITY INFORMATION

Additional Requirements for FESOP Applications

1. List of Exempt Emissions Units (Rule 62-210.300(3)(a) or (b)1., F.A.C.): ☐ Attached, Document ID:____ ☒ Not Applicable (no exempt units at facility)	

Additional Requirements for Title V Air Operation Permit Applications

1. List of Insignificant Activities (Required for initial/renewal applications only): ☐ Attached, Document ID:____ ☒ Not Applicable (revision application)	
2. Identification of Applicable Requirements (Required for initial/renewal applications, and for revision applications if this information would be changed as a result of the revision being sought): ☐ Attached, Document ID:____ ☒ Not Applicable (revision application with no change in applicable requirements)	
3. Compliance Report and Plan (Required for all initial/revision/renewal applications): ☐ Attached, Document ID:____ Note: A compliance plan must be submitted for each emissions unit that is not in compliance with all applicable requirements at the time of application and/or at any time during application processing. The department must be notified of any changes in compliance status during application processing.	
4. List of Equipment/Activities Regulated under Title VI (If applicable, required for initial/renewal applications only): ☐ Attached, Document ID:____ ☐ Equipment/Activities On site but Not Required to be Individually Listed ☒ Not Applicable	
5. Verification of Risk Management Plan Submission to EPA (If applicable, required for initial/renewal applications only) : ☐ Attached, Document ID:____ ☒ Not Applicable	
6. Requested Changes to Current Title V Air Operation Permit: ☐ Attached, Document ID:____ ☒ Not Applicable	

Additional Requirements Comment

III. EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Application - For Title V air operation permitting only, emissions units are classified as regulated, unregulated, or insignificant. If this is an application for Title V air operation permit, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each regulated and unregulated emissions unit addressed in this application for air permit. Some of the subsections comprising the Emissions Unit Information Section of the form are optional for unregulated emissions units. Each such subsection is appropriately marked. Insignificant emissions units are required to be listed at Section II, Subsection C.

Air Construction Permit or FESOP Application - For air construction permitting or federally enforceable state air operation permitting, emissions units are classified as either subject to air permitting or exempt from air permitting. The concept of an "unregulated emissions unit" does not apply. If this is an application for air construction permit or FESOP, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air permitting are required to be listed at Section II, Subsection C.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit Application – Where this application is used to apply for both an air construction permit and a revised/renewal Title V air operation permit, each emissions unit is classified as either subject to air permitting or exempt from air permitting for air construction permitting purposes and as regulated, unregulated, or insignificant for Title V air operation permitting purposes. **The air construction permitting classification must be used to complete the Emissions Unit Information Section of this application for air permit.** A separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air construction permitting and insignificant emissions units are required to be listed at Section II, Subsection C.

If submitting the application form in hard copy, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application must be indicated in the space provided at the top of each page.

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

   ☒ 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.

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).

   ☐ 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. Description of Emissions Unit Addressed in this Section:
   CT-4A; Power Block 4

3. Emissions Unit Identification Number:

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
C			**49**	☒ Yes ☐ No

9. Package Unit: **GE Frame 7FA**
   Manufacturer: **GE** Model Number: **Frame 7FA**

10. Generator Nameplate Rating: **170** MW

11. Emissions Unit Comment:
    GE Frame 7FA combustion turbine firing natural gas with distillate oil back up.

Emissions Unit Control Equipment

1.	Control Equipment/Method(s) Description: **Dry Low NO_X combustion-natural gas firing** **Selective Catalytic Reduction (SCR) – natural gas firing/ distillate oil firing.** **Water Injection – distillate oil firing**
2.	Control Device or Method Code(s): **25, 65, 28**

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:	
2. Maximum Production Rate:	
3. Maximum Heat Input Rate: **1,806** million Btu/hr	
4. Maximum Incineration Rate: pounds/hr tons/day	
5. Requested Maximum Operating Schedule: hours/day weeks/year	days/week **8,760** hours/year
6. Operating Capacity/Schedule Comment: **Heat input at HHV, 59°F turbine inlet temperature and 100% load; For oil firing, heat input is 1,962 MMBtu/hr (HHV) at 59°F turbine inlet temperature and 100% load; MW nominal rating.**	

C. EMISSION POINT (STACK/VENT) INFORMATION
(Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: **Fig 2-1**		2. Emission Point Type Code: **1**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: **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: **125** feet	7. Exit Diameter: **18** feet
8. Exit Temperature: **202**°F	9. Actual Volumetric Flow Rate: **1,036,271** 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): **414.4** North (km): **3073.9**		14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)
15. Emission Point Comment: **Temperature and flow for natural gas at 59°F turbine inlet; See Tables 1 and 2 and revised Appendix A for PSD application.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type): **Natural Gas**		
2. Source Classification Code (SCC): **2-01-002-01**	3. SCC Units: **Million Cubic Feet**	
4. Maximum Hourly Rate: **1.90**	5. Maximum Annual Rate: **15,507**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **1,021**
10. Segment Comment: **Based on 1,021 Btu/CF (HHV); maximum hourly at 20°F; annual at 59°F; turbine inlet temperatures.**		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type): **Distillate Fuel Oil**		
2. Source Classification Code (SCC): **2-01-001-01**	3. SCC Units: **Thousand Gallons Used**	
4. Maximum Hourly Rate: **16.3**	5. Maximum Annual Rate: **15,352**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **127.8**
10. Segment Comment: **Btu based on HHV of 127.8 MMBtu/1,000 gallons and density of 6.7 lb/gal; maximum hourly at 20°F; annual at 59°F. Aggregate fuel usage of 30,700,000 gallons per year requested for Power Block 4, equates to 1,000 hr/CT/yr.**		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM			
SO_2			
NO_x	025, 028	065	EL
CO			EL
VOC			EL
SAM			

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **39.1** lb/hour **57.8** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: **GE, 2004**	7. Emissions Method Code: **2**
8. Calculation of Emissions: **See Tables 1 and 2 and revised Appendix A for PSD Application.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Max lb/hr for oil firing at 20°F turbine inlet; TPY at 59°F turbine inlet with 7,760 hrs/yr-gas; equivalent of 1,000 hrs/yr/CT-oil.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **10% opacity**	4. Equivalent Allowable Emissions: **10.1** lb/hour **44.0** tons/year
5. Method of Compliance: **EPA Method 9; initially and annually.**	
6. Allowable Emissions Comment (Description of Operating Method): **Gas Firing: lb/hr at 20°F turbine inlet; TPY for 8,760 hrs/yr at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **20% opacity**	4. Equivalent Allowable Emissions: **39.1** lb/hour **18.9** tons/year
5. Method of Compliance: **EPA Method 9; when oil firing greater than 400 hr/yr.**	
6. Allowable Emissions Comment (Description of Operating Method): **Oil firing: lb/hr at 20°F turbine inlet; TPY equivalent of 1,000 hrs/yr/CT-oil at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **SO_2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **109.2** lb/hour **71.0** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: **GE, 2004**	7. Emissions Method Code: **2**
8. Calculation of Emissions: **See Tables 1 and 2 and revised Appendix A for PSD Application.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Max lb/hr for oil firing at 20°F turbine inlet; TPY at 59°F turbine inlet with 7,760 hrs/yr-gas; equivalent of 1,000 hrs/yr/CT-oil.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **Natural Gas**	4. Equivalent Allowable Emissions: **5.4** lb/hour **22.1** tons/year
5. Method of Compliance: **Fuel Sampling - Vendor or Applicant**	
6. Allowable Emissions Comment (Description of Operating Method): **Gas Firing: lb/hr at 20°F turbine inlet; TPY for 8,760 hrs/yr at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.05% Sulfur Oil**	4. Equivalent Allowable Emissions: **109.2** lb/hour **56.4** tons/year
5. Method of Compliance: **Fuel Sampling - Vendor or Applicant**	
6. Allowable Emissions Comment (Description of Operating Method): **Oil Firing: lb/hr at 20°F turbine inlet; TPY equivalent of 1,000 hrs/yr/CT-oil at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **82.4** lb/hour **102.4** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: **GE, 2004**	7. Emissions Method Code: **2**
8. Calculation of Emissions: **See Tables 1 and 2 and revised Appendix A for PSD Application.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Max lb/hr for oil firing at 20°F turbine inlet; TPY at 59°F turbine inlet with 7,760 hrs/yr-gas; equivalent of 1,000 hrs/yr/CT-oil.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **2.5 ppmvd at 15% O_2**	4. Equivalent Allowable Emissions: **17.7** lb/hour **72.3** tons/year
5. Method of Compliance: **CEM; part 75; 24-hour block average; midnight to midnight**	
6. Allowable Emissions Comment (Description of Operating Method): **Gas Firing: lb/hr at 20°F turbine inlet; TPY for 8,760 hrs/yr at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **10 ppmvd at 15% O_2**	4. Equivalent Allowable Emissions: **82.4** lb/hour **38.4** tons/year
5. Method of Compliance: **CEM; part 75; 24-hour block average; midnight to midnight**	
6. Allowable Emissions Comment (Description of Operating Method): **Oil firing: lb/hr at 20°F turbine inlet; TPY equivalent of 1,000 hrs/yr/CT-oil at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **71.4**lb/hour **148** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: **GE, 2004**	7. Emissions Method Code: **2**
8. Calculation of Emissions: **See Tables 1 and 2 and revised Appendix A for PSD Application.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Max lb/hr for oil firing at 20°F turbine inlet; TPY at 59°F turbine inlet with 7,760 hrs/yr-gas; equivalent of 1,000 hrs/yr/CT-oil.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **8 ppmvd at 15% O_2**	4. Equivalent Allowable Emissions: **32.1** lb/hour **130** tons/year
5. Method of Compliance: **EPA Method 10; based on 9 ppmvd**	
6. Allowable Emissions Comment (Description of Operating Method): **Gas Firing: lb/hr at 20°F turbine inlet; TPY for 8,760 hrs/yr at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **15 ppmvd at 15% O_2**	4. Equivalent Allowable Emissions: **71.4** lb/hour **33** tons/year
5. Method of Compliance: **EPA Method 10; based on 20 ppmvd; Initial and Annual at Base Load**	
6. Allowable Emissions Comment (Description of Operating Method): **Oil firing: lb/hr at 20°F turbine inlet; TPY equivalent of 1,000 hrs/yr/CT-oil at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **8.0** lb/hour **14.9** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: **GE, 2004**	7. Emissions Method Code: **2**
8. Calculation of Emissions: **See Tables 1 and 2 and revised Appendix A for PSD Application.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Max lb/hr for oil firing at 20°F turbine inlet; TPY at 59°F turbine inlet with 7,760 hrs/yr-gas; equivalent of 1,000 hrs/yr/CT-oil.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **1.3 ppmvd at 15% O_2**	4. Equivalent Allowable Emissions: **3.1** lb/hour **12.6**tons/year
5. Method of Compliance: **EPA Method 25A; based on 1.4 ppmvw**	
6. Allowable Emissions Comment (Description of Operating Method): **Gas Firing: lb/hr at 20°F turbine inlet; TPY for 8,760 hrs/yr at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **3 ppmvd at 15% O_2**	4. Equivalent Allowable Emissions: **8.0** lb/hour **3.7** tons/year
5. Method of Compliance: **EPA Method 25A; based on 3.5 ppmvw**	
6. Allowable Emissions Comment (Description of Operating Method): **Oil firing: lb/hr at 20°F turbine inlet; TPY equivalent of 1,000 hrs/yr/CT-oil at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **SAM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **16.7** lb/hour **10.9** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **10% SO_2** Reference: **Golder, 2004**	7. Emissions Method Code: **2**
8. Calculation of Emissions: **Emission Factor is converted to SAM. See Tables 1 and 2 and revised Appendix A in PSD Application.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Max lb/hr for oil firing at 20°F turbine inlet; TPY at 59°F turbine inlet with 7,760 hrs/yr-gas; equivalent of 1,000 hrs/yr/CT-oil.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **Natural Gas**	4. Equivalent Allowable Emissions: **0.83** lb/hour **3.4** tons/year
5. Method of Compliance: **Fuel Sampling - Vendor or Applicant**	
6. Allowable Emissions Comment (Description of Operating Method): **Gas Firing: lb/hr at 20°F turbine inlet; TPY for 8,760 hrs/yr at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.05% Sulfur oil**	4. Equivalent Allowable Emissions: **16.7** lb/hour **7.85** tons/year
5. Method of Compliance: **Fuel Sampling - Vendor or Applicant**	
6. Allowable Emissions Comment (Description of Operating Method): **Oil firing: lb/hr at 20°F turbine inlet; TPY equivalent of 1,000 hrs/yr/CT-oil at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

G. VISIBLE EMISSIONS INFORMATION

Complete if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation 1 of 3

1. Visible Emissions Subtype: **VE10**	2. Basis for Allowable Opacity: ☐ Rule ☒ Other
3. Allowable Opacity: Normal Conditions: **10** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **EPA Method 9.**	
5. Visible Emissions Comment: **Gas Firing**	

Visible Emissions Limitation: Visible Emissions Limitation 2 of 3

1. Visible Emissions Subtype: **VE 20**	2. Basis for Allowable Opacity: ☐ Rule ☒ Other
3. Allowable Opacity: Normal Conditions: **20** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **EPA Method 9.**	
5. Visible Emissions Comment: **Oil Firing**	

G. VISIBLE EMISSIONS INFORMATION

Complete if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation 3 of 3

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

Visible Emissions Limitation: Visible Emissions Limitation ____ of ____

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

H. CONTINUOUS MONITOR INFORMATION

Complete if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor 1 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **NO_x**
3. CMS Requirement: ☒ Rule ☐ Other	
4. Monitor Information... Manufacturer: **Not yet determined** Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **NO_x CEM required by 40 CFR Part 75. A carbon dioxide or oxygen monitor will be included.**	

Continuous Monitoring System: Continuous Monitor 2 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **NO_x**
3. CMS Requirement: ☒ Rule ☐ Other	
4. Monitor Information... Manufacturer: **GE or equivalent** Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **Parameter Code: WTF. Required by 40 CFR 60; Subpart GG; S.60.334; oil firing. Request Part 75 NO_x CEM in lieu of WTF monitoring.**	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **Fig 2-2** ☐ Previously Submitted, Date ____

2. Fuel Analysis or Specification (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **Tables 2-4/2-5** ☐ Previously Submitted, Date ____

3. Detailed Description of Control Equipment (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **Section 4.0** ☐ Previously Submitted, Date ____

4. Procedures for Startup and Shutdown (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date ____
   ☒ Not Applicable (construction application)

5. Operation and Maintenance Plan (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date ____
   ☒ Not Applicable

6. Compliance Demonstration Reports/Records
   ☐ Attached, Document ID: ____
   Test Date(s)/Pollutant(s) Tested: ____

   ☐ Previously Submitted, Date: ____
   Test Date(s)/Pollutant(s) Tested: ____

   ☐ To be Submitted, Date (if known): ____
   Test Date(s)/Pollutant(s) Tested: ____

   ☒ Not Applicable

   Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.

7. Other Information Required by Rule or Statute
   ☒ Attached, Document ID: **See PSD Application** ☐ Not Applicable

EMISSIONS UNIT INFORMATION
Section [1] of [3]
CT-4A; Power Block 4

Additional Requirements for Air Construction Permit Applications

1. Control Technology Review and Analysis (Rules 62-212.400(6) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)) ☐ Attached, Document ID: ____ ☒ Not Applicable	
2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(5)(h)6., F.A.C., and Rule 62-212.500(4)(f), F.A.C.) ☐ Attached, Document ID: ____ ☒ Not Applicable	
3. Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only) ☒ Attached, Document ID: **See PSD Application** ☐ Not Applicable	

Additional Requirements for Title V Air Operation Permit Applications

1. Identification of Applicable Requirements ☐ Attached, Document ID: ____ ☒ Not Applicable	
2. Compliance Assurance Monitoring ☐ Attached, Document ID: ____ ☒ Not Applicable	
3. Alternative Methods of Operation ☐ Attached, Document ID: ____ ☒ Not Applicable	
4. Alternative Modes of Operation (Emissions Trading) ☐ Attached, Document ID: ____ ☒ Not Applicable	
5. Acid Rain Part Application ☐ Certificate of Representation (EPA Form No. 7610-1) ☐ Copy Attached, Document ID: ____ ☐ Acid Rain Part (Form No. 62-210.900(1)(a)) ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date: ____ ☐ Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date: ____ ☐ New Unit Exemption (Form No. 62-210.900(1)(a)2.) ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date: ____ ☐ Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date: ____ ☐ Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date: ____ ☐ Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date: ____ ☒ Not Applicable	

Additional Requirements Comment

III. EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Application - For Title V air operation permitting only, emissions units are classified as regulated, unregulated, or insignificant. If this is an application for Title V air operation permit, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each regulated and unregulated emissions unit addressed in this application for air permit. Some of the subsections comprising the Emissions Unit Information Section of the form are optional for unregulated emissions units. Each such subsection is appropriately marked. Insignificant emissions units are required to be listed at Section II, Subsection C.

Air Construction Permit or FESOP Application - For air construction permitting or federally enforceable state air operation permitting, emissions units are classified as either subject to air permitting or exempt from air permitting. The concept of an "unregulated emissions unit" does not apply. If this is an application for air construction permit or FESOP, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air permitting are required to be listed at Section II, Subsection C.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit Application – Where this application is used to apply for both an air construction permit and a revised/renewal Title V air operation permit, each emissions unit is classified as either subject to air permitting or exempt from air permitting for air construction permitting purposes and as regulated, unregulated, or insignificant for Title V air operation permitting purposes. **The air construction permitting classification must be used to complete the Emissions Unit Information Section of this application for air permit.** A separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air construction permitting and insignificant emissions units are required to be listed at Section II, Subsection C.

If submitting the application form in hard copy, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application must be indicated in the space provided at the top of each page.

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

   ☒ 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.

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).

   ☐ 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. Description of Emissions Unit Addressed in this Section:
   CT-4B; Power Block 4

3. Emissions Unit Identification Number:

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
C			**49**	☒ Yes ☐ No

9. Package Unit: **GE Frame 7FA**
   Manufacturer: **GE** Model Number: **Frame 7FA**

10. Generator Nameplate Rating: **170** MW

11. Emissions Unit Comment:
   GE Frame 7FA combustion turbine firing natural gas with distillate oil back up.

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description: **Dry Low NO_X combustion-natural gas firing** **Selective Catalytic Reduction (SCR) – natural gas firing/ distillate oil firing.** **Water Injection – distillate oil firing**	
2. Control Device or Method Code(s): **25, 65, 28**	

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:		
2. Maximum Production Rate:		
3. Maximum Heat Input Rate: 1,806 million Btu/hr		
4. Maximum Incineration Rate:	pounds/hr tons/day	
5. Requested Maximum Operating Schedule:	hours/day weeks/year	days/week 8,760 hours/year
6. Operating Capacity/Schedule Comment: Heat input at HHV, 59°F turbine inlet temperature and 100% load; For oil firing, heat input is 1,962 MMBtu/hr (HHV) at 59°F turbine inlet temperature and 100% load; MW nominal rating.		

C. EMISSION POINT (STACK/VENT) INFORMATION
(Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: **Fig 2-1**		2. Emission Point Type Code: **1**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: **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: **125** feet	7. Exit Diameter: **18** feet
8. Exit Temperature: **202**°F	9. Actual Volumetric Flow Rate: **1,036,271** 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): **414.4** North (km): **3073.9**		14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)
15. Emission Point Comment: **Temperature and flow for natural gas at 59°F turbine inlet; See Tables 1 and 2 and revised Appendix A for PSD application.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type): **Natural Gas**		
2. Source Classification Code (SCC): **2-01-002-01**	3. SCC Units: **Million Cubic Feet**	
4. Maximum Hourly Rate: **1.90**	5. Maximum Annual Rate: **15,507**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **1,021**
10. Segment Comment: **Based on 1,021 Btu/CF (HHV); maximum hourly at 20°F; annual at 59°F; turbine inlet temperatures.**		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type): **Distillate Fuel Oil**		
2. Source Classification Code (SCC): **2-01-001-01**	3. SCC Units: **Thousand Gallons Used**	
4. Maximum Hourly Rate: **16.3**	5. Maximum Annual Rate: **15,352**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **127.8**
10. Segment Comment: **Btu based on HHV of 127.8 MMBtu/1,000 gallons and density of 6.7 lb/gal; maximum hourly at 20°F; annual at 59°F. Aggregate fuel usage of 30,700,000 gallons per year requested for Power Block 4, equates to 1,000 hr/CT/yr.**		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM			
SO_2			
NO_x	025, 028	065	EL
CO			EL
VOC			EL
SAM			

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **39.1** lb/hour **57.8** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: **GE, 2004**	7. Emissions Method Code: **2**
8. Calculation of Emissions: **See Tables 1 and 2 and revised Appendix A for PSD Application.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Max lb/hr for oil firing at 20°F turbine inlet; TPY at 59°F turbine inlet with 7,760 hrs/yr-gas; equivalent of 1,000 hrs/yr/CT-oil.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **10% opacity**	4. Equivalent Allowable Emissions: **10.1** lb/hour **44.0** tons/year
5. Method of Compliance: **EPA Method 9; initially and annually.**	
6. Allowable Emissions Comment (Description of Operating Method): **Gas Firing: lb/hr at 20°F turbine inlet; TPY for 8,760 hrs/yr at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **20% opacity**	4. Equivalent Allowable Emissions: **39.1** lb/hour **18.9** tons/year
5. Method of Compliance: **EPA Method 9; when oil firing greater than 400 hr/yr.**	
6. Allowable Emissions Comment (Description of Operating Method): **Oil firing: lb/hr at 20°F turbine inlet; TPY equivalent of 1,000 hrs/yr/CT-oil at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **SO_2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **109.2** lb/hour **71.0** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: **GE, 2004**	7. Emissions Method Code: **2**
8. Calculation of Emissions: **See Tables 1 and 2 and revised Appendix A for PSD Application.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Max lb/hr for oil firing at 20°F turbine inlet; TPY at 59°F turbine inlet with 7,760 hrs/yr-gas; equivalent of 1,000 hrs/yr/CT-oil.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **Natural Gas**	4. Equivalent Allowable Emissions: **5.4** lb/hour **22.1** tons/year
5. Method of Compliance: **Fuel Sampling - Vendor or Applicant**	
6. Allowable Emissions Comment (Description of Operating Method): **Gas Firing: lb/hr at 20°F turbine inlet; TPY for 8,760 hrs/yr at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.05% Sulfur Oil**	4. Equivalent Allowable Emissions: **109.2** lb/hour **56.4** tons/year
5. Method of Compliance: **Fuel Sampling - Vendor or Applicant**	
6. Allowable Emissions Comment (Description of Operating Method): **Oil Firing: lb/hr at 20°F turbine inlet; TPY equivalent of 1,000 hrs/yr/CT-oil at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **82.4** lb/hour **102.4** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: **GE, 2004**	7. Emissions Method Code: **2**
8. Calculation of Emissions: **See Tables 1 and 2 and revised Appendix A for PSD Application.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Max lb/hr for oil firing at 20°F turbine inlet; TPY at 59°F turbine inlet with 7,760 hrs/yr-gas; equivalent of 1,000 hrs/yr/CT-oil.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **2.5 ppmvd at 15% O_2**	4. Equivalent Allowable Emissions: **17.7** lb/hour **72.3** tons/year
5. Method of Compliance: **CEM; part 75; 24-hour block average; midnight to midnight**	
6. Allowable Emissions Comment (Description of Operating Method): **Gas Firing: lb/hr at 20°F turbine inlet; TPY for 8,760 hrs/yr at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **10 ppmvd at 15% O_2**	4. Equivalent Allowable Emissions: **82.4** lb/hour **38.4** tons/year
5. Method of Compliance: **CEM; part 75; 24-hour block average; midnight to midnight**	
6. Allowable Emissions Comment (Description of Operating Method): **Oil firing: lb/hr at 20°F turbine inlet; TPY equivalent of 1,000 hrs/yr/CT-oil at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **71.4**lb/hour **148** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: **GE, 2004**	7. Emissions Method Code: **2**
8. Calculation of Emissions: **See Tables 1 and 2 and revised Appendix A for PSD Application.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Max lb/hr for oil firing at 20°F turbine inlet; TPY at 59°F turbine inlet with 7,760 hrs/yr-gas; equivalent of 1,000 hrs/yr/CT-oil.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **8 ppmvd at 15% O_2**	4. Equivalent Allowable Emissions: **32.1** lb/hour **130** tons/year
5. Method of Compliance: **EPA Method 10; based on 9 ppmvd**	
6. Allowable Emissions Comment (Description of Operating Method): **Gas Firing: lb/hr at 20°F turbine inlet; TPY for 8,760 hrs/yr at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **15 ppmvd at 15% O_2**	4. Equivalent Allowable Emissions: **71.4** lb/hour **33** tons/year
5. Method of Compliance: **EPA Method 10; based on 20 ppmvd; Initial and Annual at Base Load**	
6. Allowable Emissions Comment (Description of Operating Method): **Oil firing: lb/hr at 20°F turbine inlet; TPY equivalent of 1,000 hrs/yr/CT-oil at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **8.0** lb/hour **14.9** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: **GE, 2004**	7. Emissions Method Code: **2**
8. Calculation of Emissions: **See Tables 1 and 2 and revised Appendix A for PSD Application.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Max lb/hr for oil firing at 20°F turbine inlet; TPY at 59°F turbine inlet with 7,760 hrs/yr-gas; equivalent of 1,000 hrs/yr/CT-oil.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **1.3 ppmvd at 15% O_2**	4. Equivalent Allowable Emissions: **3.1** lb/hour **12.6**tons/year
5. Method of Compliance: **EPA Method 25A; based on 1.4 ppmvw**	
6. Allowable Emissions Comment (Description of Operating Method): **Gas Firing: lb/hr at 20°F turbine inlet; TPY for 8,760 hrs/yr at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **3 ppmvd at 15% O_2**	4. Equivalent Allowable Emissions: **8.0** lb/hour **3.7** tons/year
5. Method of Compliance: **EPA Method 25A; based on 3.5 ppmvw**	
6. Allowable Emissions Comment (Description of Operating Method): **Oil firing: lb/hr at 20°F turbine inlet; TPY equivalent of 1,000 hrs/yr/CT-oil at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **SAM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **16.7** lb/hour **10.9** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **10% SO_2** Reference: **Golder, 2004**	7. Emissions Method Code: **2**
8. Calculation of Emissions: **Emission Factor is converted to SAM. See Tables 1 and 2 and revised Appendix A in PSD Application.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Max lb/hr for oil firing at 20°F turbine inlet; TPY at 59°F turbine inlet with 7,760 hrs/yr-gas; equivalent of 1,000 hrs/yr/CT-oil.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **Natural Gas**	4. Equivalent Allowable Emissions: **0.83** lb/hour **3.4** tons/year
5. Method of Compliance: **Fuel Sampling - Vendor or Applicant**	
6. Allowable Emissions Comment (Description of Operating Method): **Gas Firing: lb/hr at 20°F turbine inlet; TPY for 8,760 hrs/yr at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.05% Sulfur oil**	4. Equivalent Allowable Emissions: **16.7** lb/hour **7.85** tons/year
5. Method of Compliance: **Fuel Sampling - Vendor or Applicant**	
6. Allowable Emissions Comment (Description of Operating Method): **Oil firing: lb/hr at 20°F turbine inlet; TPY equivalent of 1,000 hrs/yr/CT-oil at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

G. VISIBLE EMISSIONS INFORMATION

Complete if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation 1 of 3

1. Visible Emissions Subtype: **VE10**	2. Basis for Allowable Opacity: ☐ Rule ☒ Other
3. Allowable Opacity: Normal Conditions: **10** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **EPA Method 9.**	
5. Visible Emissions Comment: **Gas Firing**	

Visible Emissions Limitation: Visible Emissions Limitation 2 of 3

1. Visible Emissions Subtype: **VE 20**	2. Basis for Allowable Opacity: ☐ Rule ☒ Other
3. Allowable Opacity: Normal Conditions: **20** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **EPA Method 9.**	
5. Visible Emissions Comment: **Oil Firing**	

G. VISIBLE EMISSIONS INFORMATION

Complete if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation 3 of 3

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

Visible Emissions Limitation: Visible Emissions Limitation ____ of ____

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

H. CONTINUOUS MONITOR INFORMATION

Complete if this emissions unit is or would be subject to continuous monitoring.

<u>Continuous Monitoring System:</u> Continuous Monitor 1 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **NO_x**
3. CMS Requirement: ☒ Rule ☐ Other	
4. Monitor Information... Manufacturer: **Not yet determined** Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **NO_x CEM required by 40 CFR Part 75. A carbon dioxide or oxygen monitor will be included.**	

<u>Continuous Monitoring System:</u> Continuous Monitor 2 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **NO_x**
3. CMS Requirement: ☒ Rule ☐ Other	
4. Monitor Information... Manufacturer: **GE or equivalent** Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **Parameter Code: WTF. Required by 40 CFR 60; Subpart GG; S.60.334; oil firing. Request Part 75 NO_x CEM in lieu of WTF monitoring.**	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **Fig 2-2** ☐ Previously Submitted, Date ____
2. Fuel Analysis or Specification (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **Tables 2-4/2-5** ☐ Previously Submitted, Date ____
3. Detailed Description of Control Equipment (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **Section 4.0** ☐ Previously Submitted, Date ____
4. Procedures for Startup and Shutdown (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date ____
   ☒ Not Applicable (construction application)
5. Operation and Maintenance Plan (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date ____
   ☒ Not Applicable
6. Compliance Demonstration Reports/Records
   ☐ Attached, Document ID: ____
   Test Date(s)/Pollutant(s) Tested: ____

   ☐ Previously Submitted, Date: ____
   Test Date(s)/Pollutant(s) Tested: ____

   ☐ To be Submitted, Date (if known): ____
   Test Date(s)/Pollutant(s) Tested: ____

   ☒ Not Applicable

   Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.
7. Other Information Required by Rule or Statute
   ☒ Attached, Document ID: **See PSD Application** ☐ Not Applicable

Additional Requirements for Air Construction Permit Applications

1. Control Technology Review and Analysis (Rules 62-212.400(6) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)) ☐ Attached, Document ID: ____ ☒ Not Applicable	
2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(5)(h)6., F.A.C., and Rule 62-212.500(4)(f), F.A.C.) ☐ Attached, Document ID: ____ ☒ Not Applicable	
3. Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only) ☒ Attached, Document ID: **See PSD Application** ☐ Not Applicable	

Additional Requirements for Title V Air Operation Permit Applications

1. Identification of Applicable Requirements ☐ Attached, Document ID: ____ ☒ Not Applicable	
2. Compliance Assurance Monitoring ☐ Attached, Document ID: ____ ☒ Not Applicable	
3. Alternative Methods of Operation ☐ Attached, Document ID: ____ ☒ Not Applicable	
4. Alternative Modes of Operation (Emissions Trading) ☐ Attached, Document ID: ____ ☒ Not Applicable	
5. Acid Rain Part Application ☐ Certificate of Representation (EPA Form No. 7610-1) ☐ Copy Attached, Document ID: ____ ☐ Acid Rain Part (Form No. 62-210.900(1)(a)) ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date: ____ ☐ Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date: ____ ☐ New Unit Exemption (Form No. 62-210.900(1)(a)2.) ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date: ____ ☐ Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date: ____ ☐ Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date: ____ ☐ Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date: ____ ☒ Not Applicable	

Additional Requirements Comment

III. EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Application - For Title V air operation permitting only, emissions units are classified as regulated, unregulated, or insignificant. If this is an application for Title V air operation permit, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each regulated and unregulated emissions unit addressed in this application for air permit. Some of the subsections comprising the Emissions Unit Information Section of the form are optional for unregulated emissions units. Each such subsection is appropriately marked. Insignificant emissions units are required to be listed at Section II, Subsection C.

Air Construction Permit or FESOP Application - For air construction permitting or federally enforceable state air operation permitting, emissions units are classified as either subject to air permitting or exempt from air permitting. The concept of an "unregulated emissions unit" does not apply. If this is an application for air construction permit or FESOP, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air permitting are required to be listed at Section II, Subsection C.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit Application – Where this application is used to apply for both an air construction permit and a revised/renewal Title V air operation permit, each emissions unit is classified as either subject to air permitting or exempt from air permitting for air construction permitting purposes and as regulated, unregulated, or insignificant for Title V air operation permitting purposes. **The air construction permitting classification must be used to complete the Emissions Unit Information Section of this application for air permit.** A separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air construction permitting and insignificant emissions units are required to be listed at Section II, Subsection C.

If submitting the application form in hard copy, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application must be indicated in the space provided at the top of each page.

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

   ☒ 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.

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).

   ☐ 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. Description of Emissions Unit Addressed in this Section:
   20 MMBtu/hr Gas-Fired Auxiliary Boiler

3. Emissions Unit Identification Number:

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
C			**49**	☒ Yes ☐ No

9. Package Unit: **Auxiliary Boiler**
   Manufacturer: **To be determined** Model Number:

10. Generator Nameplate Rating: MW

11. Emissions Unit Comment:
    20 MMBtu/hr auxiliary boiler for cold startup of GE Frame 7FA combustion turbines

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description:
2. Control Device or Method Code(s):

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:		
2. Maximum Production Rate:		
3. Maximum Heat Input Rate: 20 million Btu/hr		
4. Maximum Incineration Rate:	pounds/hr tons/day	
5. Requested Maximum Operating Schedule:	hours/day weeks/year	days/week 500hours/year
6. Operating Capacity/Schedule Comment:		

C. EMISSION POINT (STACK/VENT) INFORMATION
(Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: **Aux Boiler**		2. Emission Point Type Code: **1**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: **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: **60** feet	7. Exit Diameter: **2.5** feet
8. Exit Temperature: **332**°F	9. Actual Volumetric Flow Rate: **6,485** 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): **414.4** North (km): **3073.9**		14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)
15. Emission Point Comment:		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 1

1. Segment Description (Process/Fuel Type): **Natural Gas**		
2. Source Classification Code (SCC): **2-01-002-01**	3. SCC Units: **Million Cubic Feet**	
4. Maximum Hourly Rate: **0.0195**	5. Maximum Annual Rate: **9.79**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **1,021**
10. Segment Comment: **Based on 1,021 Btu/CF (HHV); 500 hours per year**		

Segment Description and Rate: Segment _ of

1. Segment Description (Process/Fuel Type):		
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:		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM			
SO_2			
NO_x			
CO			
VOC			
SAM			

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **2.0**lb/hour **0.5**tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.10 lb/MMBtu** Reference:	7. Emissions Method Code: **2**
8. Calculation of Emissions: **See Tables A-29.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.5 tons/year**	4. Equivalent Allowable Emissions: **2.0**lb/hour **0.5**tons/year
5. Method of Compliance: **Limitation of operation to less than 500 hours per year**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _ of

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

G. VISIBLE EMISSIONS INFORMATION

Complete if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation 1 of 1

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

Visible Emissions Limitation: Visible Emissions Limitation ____ of ____

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

H. CONTINUOUS MONITOR INFORMATION

Complete if this emissions unit is or would be 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:	

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:	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date ____
2. Fuel Analysis or Specification (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date ____
3. Detailed Description of Control Equipment (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date ____
4. Procedures for Startup and Shutdown (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date ____ ☒ Not Applicable (construction application)
5. Operation and Maintenance Plan (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date ____ ☒ Not Applicable
6. Compliance Demonstration Reports/Records ☐ Attached, Document ID: ____ Test Date(s)/Pollutant(s) Tested: ____ ☐ Previously Submitted, Date: ____ Test Date(s)/Pollutant(s) Tested: ____ ☐ To be Submitted, Date (if known): ____ Test Date(s)/Pollutant(s) Tested: ____ ☒ Not Applicable Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.
7. Other Information Required by Rule or Statute ☒ Attached, Document ID: **See PSD Application** ☐ Not Applicable

Additional Requirements for Air Construction Permit Applications

1. Control Technology Review and Analysis (Rules 62-212.400(6) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)) ☐ Attached, Document ID: ____ ☒ Not Applicable
2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(5)(h)6., F.A.C., and Rule 62-212.500(4)(f), F.A.C.) ☐ Attached, Document ID: ____ ☒ Not Applicable
3. Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only) ☒ Attached, Document ID: **See PSD Application** ☐ Not Applicable

Additional Requirements for Title V Air Operation Permit Applications

1. Identification of Applicable Requirements ☐ Attached, Document ID: ____ ☒ Not Applicable
2. Compliance Assurance Monitoring ☐ Attached, Document ID: ____ ☒ Not Applicable
3. Alternative Methods of Operation ☐ Attached, Document ID: ____ ☒ Not Applicable
4. Alternative Modes of Operation (Emissions Trading) ☐ Attached, Document ID: ____ ☒ Not Applicable
5. Acid Rain Part Application ☐ Certificate of Representation (EPA Form No. 7610-1) ☐ Copy Attached, Document ID: ____ ☐ Acid Rain Part (Form No. 62-210.900(1)(a)) ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date: ____ ☐ Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date: ____ ☐ New Unit Exemption (Form No. 62-210.900(1)(a)2.) ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date: ____ ☐ Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date: ____ ☐ Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date: ____ ☐ Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date: ____ ☒ Not Applicable

Additional Requirements Comment

ATTACHMENT 2

Revised Emission Tables

Table 1 Comparison of Stack, Operating, and Emission Data- GE Frame 7FA vs SW 501F, Combined Cycle Operation
Natural Gas- Firing

Parameter	Basis/ Units		GE Frame 7FA			SW 501F		
Stack Data	Height	ft	125	125	125	125	125	125
	Diameter	ft	18.0	18.0	18.0	19.0	19.0	19.0
Ambient Conditions	Temperature	°F	20 °F	59 °F	95 °F	20 °F	59 °F	90°F
Operating Data	Load	%	100	100	100	100	100	100
	HIR (HHV)	MMBtu/hr	1,941	1,806	1,644	2,012	1,830	1,705
	Temperature	°F	203	202	201	190	190	190
	Velocity	ft/sec	72.8	67.9	62.2	63.3	59.2	55.4
PM/PM_{10}	lb/hr		10.1	10.0	9.9	8.46	7.86	7.18
	Basis [a]		Dry filterables	Dry filterables	Dry filterables	Dry filterables	Dry filterables	Dry filterables
SO_2	lb/hr		5.43	5.05	4.60	5.63	5.12	4.77
	gr sulfur/100 scf		1	1	1	1	1	1
NO_x	lb/hr		17.7	16.5	15.0	18.0	16.5	15.1
	ppmvd @15% O2		2.5	2.5	2.5	2.5	2.5	2.5
CO	lb/hr		32.1	29.7	26.8	46	42	37
	ppmvd		9.0	9.0	9.0	12.4	12.2	12.4
	ppmvd @15% O2		7.5	7.4	7.4	10.0	10.0	10.0
VOC (as methane)	lb/hr		3.09	2.88	2.65	4.65	4.35	3.75
	ppmvw		1.4	1.4	1.4	2.4	2.4	2.5
	ppmvd @15% O2		1.3	1.3	1.3	1.8	1.8	1.8
Sulfuric Acid Mist	lb/hr		0.83	0.77	0.70	0.86	0.78	0.73
	% SO2 from CT		10	10	10	10	10	10
Operating Data	Load	%	75	75	75	80	80	80
	HIR (HHV)	MMBtu/hr	1,594	1,473	1,361	1,537	1,534	1,419
	Temperature	°F	203	204	205	190	190	190
	Velocity	ft/sec	54.9	54.8	51.8	57.0	54.0	51.3
PM/PM_{10}	lb/hr		9.9	9.8	9.8	7.49	7.09	6.32
	Basis [a]		Dry filterables	Dry filterables	Dry filterables	Dry filterables	Dry filterables	Dry filterables
SO_2	lb/hr		4.46	4.12	3.81	4.30	4.29	3.97
	gr sulfur/100 scf		1	1	1	1	1	1
NO_x	lb/hr		14.4	13.3	12.2	14.7	13.7	12.6
	ppmvd @15% O2		2.5	2.5	2.5	2.5	2.5	2.5
CO	lb/hr		24.1	23.9	22.2	38	35	33
	ppmvd		9.0	9.0	9.0	11.2	11.1	10.9
	ppmvd @15% O2		6.9	7.4	7.5	10.0	10.0	10.0
VOC (as methane)	lb/hr		2.33	2.32	2.19	4.9	4.6	4.2
	ppmvw		1.4	1.4	1.4	2.8	2.8	2.8
	ppmvd @15% O2		1.2	1.3	1.3	2.3	2.3	2.3
Sulfuric Acid Mist	lb/hr		0.68	0.63	0.58	0.66	0.66	0.61
	% SO2 from CT		10	10	10	10	10	10
Operating Data	Load	%	50	50	50	60	60	60
	HIR (HHV)	MMBtu/hr	1,257	1,179	1,085	1,347	1,280	1,178
	Temperature	°F	175	178	182	190	190	190
	Velocity	ft/sec	44.4	43.5	42.1	46.0	44.0	42.3
PM/PM_{10}	lb/hr		9.7	9.7	9.6	6.08	5.84	5.48
	Basis [a]		Dry filterables	Dry filterables	Dry filterables	Dry filterables	Dry filterables	Dry filterables
SO_2	lb/hr		3.52	3.30	3.03	3.77	3.58	3.30
	gr sulfur/100 scf		1	1	1	1	1	1
NO_x	lb/hr		11.2	10.5	9.7	12.0	11.4	10.5
	ppmvd @15% O2		2.5	2.5	2.5	2.5	2.5	2.5
CO	lb/hr		20.4	19.9	18.8	154	146	134
	ppmvd		9.0	9.0	9.0	57	57	55
	ppmvd @15% O2		7.5	7.8	8.0	50	50	50
VOC (as methane)	lb/hr		1.96	1.92	1.84	5.3	5	4.6
	ppmvw		1.4	1.4	1.4	3.7	3.7	3.6
	ppmvd @15% O2		1.3	1.3	1.4	3.0	3.0	3.0
Sulfuric Acid Mist	lb/hr		0.54	0.51	0.46	0.58	0.55	0.50
	% SO2 from CT		10	10	10	10	10	10

[a] PM10 includes conversion of SO2 to SO3 in the SCR to form ammonium sulfate

Table 2. Comparison of Stack, Operating, and Emission Data- GE Frame 7FA vs SW 501F, Combined Cycle Operation
Distillate Oil- Firing

Parameter	Basis/ Units		GE Frame 7FA			SW 501F		
Stack Data	Height	ft	125	125	125	125	125	125
	Diameter	ft	18.0	18.0	18.0	19.0	19.0	19.0
Ambient Conditions	Temperature	°F	20 °F	59 °F	95 °F	20 °F	59 °F	105 °F
Operating Data	Load	%	100	100	100	100	100	100
	HIR (HHV)	MMBtu/hr	2,086	1,962	1,769	2,100	1,932	1,707
	Temperature	°F	297	295	294	270	270	270
	Velocity	ft/sec	86.2	80.0	72.7	69.4	67.0	60.0
PM/PM_{10}	lb/hr		39.1	37.8	35.7	64.8	59.6	52.5
	Basis *		Dry filterables	Dry filterables	Dry filterables	Dry filterables	Dry filterables	Dry filterables
SO_2	lb/hr		109.2	102.8	92.6	105.6	97.1	85.8
	Sulfur content	%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%
NO_x	lb/hr		82.4	76.7	69.9	77.0	73.0	64.4
	ppmvd @15% O2		10	10	10	10	10	10
CO	lb/hr		71.4	66.0	59.0	112	106	91
	ppmvd		20	20	20	30	30	30
	ppmvd @15% O2		14.2	14.1	13.9	22.2	22.4	22.2
VOC (as methane)	lb/hr		8.01	7.45	6.79	22	21	19
	ppmvw		3.5	3.5	3.5	10	10	10
	ppmvd @15% O2		2.8	2.8	2.8	7.9	8.1	8.1
Sulfuric Acid Mist	lb/hr		16.7	15.7	14.2	16.2	14.9	13.1
	% SO2 from CT		10	10	10	10	10	10
Operating Data	Load	%	75	75	75	80	80	80
	HIR (HHV)	MMBtu/hr	1,594	1,473	1,361	1,644	1,524	1,364
	Temperature	°F	271	274	278	270	270	270
	Velocity	ft/sec	61.5	59.9	58.1	68.9	65.2	58.5
PM/PM_{10}	lb/hr		35.1	34.0	32.4	52.36	48.57	44.35
	Basis *		Dry filterables	Dry filterables	Dry filterables	Dry filterables	Dry filterables	Dry filterables
SO_2	lb/hr		89.4	84.0	76.3	85.6	79.4	71.0
	Sulfur content		0.05%	0.05%	0.05%	0.05%	0.05%	0.05%
NO_x	lb/hr		66.8	62.7	57.0	64.4	60.0	53.3
	ppmvd @15% O2		10	10	10	10	10	10
CO	lb/hr		52.2	50.6	48.3	111	103	89
	ppmvd		20	20	20	30	30	30
	ppmvd @15% O2		12.8	13.2	13.9	26.6	26.9	26.6
VOC (as methane)	lb/hr		5.91	5.74	5.53	21	22	19
	ppmvw		3.5	3.5	3.5	10	10	10
	ppmvd @15% O2		2.5	2.6	2.8	9.4	9.6	9.6
Sulfuric Acid Mist	lb/hr		13.7	12.9	11.7	13.1	12.2	10.9
	% SO2 from CT		10	10	10	10	10	10
Operating Data	Load	%	50	50	50	65	65	65
	HIR (HHV)	MMBtu/hr	1,257	1,179	1,085	1,385	1,296	1,182
	Temperature	°F	256	259	268	270	270	270
	Velocity	ft/sec	50.1	49.6	48.3	63.1	59.8	55.3
PM/PM_{10}	lb/hr		31.0	30.2	29.1	43.5	40.9	37.2
	Basis *		Dry filterables	Dry filterables	Dry filterables	Dry filterables	Dry filterables	Dry filterables
SO_2	lb/hr		69.1	65.5	59.6	72.1	67.5	61.5
	Sulfur content		0.05%	0.05%	0.05%	0.05%	0.05%	0.05%
NO_x	lb/hr		51.2	48.5	44.1	54.1	50.6	46.2
	ppmvd @15% O2		10	10	10	10	10	10
CO	lb/hr		44.2	43.4	41.3	101	94	86
	ppmvd		20	20	20	30	30	30
	ppmvd @15% O2		14.2	14.7	15.4	29.3	29.5	29.2
VOC (as methane)	lb/hr		4.92	4.85	4.66	20	19	19
	ppmvw		3.5	3.5	3.5	10	10	10
	ppmvd @15% O2		2.8	2.9	3.0	10.3	10.4	10.4
Sulfuric Acid Mist	lb/hr		10.6	10.0	9.1	11.0	10.3	9.4
	% SO2 from CT		10	10	10	10	10	10

* PM10 includes conversion of SO2 to SO3 in the SCR to form ammonium sulfate

Table A-1. Design Information and Stack Parameters for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 100% Load

Parameter	CT Only Turbine Inlet Temperature 20 °F	 59 °F	 95 °F
Combustion Turbine Performance			
Power output (MW)	193.1	173.8	154.8
Heat rate (Btu/kWh, LHV)	9,055	9,360	9,570
(Btu/kWh, HHV)	10,051	10,390	10,623
Heat Input (MMBtu/hr, LHV)- provided	1727.7	1607.1	1463.3
Heat Input (MMBtu/hr, LHV)- with margin	1,749	1,627	1,481
(MMBtu/hr, HHV)	1,941	1,806	1,644
Evaporative Cooler status/efficiency (%)	Off	Off	Off
Relative Humidity (%)	80	60	50
Fuel heating value (Btu/lb, LHV)	21,039	21,039	21,039
(Btu/lb, HHV)	23,353	23,353	23,353
(HHV/LHV)	1.110	1.110	1.110
CT Exhaust Flow			
Mass Flow (lb/hr)- with margin	3,929,264	3,650,916	3,333,093
- provided	3,882,000	3,607,000	3,293,000
Temperature (°F)	1,074	1,113	1,154
Moisture (% Vol.)	7.55	8.37	9.88
Oxygen (% Vol.)	12.75	12.57	12.34
Molecular Weight	28.48	28.38	28.22
CT 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)	3,929,264	3,650,916	3,333,093
Temperature (°F)	1,074	1,113	1,154
Molecular weight	28.48	28.38	28.22
Volume flow (acfm)- calculated	2,574,253	2,461,202	2,318,987
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)	1,749	1,627	1,481
Heat content (Btu/lb, LHV)	21,039	21,039	21,039
Fuel usage (lb/hr)- calculated	83,119	77,317	70,399
Heat content (Btu/cf, LHV)- assumed	920	920	920
Fuel density (lb/ft^3)	0.0437	0.0437	0.0437
Fuel usage (cf/hr)- calculated	1,900,799	1,768,116	1,609,909
HRSG Stack			
HRSG - Stack Height (ft)	125	125	125
Diameter (ft)	18	18	18
HRSG Stack Flow Conditions			
Velocity (ft/sec) = Volume flow (acfm) / [((diameter)^2 /4) x 3.14159] / 60 sec/min			
Mass flow (lb/hr)	3,929,264	3,650,916	3,333,093
HRSG Stack Temperature (°F)	203	202	201
Molecular weight	28.48	28.38	28.22
Volume flow (acfm)	1,112,097	1,036,271	949,721
Diameter (ft)	18	18	18
Velocity (ft/sec)- calculated	72.8	67.9	62.2

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, 2004 - CT Performance Data

Table A-2. Maximum Emissions for Criteria Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 100% Load

Parameter	CT Only Turbine Inlet Temperature 20 °F	59 °F	95 °F
Particulate from CT and SCR			
Total PM_{10} = PM_{10} (front half) + PM_{10} ($(NH_4)_2SO_4$) from SCR only			
a. PM_{10} (front half)			
CT (lb/hr)- provided	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	5.4	5.1	4.6
Conversion (%) from SO_2 to SO_3	10	10	10
MW SO_3/ SO_2 (80/64)	1.3	1.3	1.3
Conversion (%) from SO_3 to $(NH_4)_2(SO_4)$	100	100	100
MW $(NH_4)_2$ SO_4/ SO_3 (132/80)	1.7	1.7	1.7
SCR Particulate (lb/hr)- calculated	1.12	1.04	0.95
Total CT emission rate (lb/hr) [a]	9.0	9.0	9.0
Total HRSG emission rate (lb/hr) [a + b]	10.1	10.0	9.9
(lb/mmBtu, HHV)	0.0052	0.0056	0.0061
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)	1,900,799	1,768,116	1,609,909
Sulfur content (grains/ 100 cf)	1	1	1
lb SO_2 /lb S (64/32)	2	2	2
HRSG emission rate (lb/hr)	5.4	5.1	4.6
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 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, ppmvd @15% O_2	9	9	9
Moisture (%)	7.55	8.37	9.88
Oxygen (%)	12.75	12.57	12.34
CT Flow (acfm)	2,574,253	2,461,202	2,318,987
CT Exhaust Temperature (°F)	1,074	1,113	1,154
CT Emission rate (lb/hr)	63.6	59.4	53.8
(lb/hr)- provided	63.0	59.0	53.0
HRSG Stack emission rate (ppmvd @ 15% O_2)	2.5	2.5	2.5
(lb/hr)	17.7	16.5	15.0
(lb/MMBtu)	0.0091	0.0091	0.0091
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
Basis, ppmvd @ 15% O2 - calculated	7.47	7.39	7.37
Moisture (%)	7.55	8.37	9.88
Oxygen (%)	12.75	12.57	12.34
CT Flow (acfm)	2,574,253	2,461,202	2,318,987
CT Exhaust Temperature (°F)	1,074	1,113	1,154
HRSG Emission rate (lb/hr)	32.1	29.7	26.8
(lb/hr)- provided	32.0	29.0	26.0

Table A-2. Maximum Emissions for Criteria Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 100% Load

Parameter	CT Only Turbine Inlet Temperature 20 °F	 59 °F	 95 °F
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	1.4	1.4	1.4
Basis, ppmvd @ 15% O2 - calculated	1.3	1.26	1.3
Moisture (%)	7.55	8.37	9.88
Oxygen (%) wet	12.75	12.57	12.34
CT Flow (acfm)	2,574,253	2,461,202	2,318,987
CT Exhaust Temperature (°F)	1,074	1,113	1,154
HRSG Emission rate (lb/hr)	3.09	2.88	2.65
(lb/hr)- provided	3.00	2.80	2.60
Sulfuric Acid Mist			
Sulfuric Acid Mist = SO_2 emission rate (lb/hr) x conversion rate of SO_2 to H_2SO_4 (%) x MW H_2SO_4 /MW SO_2 (98/64)			
CT SO_2 emission rate (lb/hr) - provided	5.4	5.1	4.6
CT Conversion to H_2SO_4 (% by weight) - provided	10	10	10
MW H2SO4 /MW SO2 (98/64)	1.53	1.53	1.53
HRSG Emission rate (lb/hr)	0.83	0.77	0.70
Lead			
Lead (lb/hr) = NA			
Emission Rate Basis	NA	NA	NA
Emission rate (lb/hr)	NA	NA	NA

Note: ppmvd= parts per million, volume dry; O_2= oxygen.

Source: GE, 2004 - CT Performance Data

Table A-3. Maximum Emissions for Other Regulated PSD Pollutants forthe Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 100% Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
Hours of Operation	8,760	8,760	8,760
Heat Input Rate (MMBtu/hr), HHV- CT	1,941	1,806	1,644
Total	1,941	1,806	1,644
2,3,7,8 TCDD Equivalents (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	1.20E-06	1.20E-06	1.20E-06
Heat Input Rate (MMBtu/hr)	1,941	1,806	1,644
Emission Rate (lb/hr)	2.33E-09	2.17E-09	1.97E-09
(TPY)	1.02E-08	9.49E-09	8.64E-09
Beryllium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,941	1,806	1,644
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Fluoride (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,941	1,806	1,644
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Mercury (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu [c]	8.00E-04	8.00E-04	8.00E-04
Heat Input Rate (MMBtu/hr), HHV- CT	1,941	1,806	1,644
Emission Rate (lb/hr)	1.55E-06	1.44E-06	1.32E-06
(TPY)	6.80E-06	6.33E-06	5.76E-06

Source: Electric Power Research Institute (EPRI), Electric Utility Trace Substances Report, 1994 (Table B-12).
Emission factors for metals are questionable and not used.

Note: No emission factors for hydrogen chloride (HCl) from natural gas-firing.

Table A-4. Maximum Emissions for Hazardous Air Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 100% Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
Hours of Operation	8,760	8,760	8,760
Heat Input Rate (MMBtu/hr), HHV- CT	1,941	1,806	1,644
Total	1,941	1,806	1,644
Antimony (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,941	1,806	1,644
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Benzene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	8.00E-01	8.00E-01	8.00E-01
Heat Input Rate (MMBtu/hr)	1,941	1,806	1,644
Emission Rate (lb/hr)	1.55E-03	1.44E-03	1.32E-03
(TPY)	6.80E-03	6.33E-03	5.76E-03
Cadmium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,941	1,806	1,644
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Chromium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,941	1,806	1,644
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Cobalt (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,941	1,806	1,644
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Manganese (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,941	1,806	1,644
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Nickel (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,941	1,806	1,644
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Phosphorous (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,941	1,806	1,644
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00

Table A-4. Maximum Emissions for Hazardous Air Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 100% Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
Selenium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,941	1,806	1,644
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Toluene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	1.00E+01	1.00E+01	1.00E+01
Heat Input Rate (MMBtu/hr)	1,941	1,806	1,644
Emission Rate (lb/hr)	1.94E-02	1.81E-02	1.64E-02
(TPY)	8.50E-02	7.91E-02	7.20E-02

Source: Electric Power Research Institute (EPRI), Electric Utility Trace Substances Report, 1994 (Table B-12).
Emission factors for metals are questionable and not used.

Table A-5. Design Information and Stack Parameters for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 75% Load

Parameter	Turbine Inlet Temperature		
	20 °F	59 °F	95 °F
Combustion Turbine Performance			
Power output (MW)	144.8	132.2	116.1
Heat rate (Btu/kWh, LHV)	9,915	10,040	10,560
(Btu/kWh, HHV)	11,006	11,144	11,722
Heat Input (MMBtu/hr, LHV)- provided	1,419	1,311	1,211
Heat Input (MMBtu/hr, LHV)- with margin	1,436	1,327	1,226
(MMBtu/hr, HHV)	1,594	1,473	1,361
Evaporative Cooler status/efficiency (%)	Off	Off	Off
Relative Humidity (%)	80	60	50
Fuel heating value (Btu/lb, LHV)	21,039	21,039	21,039
(Btu/lb, HHV)	23,353	23,353	23,353
(HHV/LHV)	1.110	1.110	1.110
CT Exhaust Flow			
Mass Flow (lb/hr)- with margin	2,956,564	2,941,381	2,762,226
- provided	2,921,000	2,906,000	2,729,000
Temperature (°F)	1,200	1,159	1,190
Moisture (% Vol.)	8.13	8.26	9.8
Oxygen (% Vol.)	12.11	12.60	12.43
Molecular Weight	28.44	28.41	28.22
CT 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)	2,956,564	2,941,381	2,762,226
Temperature (°F)	1,200	1,159	1,190
Molecular weight	28.44	28.41	28.22
Volume flow (acfm)- calculated	2,099,089	2,039,302	1,964,313
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)	1,436	1,327	1,226
Heat content (Btu/lb, LHV)	21,039	21,039	21,039
Fuel usage (lb/hr)- calculated	68,258	63,081	58,270
Heat content (Btu/cf, LHV)- assumed	920	920	920
Fuel density (lb/ft^3)	0.0437	0.0437	0.0437
Fuel usage (cf/hr)- calculated	1,560,950	1,442,570	1,332,551
HRSG Stack			
HRSG - Stack Height (ft)	125	125	125
Diameter (ft)	18	18	18
HRSG Stack Flow Conditions			
Velocity (ft/sec) = Volume flow (acfm) / [((diameter)^2 /4) x 3.14159] / 60 sec/min			
Mass flow (lb/hr)	2,956,564	2,941,381	2,762,226
HRSG Stack Temperature (°F)	203	204	205
Molecular weight	28.44	28.41	28.22
CT volume flow (acfm)	837,992	836,001	791,320
Diameter (ft)	18	18	18
Velocity (ft/sec)- calculated	54.9	54.8	51.8

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, 2004 - CT Performance Data

Table A-6. Maximum Emissions for Criteria Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 75% Load

Parameter	CT Only Turbine Inlet Temperature 20 °F	 59 °F	 95 °F
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)			
CT (lb/hr)- provided	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	4.5	4.1	3.8
Conversion (%) from SO_2 to SO_3	9.8	9.8	9.8
MW SO_3/ SO_2 (80/64)	1.3	1.3	1.3
Conversion (%) from SO_3 to $(NH_4)_2(SO_4)$	100	100	100
MW $(NH_4)_2$ SO_4/ SO_3 (132/80)	1.7	1.7	1.7
SCR Particulate (lb/hr)- calculated	0.90	0.83	0.77
Total CT emission rate (lb/hr) [a]	9.0	9.0	9.0
Total HRSG emission rate (lb/hr) [a + b]	9.9	9.8	9.8
(lb/mmBtu, HHV)	0.0062	0.0067	0.0072
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)	1,560,950	1,442,570	1,332,551
Sulfur content (grains/ 100 cf)	1	1	1
lb SO_2 /lb S (64/32)	2	2	2
HRSG emission rate (lb/hr)	4.5	4.1	3.8
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 flc 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, ppmvd @15% O_2	9	9	9
Moisture (%)	8.13	8.26	9.8
Oxygen (%)	12.11	12.60	12.43
CT Flow (acfm)	2,099,089	2,039,302	1,964,313
CT Exhaust Temperature (°F)	1,200	1,159	1,190
CT Emission rate (lb/hr)	51.7	47.8	44.1
(lb/hr)- provided	51.0	47.0	44.0
HRSG Stack emission rate (ppmvd @ 15% O_2)	2.5	2.5	2.5
(lb/hr)	14.4	13.3	12.2
(lb/MMBtu)	0.0090	0.0090	0.0090
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
Basis, ppmvd @ 15% O2 - calculated	6.88	7.41	7.46
Moisture (%)	8.13	8.26	9.80
Oxygen (%)	12.11	12.60	12.43
CT Flow (acfm)	2,099,089	2,039,302	1,964,313
CT Exhaust Temperature (°F)	1,200	1,159	1,190
HRSG Emission rate (lb/hr)	24.1	23.9	22.2
(lb/hr)- provided	24.0	24.0	22.0

Table A-6. Maximum Emissions for Criteria Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 75% Load

Parameter	CT Only Turbine Inlet Temperature 20 °F	 59 °F	 95 °F
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	1.4	1.4	1.4
Basis, ppmvd @ 15% O2 - calculated	1.2	1.3	1.3
Moisture (%)	8.13	8.26	9.80
Oxygen (%) wet	12.11	12.60	12.43
CT Flow (acfm)	2,099,089	2,039,302	1,964,313
CT Exhaust Temperature (°F)	1,200	1,159	1,190
HRSG Emission rate (lb/hr)	2.33	2.32	2.19
(lb/hr)- provided	2.4	2.2	2.2
Sulfuric Acid Mist			
Sulfuric Acid Mist = SO_2 emission rate (lb/hr) x conversion rate of SO_2 to H_2SO_4 (%) x MW H_2SO_4 /MW SO_2 (98/64)			
CT SO_2 emission rate (lb/hr) - provided	4.5	4.1	3.8
CT Conversion to H_2SO_4 (% by weight) - provided	10	10	10
MW H2SO4 /MW SO2 (98/64)	1.53	1.53	1.53
HRSG Emission rate (lb/hr)	0.68	0.63	0.58
Lead			
Lead (lb/hr) = NA			
Emission Rate Basis	NA	NA	NA
Emission rate (lb/hr)	NA	NA	NA

Note: ppmvd= parts per million, volume dry; O_2= oxygen.

Source: GE, 2004 - CT Performance Data; Golder Associates, 2004

Table A-7. Maximum Emissions for Other Regulated PSD Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 75% Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
Hours of Operation	8,760	8,760	8,760
Heat Input Rate (MMBtu/hr), HHV- CT	1,594	1,473	1,361
Total	1,594	1,473	1,361
2,3,7,8 TCDD Equivalents (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	1.20E-06	1.20E-06	1.20E-06
Heat Input Rate (MMBtu/hr)	1,594	1,473	1,361
Emission Rate (lb/hr)	1.91E-09	1.77E-09	1.63E-09
(TPY)	8.38E-09	7.74E-09	7.15E-09
Beryllium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,594	1,473	1,361
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Fluoride (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,594	1,473	1,361
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Mercury (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu [c]	8.00E-04	8.00E-04	8.00E-04
Heat Input Rate (MMBtu/hr), HHV- CT	1,594	1,473	1,361
Emission Rate (lb/hr)	1.28E-06	1.18E-06	1.09E-06
(TPY)	5.59E-06	5.16E-06	4.77E-06

Source: Electric Power Research Institute (EPRI), Electric Utility Trace Substances Report, 1994 (Table B-12).
Emission factors for metals are questionable and not used.

Note: No emission factors for hydrogen chloride (HCl) from natural gas-firing.

Table A-8. Maximum Emissions for Hazardous Air Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 75% Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
Hours of Operation	8,760	8,760	8,760
Heat Input Rate (MMBtu/hr), HHV- CT	1,594	1,473	1,361
Total	1,594	1,473	1,361
Antimony (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,594	1,473	1,361
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Benzene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	8.00E-01	8.00E-01	8.00E-01
Heat Input Rate (MMBtu/hr)	1,594	1,473	1,361
Emission Rate (lb/hr)	1.28E-03	1.18E-03	1.09E-03
(TPY)	5.59E-03	5.16E-03	4.77E-03
Cadmium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,594	1,473	1,361
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Chromium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,594	1,473	1,361
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Cobalt (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,594	1,473	1,361
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Manganese (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,594	1,473	1,361
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Nickel (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,594	1,473	1,361
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Phosphorous (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,594	1,473	1,361
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00

Table A-8. Maximum Emissions for Hazardous Air Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 75% Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
Selenium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,594	1,473	1,361
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Toluene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	1.00E+01	1.00E+01	1.00E+01
Heat Input Rate (MMBtu/hr)	1,594	1,473	1,361
Emission Rate (lb/hr)	1.59E-02	1.47E-02	1.36E-02
(TPY)	6.98E-02	6.45E-02	5.96E-02

Source: Electric Power Research Institute (EPRI), Electric Utility Trace Substances Report, 1994 (Table B-12).
Emission factors for metals are questionable and not used.

Table A-9. Design Information and Stack Parameters for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 50% Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
Combustion Turbine Performance			
Power output (MW)	96.6	88.2	77.4
Heat rate (Btu/kWh, LHV)	11,730	12,050	12,620
(Btu/kWh, HHV)	13,020	13,376	14,008
Heat Input (MMBtu/hr, LHV)- provided	1,119	1,050	965
Heat Input (MMBtu/hr, LHV)- with margin	1,133	1,062	977
(MMBtu/hr, HHV)	1,257	1,179	1,085
Evaporative Cooler status/efficiency (%)	Off	Off	Off
Relative Humidity (%)	80	60	50
Fuel heating value (Btu/lb, LHV)	21,039	21,039	21,039
(Btu/lb, HHV)	23,353	23,353	23,353
(HHV/LHV)	1.110	1.110	1.110
CT Exhaust Flow			
Mass Flow (lb/hr)- with margin	2,498,048	2,433,269	2,325,978
- provided	2,468,000	2,404,000	2,298,000
Temperature (°F)	1,200	1,200	1,200
Moisture (% Vol.)	7.54	7.96	9.37
Oxygen (% Vol.)	12.77	12.94	12.92
Molecular Weight	28.48	28.42	28.25
CT 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)	2,498,048	2,433,269	2,325,978
Temperature (°F)	1,200	1,200	1,200
Molecular weight	28.48	28.42	28.25
Volume flow (acfm)- calculated	1,770,983	1,728,651	1,662,592
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)	1,133	1,062	977
Heat content (Btu/lb, LHV)	21,039	21,039	21,039
Fuel usage (lb/hr)- calculated	53,834	50,496	46,445
Heat content (Btu/cf, LHV)- assumed	920	920	920
Fuel density (lb/ft^3)	0.0437	0.0437	0.0437
Fuel usage (cf/hr)- calculated	1,231,113	1,154,760	1,062,124
HRSG Stack			
HRSG - Stack Height (ft)	125	125	125
Diameter (ft)	18	18	18
HRSG Stack Flow Conditions			
Velocity (ft/sec) = Volume flow (acfm) / [((diameter)^2 /4) x 3.14159] / 60 sec/min			
Mass flow (lb/hr)	2,498,048	2,433,269	2,325,978
HRSG Stack Temperature (°F)	175	178	182
Molecular weight	28.48	28.42	28.25
CT volume flow (acfm)	677,774	663,865	643,203
Diameter (ft)	18	18	18
Velocity (ft/sec)- calculated	44.4	43.5	42.1

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, 2004 - CT Performance Data; Golder Associates, 2004

Table A-10. Maximum Emissions for Criteria Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 50% Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
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)			
CT (lb/hr)- provided	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	3.5	3.3	3.0
Conversion (%) from SO_2 to SO_3	9.8	9.8	9.8
MW SO_3/ SO_2 (80/64)	1.3	1.3	1.3
Conversion (%) from SO_3 to $(NH_4)_2(SO_4)$	100	100	100
MW $(NH_4)_2SO_4$/ SO_3 (132/80)	1.7	1.7	1.7
SCR Particulate (lb/hr)- calculated	0.71	0.67	0.61
CT emission rate (lb/hr) [a]	9.0	9.0	9.0
Total emission rate (lb/hr) [a + b]	9.7	9.7	9.6
(lb/mmBtu, HHV)	0.0077	0.0082	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)	1,231,113	1,154,760	1,062,124
Sulfur content (grains/ 100 cf)	1	1	1
lb SO_2 /lb S (64/32)	2	2	2
HRSG emission rate (lb/hr)	3.5	3.3	3.0
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 flov 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, ppmvd @15% O_2	9	9	9
Moisture (%)	7.54	7.96	9.37
Oxygen (%)	12.77	12.94	12.92
CT Flow (acfm)	1,770,983	1,728,651	1,662,592
CT Exhaust Temperature (°F)	1,200	1,200	1,200
CT Emission rate (lb/hr)	40.3	37.8	34.8
(lb/hr)- provided	40.0	37.0	34.0
HRSG Stack emission rate (ppmvd @ 15% O_2)	2.5	2.5	2.5
(lb/hr)	11.2	10.5	9.7
(lb/MMBtu)	0.0089	0.0089	0.0089
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
Basis, ppmvd @ 15% O2 - calculated	7.49	7.76	7.99
Moisture (%)	7.54	7.96	9.37
Oxygen (%)	12.77	12.94	12.92
CT Flow (acfm)	1,770,983	1,728,651	1,662,592
CT Exhaust Temperature (°F)	1,200	1,200	1,200
HRSG Emission rate (lb/hr)	20.4	19.9	18.8
(lb/hr)- provided	20	20	19

Table A-10. Maximum Emissions for Criteria Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 50% Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
<u>Volatile Organic Compounds</u>			
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	1.4	1.4	1.4
Basis, ppmvd @ 15% O2 - calculated	1.3	1.3	1.4
Moisture (%)	7.54	7.96	9.37
Oxygen (%) wet	12.77	12.94	12.92
CT Flow (acfm)	1,770,983	1,728,651	1,662,592
CT Exhaust Temperature (°F)	1,200	1,200	1,200
HRSG Emission rate (lb/hr)	1.96	1.92	1.84
(lb/hr)- provided	2.00	1.80	1.80
<u>Sulfuric Acid Mist</u>			
Sulfuric Acid Mist = SO_2 emission rate (lb/hr) x conversion rate of SO_2 to H_2SO_4 (%) x MW H_2SO_4 /MW SO_2 (98/64)			
CT SO_2 emission rate (lb/hr) - provided	3.5	3.3	3.0
CT Conversion to H_2SO_4 (% by weight) - provided	10	10	10
MW H2SO4 /MW SO2 (98/64)	1.53	1.53	1.53
HRSG Emission rate (lb/hr)	0.54	0.51	0.46
<u>Lead</u>			
Lead (lb/hr) = NA			
Emission Rate Basis	NA	NA	NA
Emission rate (lb/hr)	NA	NA	NA

Note: ppmvd= parts per million, volume dry; O_2= oxygen.

Source: GE, 2004 - CT Performance Data; Golder Associates, 2004

Table A-11. Maximum Emissions for Other Regulated PSD Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 50% Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
Hours of Operation	8,760	8,760	8,760
Heat Input Rate (MMBtu/hr), HHV- CT	1,257	1,179	1,085
Total	1,257	1,179	1,085
2,3,7,8 TCDD Equivalents (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	1.20E-06	1.20E-06	1.20E-06
Heat Input Rate (MMBtu/hr)	1,257	1,179	1,085
Emission Rate (lb/hr)	1.51E-09	1.42E-09	1.30E-09
(TPY)	6.61E-09	6.20E-09	5.70E-09
Beryllium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,257	1,179	1,085
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Fluoride (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,257	1,179	1,085
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Mercury (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu [c]	8.00E-04	8.00E-04	8.00E-04
Heat Input Rate (MMBtu/hr), HHV- CT	1,257	1,179	1,085
Emission Rate (lb/hr)	1.01E-06	9.43E-07	8.68E-07
(TPY)	4.41E-06	4.13E-06	3.80E-06

Source: Electric Power Research Institute (EPRI), Electric Utility Trace Substances Report, 1994 (Table B-12).
Emission factors for metals are questionable and not used.

Note: No emission factors for hydrogen chloride (HCl) from natural gas-firing.

Table A-12. Maximum Emissions for Hazardous Air Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 50% Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
Hours of Operation	8,760	8,760	8,760
Heat Input Rate (MMBtu/hr), HHV- CT	1,257	1,179	1,085
Total	1,257	1,179	1,085
Antimony (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,257	1,179	1,085
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Benzene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	8.00E-01	8.00E-01	8.00E-01
Heat Input Rate (MMBtu/hr)	1,257	1,179	1,085
Emission Rate (lb/hr)	1.01E-03	9.43E-04	8.68E-04
(TPY)	4.41E-03	4.13E-03	3.80E-03
Cadmium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,257	1,179	1,085
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Chromium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,257	1,179	1,085
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Cobalt (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,257	1,179	1,085
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Manganese (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,257	1,179	1,085
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Nickel (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,257	1,179	1,085
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Phosphorous (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,257	1,179	1,085
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00

Table A-12. Maximum Emissions for Hazardous Air Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 50% Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
Selenium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,257	1,179	1,085
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Toluene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	1.00E+01	1.00E+01	1.00E+01
Heat Input Rate (MMBtu/hr)	1,257	1,179	1,085
Emission Rate (lb/hr)	1.26E-02	1.18E-02	1.08E-02
(TPY)	5.51E-02	5.17E-02	4.75E-02

Source: Electric Power Research Institute (EPRI), Electric Utility Trace Substances Report, 1994 (Table B-12).
Emission factors for metals are questionable and not used.

Table A-13. Design Information and Stack Parameters for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, Base Load

Parameter	Turbine Inlet Temperature		
	20 °F	59 °F	95 °F
Combustion Turbine Performance			
Power output (MW)	193.5	181.5	158.9
Heat rate (Btu/kWh, LHV)	10,050	10,080	10,380
(Btu/kWh, HHV)	10,778	10,810	11,132
Heat Input (MMBtu/hr, LHV)- provided	1,945	1,830	1,649
Heat Input (MMBtu/hr, LHV)- with margin	1,945	1,830	1,649
(MMBtu/hr, HHV)	2,086	1,962	1,769
Relative Humidity (%)	60	60	60
Fuel heating value (Btu/lb, LHV)	17,803	17,803	17,803
(Btu/lb, HHV)	19,093	19,093	19,093
(HHV/LHV)	1.072	1.072	1.072
Fuel density (lb/gal)	6.69	6.69	6.69
CT Exhaust Flow	127808.542		
Mass Flow (lb/hr)- with margin	4,055,000	3,766,000	3,407,000
- provided	4,055,000	3,766,000	3,407,000
Temperature (°F)	1,053	1,093	1,143
Moisture (% Vol.)	10.87	11.46	13.07
Oxygen (% Vol.)	11.24	11.11	10.77
Molecular Weight	28.36	28.30	28.12
CT 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)	4,055,000	3,766,000	3,407,000
Temperature (°F)	1,053	1,093	1,143
Molecular weight	28.36	28.30	28.12
Volume flow (acfm)- calculated	2,631,766	2,514,188	2,362,720
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)	1,945	1,830	1,649
Heat content (Btu/lb, LHV)	17,803	17,803	17,803
Fuel usage (lb/hr)- calculated	109,234	102,764	92,647
(gal/hr)	16,318	15,352	13,840
HRSG Stack			
HRSG - Stack Height (ft)	125	125	125
Diameter (ft)	18	18	18
HRSG Stack Flow Conditions			
Velocity (ft/sec) = Volume flow (acfm) / [((diameter)² /4) x 3.14159] / 60 sec/min			
Mass flow (lb/hr)	4,055,000	3,766,000	3,407,000
HRSG Stack Temperature (°F)	297	295	294
Molecular weight	28.36	28.30	28.12
Volume flow (acfm)	1,316,753	1,221,963	1,110,611
Diameter (ft)	18	18	18
Velocity (ft/sec)- calculated	86.2	80.0	72.7

Note: Universal gas constant = 1,545 ft-lb(force)/°R; atmospheric pressure = 2,116.8 lb(force)/ft²; 14.7 lb/ft³

Source: GE, 2004 - CT Performance Data; Golder Associates, 2004

Table A-14. Maximum Emissions for Criteria Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, Base Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
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)			
CT (lb/hr)- provided	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	109.2	102.8	92.6
Conversion (%) from SO_2 to SO_3	9.8	9.8	9.8
MW SO_3/ SO_2 (80/64)	1.3	1.3	1.3
Conversion (%) from SO_3 to $(NH_4)_2(SO_4)$	100	100	100
MW $(NH_4)_2$ SO_4/ SO_3 (132/80)	1.7	1.7	1.7
SCR Particulate (lb/hr)- calculated	22.08	20.77	18.73
CT emission rate (lb/hr) [a]	17.0	17.0	17.0
Total HRSG emission rate (lb/hr) [a + b]	39.1	37.8	35.7
(lb/mmBtu, HHV)	0.0187	0.0193	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%
Fuel oil use (lb/hr)	109,234	102,764	92,647
lb SO2 / lb S (64/32)	2	2	2
Emission rate (lb/hr)- calculated	109.2	102.8	92.6
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 (ac 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, ppmvd @15% O_2	42	42	42
Moisture (%)	10.87	11.46	13.07
Oxygen (%)	11.24	11.11	10.77
CT Flow (acfm)	2,631,766	2,514,188	2,362,720
CT Exhaust Temperature (°F)	1,053	1,093	1,143
CT Emission rate (lb/hr)	345.9	322.3	293.5
(lb/hr)- provided	345.0	323.0	293.0
HRSG Stack emission rate (ppmvd @ 15% O_2)	10	10	10
(lb/hr)	82.4	76.7	69.9
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	20	20	20
Basis, ppmvd @ 15% O2 - calculated	14.24	14.13	13.86
Moisture (%)	10.87	11.46	13.07
Oxygen (%)	11.24	11.11	10.77
CT Flow (acfm)	2,631,766	2,514,188	2,362,720
CT Exhaust Temperature (°F)	1,053	1,093	1,143
HRSG Emission rate (lb/hr)	71.4	66.0	59.0
(lb/hr)- provided	71.0	66.0	59.0

Table A-14. Maximum Emissions for Criteria Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, Base Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
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
Basis, ppmvd @ 15% O2 - calculated	2.8	2.8	2.8
Moisture (%)	10.87	11.46	13.07
Oxygen (%) wet	11.24	11.11	10.77
CT Flow (acfm)	2,631,766	2,514,188	2,362,720
CT Exhaust Temperature (°F)	1,053	1,093	1,143
HRSG Emission rate (lb/hr)	8.01	7.45	6.79
(lb/hr)- provided	8.00	7.50	7.00
Sulfuric Acid Mist			
Sulfuric Acid Mist = SO_2 emission rate (lb/hr) x conversion rate of SO_2 to H_2SO_4 (%) x MW H_2SO_4 /MW SO_2 (98/64)			
CT SO_2 emission rate (lb/hr) - provided	109.2	102.8	92.6
CT Conversion to H_2SO_4 (% by weight) - provided	10	10	10
MW H2SO4 /MW SO2 (98/64)	1.53	1.53	1.53
HRSG Emission rate (lb/hr)	16.73	15.74	14.19
(lb/hr)- provided	10.6	9.9	9.0
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
Emission rate (lb/hr)	0.0272	0.0256	0.0231

Note: ppmvd= parts per million, volume dry; O_2= oxygen.

Source: GE, 2004 - CT Performance Data; Golder Associates, 2004

Table A-15. Maximum Emissions for Other Regulated PSD Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, Base Load

Parameter	Turbine Inlet Temperature		
	20 °F	59 °F	95 °F
Hours of Operation	1,000	1,000	1,000
Heat Input Rate (MMBtu/hr), HHV- CT	2,086	1,962	1,769
	2,086	1,962	1,769
2,3,7,8 TCDD Equivalents (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	3.80E-04	3.80E-04	3.80E-04
Heat Input Rate (MMBtu/hr)	2,086	1,962	1,769
Emission Rate (lb/hr)	7.93E-07	7.46E-07	6.72E-07
(TPY)	3.96E-07	3.73E-07	3.36E-07
Beryllium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	0.331	0.331	0.331
Heat Input Rate (MMBtu/hr)	2,086	1,962	1,769
Emission Rate (lb/hr)	6.90E-04	6.49E-04	5.86E-04
(TPY)	3.45E-04	3.25E-04	2.93E-04
Fluoride (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [b], lb/10^{12} Btu	32.54	32.54	32.54
Heat Input Rate (MMBtu/hr)	2,086	1,962	1,769
Emission Rate (lb/hr)	6.79E-02	6.38E-02	5.76E-02
(TPY)	3.39E-02	3.19E-02	2.88E-02
Hydrogen Chloride (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [c], lb/10^{12} Btu	2.15E+02	2.15E+02	2.15E+02
Heat Input Rate (MMBtu/hr)	2,086	1,962	1,769
Emission Rate (lb/hr)	4.49E-01	4.23E-01	3.81E-01
(TPY)	2.25E-01	2.11E-01	1.91E-01
Mercury (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	6.26E-01	6.26E-01	6.26E-01
Heat Input Rate (MMBtu/hr)	2,086	2,086	2,086
Emission Rate (lb/hr)	1.31E-03	1.31E-03	1.31E-03
(TPY)	6.53E-04	6.53E-04	6.53E-04

Sources: [a] EPA, 1998 (AP-42 draft revisions)
[b] EPA, 1981
[c] 4 ppm assumed based on ASTM D2880
[d] assumed based on combustion estimates from GE

Table A-16. Maximum Emissions for Hazardous Air Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, Base Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
Hours of Operation	1,000	1,000	1,000
Heat Input Rate (MMBtu/hr), HHV- CT	2,086	1,962	1,769
	2,086	1,962	1,769
Arsenic (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	7.91E+00	7.91E+00	7.91E+00
Heat Input Rate (MMBtu/hr)	2,086	1,962	1,769
Emission Rate (lb/hr)	1.65E-02	1.55E-02	1.40E-02
(TPY)	8.25E-03	7.76E-03	7.00E-03
Benzene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	1.1	1.1	1.1
Heat Input Rate (MMBtu/hr)	2,086	1,962	1,769
Emission Rate (lb/hr)	2.29E-03	2.16E-03	1.95E-03
(TPY)	1.15E-03	1.08E-03	9.73E-04
Cadmium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	3.24	3.24	3.24
Heat Input Rate (MMBtu/hr)	2,086	1,962	1,769
Emission Rate (lb/hr)	6.76E-03	6.36E-03	5.73E-03
(TPY)	3.38E-03	3.18E-03	2.87E-03
Chromium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	6.76	6.76	6.76
Heat Input Rate (MMBtu/hr)	2,086	1,962	1,769
Emission Rate (lb/hr)	1.41E-02	1.33E-02	1.20E-02
(TPY)	7.05E-03	6.63E-03	5.98E-03
Cobalt (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [b], lb/10^{12} Btu	37	37	37
Heat Input Rate (MMBtu/hr)	2,086	1,962	1,769
Emission Rate (lb/hr)	7.72E-02	7.26E-02	6.54E-02
(TPY)	3.86E-02	3.63E-02	3.27E-02
Manganese (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	432	432	432
Heat Input Rate (MMBtu/hr)	2,086	1,962	1,769
Emission Rate (lb/hr)	9.01E-01	8.48E-01	7.64E-01
(TPY)	4.50E-01	4.24E-01	3.82E-01
Nickel (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [b], lb/10^{12} Btu	86.3	86.3	86.3
Heat Input Rate (MMBtu/hr)	2,086	1,962	1,769
Emission Rate (lb/hr)	1.80E-01	1.69E-01	1.53E-01
(TPY)	9.00E-02	8.47E-02	7.63E-02
Phosphorous (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [b], lb/10^{12} Btu	3.00E+02	3.00E+02	3.00E+02
Heat Input Rate (MMBtu/hr)	2,086	1,962	1,769
Emission Rate (lb/hr)	0.625683712	0.588619505	0.530674508
(TPY)	3.13E-01	2.94E-01	2.65E-01

Table A-16. Maximum Emissions for Hazardous Air Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, Base Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
Selenium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	23	23	23
Heat Input Rate (MMBtu/hr)	2,086	1,962	1,769
Emission Rate (lb/hr)	4.80E-02	4.51E-02	4.07E-02
(TPY)	2.40E-02	2.26E-02	2.03E-02
Toluene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	237	237	237
Heat Input Rate (MMBtu/hr)	2,086	1,962	1,769
Emission Rate (lb/hr)	4.94E-01	4.65E-01	4.19E-01
(TPY)	2.47E-01	2.33E-01	2.10E-01

Sources: [a] EPA, 1998 (AP-42 draft revisions)
[b] EPA, 1996 (AP-42, Table 3.1-4)

Table A-17. Design Information and Stack Parameters for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, 75% Load

Parameter	Turbine Inlet Temperature		
	20 °F	59 °F	95 °F
Combustion Turbine Performance			
Power output (MW)	145.1	135.5	119.2
Heat rate (Btu/kWh, LHV)	10,970	11,030	11,400
(Btu/kWh, HHV)	11,765	11,829	12,226
Heat Input (MMBtu/hr, LHV)- provided	1,592	1,495	1,359
Heat Input (MMBtu/hr, LHV)- with margin	1,592	1,495	1,359
(MMBtu/hr, HHV)	1,707	1,603	1,457
Relative Humidity (%)	60	60	60
Fuel heating value (Btu/lb, LHV)	17,803	17,803	17,803
(Btu/lb, HHV)	19,093	19,093	19,093
(HHV/LHV)	1.072	1.072	1.072
CT Exhaust Flow			
Mass Flow (lb/hr)- with margin	2,991,000	2,898,000	2,783,000
- provided	2,991,000	2,898,000	2,783,000
Temperature (°F)	1,196	1,200	1,200
Moisture (% Vol.)	11.72	11.85	12.65
Oxygen (% Vol.)	10.34	10.57	10.86
Molecular Weight	28.32	28.29	28.16
CT 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)	2,991,000	2,898,000	2,783,000
Temperature (°F)	1,196	1,200	1,200
Molecular weight	28.32	28.29	28.16
Volume flow (acfm)- calculated	2,127,478	2,068,807	1,995,375
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)	1,592	1,495	1,359
Heat content (Btu/lb, LHV)	17,803	17,803	17,803
Fuel usage (lb/hr)- calculated	89,406	83,952	76,330
HRSG Stack			
HRSG - Stack Height (ft)	125	125	125
Diameter (ft)	18	18	18
HRSG Stack Flow Conditions			
Velocity (ft/sec) = Volume flow (acfm) / [((diameter)^2 /4) x 3.14159] / 60 sec/min			
Mass flow (lb/hr)	2,991,000	2,898,000	2,783,000
HRSG Stack Temperature (°F)	271	274	278
Molecular weight	28.32	28.29	28.16
CT volume flow (acfm)	938,994	914,512	886,499
Diameter (ft)	18	18	18
Velocity (ft/sec)- calculated	61.5	59.9	58.1

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, 2004 - CT Performance Data; Golder Associates, 2004

Table A-18. Maximum Emissions for Criteria Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, 75% Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
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)			
CT (lb/hr)- provided	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	89.4	84.0	76.3
Conversion (%) from SO_2 to SO_3	9.8	9.8	9.8
MW SO_3/ SO_2 (80/64)	1.3	1.3	1.3
Conversion (%) from SO_3 to $(NH_4)_2(SO_4)$	100	100	100
MW $(NH_4)_2$ SO_4/ SO_3 (132/80)	1.7	1.7	1.7
SCR Particulate (lb/hr)- calculated	18.07	16.97	15.43
CT emission rate (lb/hr) [a]	17.0	17.0	17.0
Total HRSG stack emission rate (lb/hr) [a + b]	35.1	34.0	32.4
(lb/mmBtu, HHV)	0.0203	0.0210	0.0220
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%
Fuel oil use (lb/hr)	89,406	83,952	76,330
lb SO2 / lb S (64/32)	2	2	2
Emission rate (lb/hr)- calculated	89.4	84.0	76.3
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 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, ppmvd @15% O_2	42	42	42
Moisture (%)	11.72	11.85	12.65
Oxygen (%)	10.34	10.57	10.86
CT Flow (acfm)	2,127,478	2,068,807	1,995,375
CT Exhaust Temperature (°F)	1,196	1,200	1,200
CT Emission rate (lb/hr)	280.5	263.5	239.3
(lb/hr)- provided	280.0	263.0	239.0
HRSG Stack emission rate (ppmvd @ 15% O_2)	10	10	10.0
(lb/hr)	66.8	62.7	57.0
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	20	20	20
Basis, ppmvd @ 15% O2 - calculated	12.84	13.24	13.94
Moisture (%)	11.72	11.85	12.65
Oxygen (%)	10.34	10.57	10.86
CT Flow (acfm)	2,127,478	2,068,807	1,995,375
CT Exhaust Temperature (°F)	1,196	1,200	1,200
HRSG Emission rate (lb/hr)	52.2	50.6	48.3
(lb/hr)- provided	52.0	51.0	48.0

Table A-18. Maximum Emissions for Criteria Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, 75% Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
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
Basis, ppmvd @ 15% O2 - calculated	2.5	2.6	2.8
Moisture (%)	11.72	11.85	12.65
Oxygen (%) wet	10.34	10.57	10.86
CT Flow (acfm)	2,127,478	2,068,807	1,995,375
CT Exhaust Temperature (°F)	1,196	1,200	1,200
HRSG Emission rate (lb/hr)	5.91	5.74	5.53
(lb/hr)- provided	6.00	5.50	5.50
Sulfuric Acid Mist			
Sulfuric Acid Mist = SO_2 emission rate (lb/hr) x conversion rate of SO_2 to H_2SO_4 (%) x MW H_2SO_4 /MW SO_2 (98/64)			
CT SO_2 emission rate (lb/hr) - provided	89.4	84.0	76.3
CT Conversion to H_2SO_4 (% by weight) - provided	10	10	10
MW H2SO4 /MW SO2 (98/64)	1.53	1.53	1.53
HRSG Emission rate (lb/hr)	13.69	12.86	11.69
(lb/hr)- provided	8.70	8.10	7.40
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
Emission rate (lb/hr)	0.0223	0.0209	0.0190

Note: ppmvd= parts per million, volume dry; O2= oxygen.

Source: GE, 2004 - CT Performance Data; Golder Associates, 2004

Table A-19. Maximum Emissions for Other Regulated PSD Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, 75% Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
Hours of Operation	1,000	1,000	1,000
Heat Input Rate (MMBtu/hr), HHV- CT	1,707	1,603	1,457
	1,707	1,603	1,457
2,3,7,8 TCDD Equivalents (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	3.80E-04	3.80E-04	3.80E-04
Heat Input Rate (MMBtu/hr)	1,707	1,603	1,457
Emission Rate (lb/hr)	6.49E-07	6.09E-07	5.54E-07
(TPY)	3.24E-07	3.05E-07	2.77E-07
Beryllium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	0.331	0.331	0.331
Heat Input Rate (MMBtu/hr)	1,707	1,603	1,457
Emission Rate (lb/hr)	5.65E-04	5.31E-04	4.82E-04
(TPY)	2.83E-04	2.65E-04	2.41E-04
Fluoride (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [b], lb/10^{12} Btu	32.54	32.54	32.54
Heat Input Rate (MMBtu/hr)	1,707	1,603	1,457
Emission Rate (lb/hr)	5.55E-02	5.22E-02	4.74E-02
(TPY)	2.78E-02	2.61E-02	2.37E-02
Hydrogen Chloride (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [c], lb/10^{12} Btu	2.15E+02	2.15E+02	2.15E+02
Heat Input Rate (MMBtu/hr)	1,707	1,603	1,457
Emission Rate (lb/hr)	3.68E-01	3.45E-01	3.14E-01
(TPY)	1.84E-01	1.73E-01	1.57E-01
Mercury (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	6.26E-01	6.26E-01	6.26E-01
Heat Input Rate (MMBtu/hr)	1,707	1,707	1,707
Emission Rate (lb/hr)	1.07E-03	1.07E-03	1.07E-03
(TPY)	5.34E-04	5.34E-04	5.34E-04

Sources: [a] EPA, 1998 (AP-42 draft revisions)
[b] EPA, 1981
[c] 4 ppm assumed based on ASTM D2880
[d] assumed based on combustion estimates from GE

Table A-20. Maximum Emissions for Hazardous Air Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, 75% Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
Hours of Operation	1,000	1,000	1,000
Heat Input Rate (MMBtu/hr), HHV- CT	1,707	1,603	1,457
	1,707	1,603	1,457
Arsenic (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	7.91E+00	7.91E+00	7.91E+00
Heat Input Rate (MMBtu/hr)	1,707	1,603	1,457
Emission Rate (lb/hr)	1.35E-02	1.27E-02	1.15E-02
(TPY)	6.75E-03	6.34E-03	5.76E-03
Benzene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	1.1	1.1	1.1
Heat Input Rate (MMBtu/hr)	1,707	1,603	1,457
Emission Rate (lb/hr)	1.88E-03	1.76E-03	1.60E-03
(TPY)	9.39E-04	8.82E-04	8.02E-04
Cadmium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	3.24	3.24	3.24
Heat Input Rate (MMBtu/hr)	1,707	1,603	1,457
Emission Rate (lb/hr)	5.53E-03	5.19E-03	4.72E-03
(TPY)	2.77E-03	2.60E-03	2.36E-03
Chromium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	6.76	6.76	6.76
Heat Input Rate (MMBtu/hr)	1,707	1,603	1,457
Emission Rate (lb/hr)	1.15E-02	1.08E-02	9.85E-03
(TPY)	5.77E-03	5.42E-03	4.93E-03
Cobalt (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [b], lb/10^{12} Btu	37	37	37
Heat Input Rate (MMBtu/hr)	1,707	1,603	1,457
Emission Rate (lb/hr)	6.32E-02	5.93E-02	5.39E-02
(TPY)	3.16E-02	2.97E-02	2.70E-02
Manganese (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	432	432	432
Heat Input Rate (MMBtu/hr)	1,707	1,603	1,457
Emission Rate (lb/hr)	7.37E-01	6.92E-01	6.30E-01
(TPY)	3.69E-01	3.46E-01	3.15E-01
Nickel (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [b], lb/10^{12} Btu	86.3	86.3	86.3
Heat Input Rate (MMBtu/hr)	1,707	1,603	1,457
Emission Rate (lb/hr)	1.47E-01	1.38E-01	1.26E-01
(TPY)	7.37E-02	6.92E-02	6.29E-02
Phosphorous (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [b], lb/10^{12} Btu	3.00E+02	3.00E+02	3.00E+02
Heat Input Rate (MMBtu/hr)	1,707	1,603	1,457
Emission Rate (lb/hr)	0.51211023	0.480869479	0.437209645
(TPY)	2.56E-01	2.40E-01	2.19E-01

Table A-20. Maximum Emissions for Hazardous Air Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, 75% Load

Parameter	Turbine Inlet Temperature		
	20 °F	59 °F	95 °F
Selenium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	23	23	23
Heat Input Rate (MMBtu/hr)	1,707	1,603	1,457
Emission Rate (lb/hr)	3.93E-02	3.69E-02	3.35E-02
(TPY)	1.96E-02	1.84E-02	1.68E-02
Toluene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	237	237	237
Heat Input Rate (MMBtu/hr)	1,707	1,603	1,457
Emission Rate (lb/hr)	4.05E-01	3.80E-01	3.45E-01
(TPY)	2.02E-01	1.90E-01	1.73E-01

Sources: [a] EPA, 1998 (AP-42 draft revisions)
[b] EPA,1996 (AP-42,Table 3.1-4)

Table A-21. Design Information and Stack Parameters for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, 50% Load

Parameter	Turbine Inlet Temperature		
	20 °F	59 °F	95 °F
Combustion Turbine Performance			
Power output (MW)	96.7	90.3	79.4
Heat rate (Btu/kWh, LHV)	12,730	12,920	13,370
(Btu/kWh, HHV)	13,652	13,856	14,339
Heat Input (MMBtu/hr, LHV)- provided	1,231	1,167	1,062
Heat Input (MMBtu/hr, LHV)- with margin	1,231	1,167	1,062
(MMBtu/hr, HHV)	1,320	1,251	1,139
Relative Humidity (%)	60	60	60
Fuel heating value (Btu/lb, LHV)	17,803	17,803	17,803
(Btu/lb, HHV)	19,093	19,093	19,093
(HHV/LHV)	1.072	1.072	1.072
CT Exhaust Flow			
Mass Flow (lb/hr)- with margin	2,499,000	2,457,000	2,353,000
- provided	2,499,000	2,457,000	2,353,000
Temperature (°F)	1,200	1,200	1,200
Moisture (% Vol.)	10.19	10.38	11.37
Oxygen (% Vol.)	11.30	11.54	11.73
Molecular Weight	28.44	28.40	28.26
CT 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)	2,499,000	2,457,000	2,353,000
Temperature (°F)	1,200	1,200	1,200
Molecular weight	28.44	28.40	28.26
Volume flow (acfm)- calculated	1,774,396	1,747,217	1,681,491
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)	1,231	1,167	1,062
Heat content (Btu/lb, LHV)	17,803	17,803	17,803
Fuel usage (lb/hr)- calculated	69,146	65,534	59,630
HRSG Stack			
HRSG - Stack Height (ft)	125	125	125
Diameter (ft)	18	18	18
HRSG Stack Flow Conditions			
Velocity (ft/sec) = Volume flow (acfm) / [((diameter)² /4) x 3.14159] / 60 sec/min			
Mass flow (lb/hr)	2,499,000	2,457,000	2,353,000
HRSG Stack Temperature (°F)	256	259	268
Molecular weight	28.44	28.40	28.26
CT volume flow (acfm)	765,021	756,777	737,121
Diameter (ft)	18	18	18
Velocity (ft/sec)- calculated	50.1	49.6	48.3

Note: Universal gas constant = 1,545 ft-lb(force)/°R; atmospheric pressure = 2,116.8 lb(force)/ft²; 14.7 lb/ft³

Source: GE, 2004 - CT Performance Data; Golder Associates, 2004

Table A-22. Maximum Emissions for Criteria Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, 50% Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
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)			
CT (lb/hr)- provided	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	69.1	65.5	59.6
Conversion (%) from SO_2 to SO_3	9.8	9.8	9.8
MW SO_3/ SO_2 (80/64)	1.3	1.3	1.3
Conversion (%) from SO_3 to $(NH_4)_2(SO_4)$	100	100	100
MW $(NH_4)_2$ SO_4/ SO_3 (132/80)	1.7	1.7	1.7
SCR Particulate (lb/hr)- calculated	13.98	13.25	12.05
CT emission rate (lb/hr) [a]	17.0	17.0	17.0
Total HRSG stack emission rate (lb/hr) [a + b]	31.0	30.2	29.1
(lb/mmBtu, HHV)	0.0235	0.0242	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%
Fuel oil use (lb/hr)	69,146	65,534	59,630
lb SO2 / lb S (64/32)	2	2	2
Emission rate (lb/hr)- calculated	69.1	65.5	59.6
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 (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, ppmvd @15% O_2	42	42	42
Moisture (%)	10.19	10.38	11.37
Oxygen (%)	11.30	11.54	11.73
CT Flow (acfm)	1,774,396	1,747,217	1,681,491
CT Exhaust Temperature (°F)	1,200	1,200	1,200
CT Emission rate (lb/hr)	215.0	203.7	185.2
(lb/hr)- provided	215.0	203.0	185.0
HRSG Stack emission rate (ppmvd @ 15% O_2)	10	10	10.0
(lb/hr)	51.2	48.5	44.1
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
Basis, ppmvd @ 15% O2 - calculated	14.19	14.71	15.39
Moisture (%)	10.19	10.38	11.37
Oxygen (%)	11.30	11.54	11.73
CT Flow (acfm)	1,774,396	1,747,217	1,681,491
CT Exhaust Temperature (°F)	1,200	1,200	1,200
HRSG Emission rate (lb/hr)	44.2	43.4	41.3
(lb/hr)- provided	44.0	43.0	41.0

Table A-22. Maximum Emissions for Criteria Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, 50% Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
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
Basis, ppmvd @ 15% O2 - calculated	2.8	2.9	3.0
Moisture (%)	10.19	10.38	11.37
Oxygen (%) wet	11.30	11.54	11.73
CT Flow (acfm)	1,774,396	1,747,217	1,681,491
CT Exhaust Temperature (°F)	1,200	1,200	1,200
HRSG Emission rate (lb/hr)	4.92	4.85	4.66
(lb/hr)- provided	5.00	5.00	4.50
Sulfuric Acid Mist			
Sulfuric Acid Mist = SO_2 emission rate (lb/hr) x conversion rate of SO_2 to H_2SO_4 (%) x MW H_2SO_4 /MW SO_2 (98/64)			
CT SO_2 emission rate (lb/hr) - provided	69.1	65.5	59.6
CT Conversion to H_2SO_4 (% by weight) - provided	10	10	10
MW H2SO4 /MW SO2 (98/64)	1.53	1.53	1.53
HRSG Emission rate (lb/hr)	10.59	10.03	9.13
(lb/hr)- provided	6.70	6.30	5.80
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
Emission rate (lb/hr)	0.0172	0.0163	0.0149

Note: ppmvd= parts per million, volume dry; O_2= oxygen.

Source: GE, 2004 - CT Performance Data; Golder Associates, 2004

Table A-23. Maximum Emissions for Other Regulated PSD Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, 50% Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
Hours of Operation	1,000	1,000	1,000
Heat Input Rate (MMBtu/hr), HHV- CT	1,320	1,251	1,139
	1,320	1,251	1,139
2,3,7,8 TCDD Equivalents (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	3.80E-04	3.80E-04	3.80E-04
Heat Input Rate (MMBtu/hr)	1,320	1,251	1,139
Emission Rate (lb/hr)	5.02E-07	4.75E-07	4.33E-07
(TPY)	2.51E-07	2.38E-07	2.16E-07
Beryllium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	0.331	0.331	0.331
Heat Input Rate (MMBtu/hr)	1,320	1,251	1,139
Emission Rate (lb/hr)	4.37E-04	4.14E-04	3.77E-04
(TPY)	2.18E-04	2.07E-04	1.88E-04
Fluoride (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [b], lb/10^{12} Btu	32.54	32.54	32.54
Heat Input Rate (MMBtu/hr)	1,320	1,251	1,139
Emission Rate (lb/hr)	4.30E-02	4.07E-02	3.70E-02
(TPY)	2.15E-02	2.04E-02	1.85E-02
Hydrogen Chloride (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [c], lb/10^{12} Btu	2.15E+02	2.15E+02	2.15E+02
Heat Input Rate (MMBtu/hr)	1,320	1,251	1,139
Emission Rate (lb/hr)	2.84E-01	2.70E-01	2.45E-01
(TPY)	1.42E-01	1.35E-01	1.23E-01
Mercury (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	6.26E-01	6.26E-01	6.26E-01
Heat Input Rate (MMBtu/hr)	1,320	1,320	1,320
Emission Rate (lb/hr)	8.26E-04	8.26E-04	8.26E-04
(TPY)	4.13E-04	4.13E-04	4.13E-04

Sources: [a] EPA, 1998 (AP-42 draft revisions)
[b] EPA, 1981
[c] 4 ppm assumed based on ASTM D2880
[d] assumed based on combustion estimates from GE

Table A-24. Maximum Emissions for Hazardous Air Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, 50% Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
Hours of Operation	1,000	1,000	1,000
Heat Input Rate (MMBtu/hr), HHV- CT	1,320	1,251	1,139
	1,320	1,251	1,139
Arsenic (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	7.91E+00	7.91E+00	7.91E+00
Heat Input Rate (MMBtu/hr)	1,320	1,251	1,139
Emission Rate (lb/hr)	1.04E-02	9.90E-03	9.01E-03
(TPY)	5.22E-03	4.95E-03	4.50E-03
Benzene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	1.1	1.1	1.1
Heat Input Rate (MMBtu/hr)	1,320	1,251	1,139
Emission Rate (lb/hr)	1.45E-03	1.38E-03	1.25E-03
(TPY)	7.26E-04	6.88E-04	6.26E-04
Cadmium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	3.24	3.24	3.24
Heat Input Rate (MMBtu/hr)	1,320	1,251	1,139
Emission Rate (lb/hr)	4.28E-03	4.05E-03	3.69E-03
(TPY)	2.14E-03	2.03E-03	1.84E-03
Chromium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	6.76	6.76	6.76
Heat Input Rate (MMBtu/hr)	1,320	1,251	1,139
Emission Rate (lb/hr)	8.92E-03	8.46E-03	7.70E-03
(TPY)	4.46E-03	4.23E-03	3.85E-03
Cobalt (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [b], lb/10^{12} Btu	37	37	37
Heat Input Rate (MMBtu/hr)	1,320	1,251	1,139
Emission Rate (lb/hr)	4.88E-02	4.63E-02	4.21E-02
(TPY)	2.44E-02	2.31E-02	2.11E-02
Manganese (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	432	432	432
Heat Input Rate (MMBtu/hr)	1,320	1,251	1,139
Emission Rate (lb/hr)	5.70E-01	5.41E-01	4.92E-01
(TPY)	2.85E-01	2.70E-01	2.46E-01
Nickel (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [b], lb/10^{12} Btu	86.3	86.3	86.3
Heat Input Rate (MMBtu/hr)	1,320	1,251	1,139
Emission Rate (lb/hr)	1.14E-01	1.08E-01	9.83E-02
(TPY)	5.70E-02	5.40E-02	4.91E-02
Phosphorous (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [b], lb/10^{12} Btu	3.00E+02	3.00E+02	3.00E+02
Heat Input Rate (MMBtu/hr)	1,320	1,251	1,139
Emission Rate (lb/hr)	0.396059366	0.375371619	0.341556965
(TPY)	1.98E-01	1.88E-01	1.71E-01

Table A-24. Maximum Emissions for Hazardous Air Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, 50% Load

Parameter	Turbine Inlet Temperature		
	20 °F	59 °F	95 °F
Selenium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	23	23	23
Heat Input Rate (MMBtu/hr)	1,320	1,251	1,139
Emission Rate (lb/hr)	3.04E-02	2.88E-02	2.62E-02
(TPY)	1.52E-02	1.44E-02	1.31E-02
Toluene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	237	237	237
Heat Input Rate (MMBtu/hr)	1,320	1,251	1,139
Emission Rate (lb/hr)	3.13E-01	2.97E-01	2.70E-01
(TPY)	1.56E-01	1.48E-01	1.35E-01

Sources: [a] EPA, 1998 (AP-42 draft revisions)
[b] EPA,1996 (AP-42,Table 3.1-4)

Table A-25 Summary of Maximum Potential Annual Emissions for the CT/HRSG

Pollutant	Load:	Maximum Hourly Emissions (lb/hr)[a] Natural Gas 100%	Natural Gas 50%	Distillate Oil 100%	Maximum Annual Emissions (tons/year)[b] Case A	Case B	Case C	Case D	Auxiliary Boiler	TOTAL	PSD Significant Emission Rates
One Combustion Turbine- Combined Cycle											
SO_2		5.1	3.3	102.8	22.1	19.5	71.0	68.4	0.014	71.0	40
PM/PM_{10}		10.0	9.7	37.8	44.0	43.4	57.8	57.3	0.025	57.9	25/15
NO_x		16.5	11	77	72.3	63.3	102.4	93.4	0.50	103	40
CO		29.7	19.9	66.0	130.1	115.3	148.2	133.5	0.25	148	100
VOC (as methane)		2.9	1.9	7.5	12.6	11.2	14.9	13.5	0.25	15.2	40
Sulfuric Acid Mist		0.77	0.5	15.7	3.4	3.0	10.9	10.5	0.002	10.9	7
Lead		0.00E+00	0.00E+00	2.56E-02	0.00E+00	0.00E+00	1.28E-02	1.28E-02	0.00E+00	1.28E-02	0.6
Mercury		1.44E-06	9.43E-07	1.31E-03	6.33E-06	5.58E-06	6.58E-04	6.58E-04	Neg.	6.58E-04	0.1
MWC Organics (as 2,3,7,8-TCDD)		2.17E-09	1.42E-09	7.46E-07	9.49E-09	8.36E-09	3.81E-07	3.80E-07	Neg.	3.81E-07	3.50E-06
MWC Metals (Be & Cd)		0.00E+00	0.00E+00	7.01E-03	0.00E+00	0.00E+00	3.50E-03	3.50E-03	0.00E+00	3.50E-03	15
MWC Acid Gases (HCl)		0.00E+00	0.00E+00	0.42	0.00E+00	0.00E+00	2.11E-01	2.11E-01	0.00E+00	2.11E-01	40
Total HAPs		0.41	0.30	2.54	1.79	1.63	2.86	2.70	0.40	3.26	25
Two Combustion Turbines- Combined Cycle											
SO_2		10.1	6.6	205.5	44.3	39.0	142.0	136.7	0.014	142	40
PM/PM_{10}		20	19	76	88	87	116	115	0.025	116	25/15
NO_x		33	21	153	145	127	205	187	0.50	205	40
CO		59	40	132	260	231	296	267	0.25	297	100
VOC (as methane)		5.8	3.8	14.9	25.2	22.3	29.8	26.9	0.25	30.1	40
Sulfuric Acid Mist		1.5	1.01	31.47	6.78	5.97	21.74	20.93	0.002	21.7	7
Lead		0.00E+00	0.00E+00	5.12E-02	0.00E+00	0.00E+00	2.56E-02	2.56E-02	0.00E+00	2.56E-02	0.6
Mercury		2.89E-06	1.89E-06	2.61E-03	1.27E-05	1.12E-05	1.32E-03	1.32E-03	Neg.	1.32E-03	0.1
MWC Organics (as 2,3,7,8-TCDD)		4.33E-09	2.83E-09	1.49E-06	1.90E-08	1.67E-08	7.62E-07	7.60E-07	Neg.	7.62E-07	3.50E-06
MWC Metals (Be & Cd)		0.00E+00	0.00E+00	1.40E-02	0.00E+00	0.00E+00	7.01E-03	7.01E-03	0.00E+00	7.01E-03	15
MWC Acid Gases (HCL)		0.0	0.00	0.85	0.00	0.00	4.23E-01	4.23E-01	0.00E+00	4.23E-01	40
Total HAPs		0.8	0.60	5.09	3.59	3.26	5.72	5.40	0.4	6.12	25

[a] Based on 59 °F compressor inlet air temperature

[b] Maximim emission cases:

Operation	Number of Hours for Operation Case A	Case B	Case C	Case D
100 % Load- Gas	8,760	5,760	7,760	4,760
50% Load- Gas	0	3000	0	3,000
100 % Load- Oil	0	0	1,000	1,000
Total hours	8,760	8,760	8,760	8,760

Table A-26. Formaldehyde Emissions for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 100% Load

Parameter	CT Only Turbine Inlet Temperature and Load 100% 20 °F	 100% 59 °F	 100% 95 °F
Formaldehyde (CH_2O) MW =	30		
CH_2O (lb/hr) = CH_2O (ppmvd@ 15% O_2) x {[20.9 x (1-Moisture (%)/100] - Oxygen, dry(%)} x 2116.8 lb/ft^2 x Volume flow (acfm) x 30 (mole. wgt CH2O) x 60 min/hr / [1545 x (CT temp.(°F) + 460) x (20.9-15) x 1,000,000 (adj. for ppm)]			
CT, ppmvd @15% O_2	0.091	0.091	0.091
Moisture (%)	7.55	8.37	9.88
Oxygen (%)	12.75	12.57	12.34
Turbine Flow (acfm)	2,574,253	2,461,202	2,318,987
Turbine Exhaust Temperature (°F)	1,074	1,113	1,154
CT Emission rate (lb/hr)	0.420	0.392	0.355
Heat Input (MMBtu/hr, HHV)	1941	1806	1644
CT Emission rate (lb/10^{12} Btu)	216.1	216.9	215.9

Note: ppmvd= parts per million, volume dry; O_2= oxygen.

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Table A-27. Formaldehyde Emissions for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 50% Load

Parameter	CT Only Turbine Inlet Temperature and Load 50% 20 °F	 50% 59 °F	 50% 95 °F
Formaldehyde (CH_2O) MW =	30		
CH_2O (lb/hr) = CH_2O (ppmvd@ 15% O_2) x {[20.9 x (1-Moisture (%)/100] - Oxygen, dry(%)} x 2116.8 lb/ft^2 x Volume flow (acfm) x 30 (mole. wgt CH2O) x 60 min/hr / [1545 x (CT temp.(°F) + 460) x (20.9-15) x 1,000,000 (adj. for ppm)]			
CT, ppmvd @15% O_2	0.091	0.091	0.091
Moisture (%)	7.54	7.96	9.37
Oxygen (%)	12.77	12.94	12.92
Turbine Flow (acfm)	1,770,983	1,728,651	1,662,592
Turbine Exhaust Temperature (°F)	1,200	1,200	1,200
CT Emission rate (lb/hr)	0.266	0.249	0.229
Heat Input (MMBtu/hr, HHV)	1,257	1,179	1,085
CT/DB Emission rate (lb/10^{12} Btu)	211.6	211.5	211.5

Note: ppmvd= parts per million, volume dry; O_2= oxygen.

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Table A-28. Formaldehyde Emissions for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, Base Load

Parameter	CT Only Turbine Inlet Temperature and Load 100% 20 °F	 100% 59 °F	 100% 95 °F
Formaldehyde (CH_2O) MW = 30			
CH_2O (lb/hr) = CH_2O (ppmvd@ 15% O_2) x {[20.9 x (1-Moisture (%)/100] - Oxygen, dry(%)} x 2116.8 lb/ft^2 x Volume flow (acfm) x 30 (mole. wgt CH2O) x 60 min/hr / [1545 x (CT temp.(°F) + 460) x (20.9-15) x 1,000,000 (adj. for ppm)]			
CT, ppmvd @15% O_2	0.091	0.091	0.091
Moisture (%)	10.87	11.46	13.07
Oxygen (%)	11.24	11.11	10.77
Turbine Flow (acfm)	2,631,766	2,514,188	2,362,720
Turbine Exhaust Temperature (°F)	1,053	1,093	1,143
CT Emission rate (lb/hr)	0.489	0.455	0.415
Heat Input (MMBtu/hr, HHV)	2,086	1,962	1,769
CT Emission rate (lb/10^{12} Btu)	234.4	232.1	234.5

Note: ppmvd= parts per million, volume dry; O_2= oxygen.

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Table A-29. Auxiliary Boiler Emissions for the Hines Energy Complex, Power Block 4

Parameter	Value		
Conditions			
Ambient Temperature (°F)	72		
Load Condition (%)	100		
Hear Input Rate (MMBtu/hr), maximum	20		
Fuel Usage			
Heat content (Btu/cf, HHV)	1,021		
Fuel usage (cf/hr)- calculated	19,585		
Hours of Operation	500		
Sulfur content (gr/100 scf)	1		
Emissions [a]	lb/MMBtu	lb/hr	TPY
SO_2	0.0028	0.056	0.014
PM/PM_{10}	0.005	0.10	0.025
NO_x	0.10	2.00	0.5
CO	0.049	0.98	0.25
VOC (as methane)	0.049	0.98	0.25
Sulfuric Acid Mist [c]	0.00043	0.0086	0.0021
Lead	Neg.	Neg.	Neg.
Mercury	Neg.	Neg.	Neg.
Benzene [b]	0.002	0.04	0.01
Formaldehyde [b]	0.075	1.50	0.38
Toluene [b]	0.003	0.07	0.02
Stack Parameters			
Height (ft)	60		
Diameter (ft)	2.5		
Exit gas temperature (°F)	332		
Exit gas flow rate (acfm)	6,485		
Exit gas velocity (ft/s)	22.0		

[a] Emissions based on maunufacturer's data (Black & Veatch, 1992).

[a] Emissions based on natural gas combustion from AP-42, Compilation of Air Pollutant Emission Factors for Stationary Sources, Chapter 1.4 (U.S. EPA, 1998).

[c] Based on 10 peercent of SO2 emissions.

ATTACHMENT 3

Revised BACT Tables

Table B-3. Capital Cost for Selective Catalytic Reduction and SCONOx™ for the GE 7FA Combined Cycle Combustion Turbine
(3.5 ppmvd corrected for gas firing)

Cost Component	Costs for SCR	Costs for SCONOx™	Basis of Cost Component
Direct Capital Costs			
Pollution Control Equipment	$968,481	$14,750,000	Vendor Estimates
Ammonia Storage Tank	$127,782	$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	$58,109	$885,000	6% of SCR Associated Equipment and Catalyst
Freight	$48,424	$737,500	5% of SCR Associated Equipment
Total Direct Capital Costs (TDCC)	$1,297,301	$16,492,225	
Direct Installation Costs			
Foundation and supports	$103,784	1,319,378	8% of TDCC and RCC;OAQPS Cost Control Manual
Handling & Erection	$181,622	2,308,912	14% of TDCC and RCC;OAQPS Cost Control Manual
Electrical	$51,892	659,689	4% of TDCC and RCC;OAQPS Cost Control Manual
Piping	$25,946	329,845	2% of TDCC and RCC;OAQPS Cost Control Manual
Insulation for ductwork	$12,973	164,922	1% of TDCC and RCC;OAQPS Cost Control Manual
Painting	$12,973	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)	$409,190	$4,967,668	
Total Capital Costs (TCC)	$1,706,491	$21,459,893	Sum of TDCC, TDIC and RCC
Indirect Costs			
Engineering	$129,730	$1,649,223	10% of Total DirectCapital Costs; OAQPS Cost Control Manual
PSM/RMP Plan	$50,000	$0	Engineering Estimate
Construction and Field Expense	$64,865	$824,611	5% of TDCC; OAQPS Cost Control Manual
Contractor Fees	$129,730	$1,649,223	10% of TDCC; OAQPS Cost Control Manual
Start-up	$25,946	$329,845	2% of TDCC; OAQPS Cost Control Manual
Performance Tests	$12,973	$164,922	1% of TDCC; OAQPS Cost Control Manual
Contingencies	$38,919	$494,767	3% of TDCC; OAQPS Cost Control Manual
Total Indirect Capital Cost (TInCC)	$452,163	$5,112,590	
Total Direct, Indirect and Capital Costs (TDICC)	$2,158,654	$26,572,482	Sum of TCC and TInCC

Sources: Engelhard 2000. ABB Alstom 2000. EPA 1990, 1992 and 1996 (OAQPS Cost Control Manual). Golder 2000. Vatavuk 1990 (Estimating Costs of Air Pollution Control).

Table B-3b. Capital Cost for Selective Catalytic Reduction and SCONOx™ for the GE 7FA Combined Cycle Combustion Turbine
(2.5 ppmvd corrected for gas firing)

Cost Component	Costs for SCR	Costs for SCONOx™	Basis of Cost Component
Direct Capital Costs			
Pollution Control Equipment	$1,065,329	$14,750,000	Vendor Estimates
Ammonia Storage Tank	$127,782	$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	$63,920	$885,000	6% of SCR Associated Equipment and Catalyst
Freight	$53,266	$737,500	5% of SCR Associated Equipment
Total Direct Capital Costs (TDCC)	$1,404,802	$16,492,225	
Direct Installation Costs			
Foundation and supports	$112,384	1,319,378	8% of TDCC and RCC;OAQPS Cost Control Manual
Handling & Erection	$196,672	2,308,912	14% of TDCC and RCC;OAQPS Cost Control Manual
Electrical	$56,192	659,689	4% of TDCC and RCC;OAQPS Cost Control Manual
Piping	$28,096	329,845	2% of TDCC and RCC;OAQPS Cost Control Manual
Insulation for ductwork	$14,048	164,922	1% of TDCC and RCC;OAQPS Cost Control Manual
Painting	$14,048	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)	$441,441	$4,967,668	
Total Capital Costs (TCC)	$1,846,243	$21,459,893	Sum of TDCC, TDIC and RCC
Indirect Costs			
Engineering	$140,480	$1,649,223	10% of Total DirectCapital Costs; OAQPS Cost Control Manual
PSM/RMP Plan	$50,000	$0	Engineering Estimate
Construction and Field Expense	$70,240	$824,611	5% of TDCC; OAQPS Cost Control Manual
Contractor Fees	$140,480	$1,649,223	10% of TDCC; OAQPS Cost Control Manual
Start-up	$28,096	$329,845	2% of TDCC; OAQPS Cost Control Manual
Performance Tests	$14,048	$164,922	1% of TDCC; OAQPS Cost Control Manual
Contingencies	$42,144	$494,767	3% of TDCC; OAQPS Cost Control Manual
Total Indirect Capital Cost (TInCC)	$485,489	$5,112,590	
Total Direct, Indirect and Capital Costs (TDICC)	$2,331,731	$26,572,482	Sum of TCC and TInCC

Sources: Engelhard 2000. ABB Alstom 2000. EPA 1990, 1992 and 1996 (OAQPS Cost Control Manual). Golder 2000. Vatavuk 1990 (Estimating Costs of Air Pollution Control).

Table B-4. Annualized Cost for Selective Catalytic Reduction and SCONOx™ for the GE 7FA in Combined Cycle Operation
(3.5 ppmvd corrected for gas 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	$114,985	$0	$300 per ton for Aqueous NH_3
PSM/RMP Update	$15,000	$0	Engineering Estimate
Inventory Cost	$19,384	$29,076	Capital Recovery (10.98%) for 1/3 catalyst for SCR; SCONOx 1.5 times SCR
Catalyst Cost	$176,540	$264,810	3 years catalyst life; Based on Vendor Budget Estimate
Contingency	$10,423	$10,108	3% of Direct Annual Costs
Total Direct Annual Costs (TDAC)	$357,860	$347,051	
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	$221,431	$666,860	0.20 % 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)	$249,463	$1,476,245	
Indirect Annual Costs			
Overhead	81,908	25,834	60% of Operating/Supervision Labor and Ammonia
Property Taxes	21,587	265,725	1% of Total Capital Costs
Insurance	21,587	265,725	1% of Total Capital Costs
Annualized Total Direct Capital	237,020	2,917,659	10.98% Capital Recovery Factor of 7% over 15 years times sum of TDICC
Total Indirect Annual Costs (TIAC)	$362,101	$3,474,942	
Total Annualized Costs	$969,425	$5,298,237	Sum of TDAC, TEC and TIAC
Total Cost Effectiveness (9 to 3.5)	$3,672	$20,070	per ton of NO_x Removed
Incremental Cost Effectiveness (9 to 3.5)	$3,672	$20,070	per incremental ton of NO_x Removed
	263.99	263.99	tons NOx removed /year; 3.5 ppmvd corrected to 15% oxygen

Source: Golder 2002. EPA 1993 (Alternative Control Techniques Document--NOx Emissions from Stationary Gas Turbines, Page 6-20)

Table B-4b. Annualized Cost for Selective Catalytic Reduction and SCONOx™ for the GE Frame 7FA in Combined Cycle Operation
(2.5 ppmvd corrected for gas firing)

Cost Component	Costs for SCR	Costs for SCONOx™	Basis of Cost Component
Direct Annual Costs			
Operating Personnel	$31,200	$62,400	24 hours/week at $15/hr for SCR; SCONOx 2 times SCR costs
Supervision	$4,680	$9,360	15% of Operating Personnel;OAQPS Cost Control Manual
Ammonia	$126,139	$0	$300 per ton for Aqueous NH_3
PSM/RMP Update	$15,000	$0	Engineering Estimate
Inventory Cost	$25,728	$38,592	Capital Recovery (10.98%) for 1/3 catalyst for SCR; SCONOx 1.5 times !
Catalyst Cost	$234,317	$351,475	3 years catalyst life; Based on Vendor Budget Estimate
Contingency	$13,112	$13,855	3% of Direct Annual Costs
Total Direct Annual Costs (TDAC)	$450,176	$475,682	
Energy Costs			
Electrical	$28,032	$70,080	80kW/h for SCR @ $0.04/kWh times Capacity Factor; 200 kW for SCO!
MW Loss and Heat Rate Penalty	$265,718	$666,860	0.24 % 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%
Natural Gas for SCONOx	$0	$48,737	80 lb/hr; 0.044 lb/scf; 1,020 Btu/scf; $3/mmBtu
Total Energy Costs (TEC)	$293,750	$1,476,245	
Indirect Annual Costs			
Overhead	97,211	43,056	60% of Operating/Supervision Labor and Ammonia
Property Taxes	23,317	265,725	1% of Total Capital Costs
Insurance	23,317	265,725	1% of Total Capital Costs
Annualized Total Direct Capital	256,024	2,917,659	10.98% Capital Recovery Factor of 7% over 15 years times sur
Total Indirect Annual Costs (TIAC)	$399,870	$3,492,164	
Total Annualized Costs	$1,143,795	$5,444,091	Sum of TDAC, TEC and TIAC
Total Cost Effectiveness (9 to 2.5)	$3,950	$18,799	per ton of NO_x Removed
Incremental Cost Effectiveness (3.5 to 2.5)	$6,809	$5,696	per incremental ton of NO_x Removed
	289.60	289.60	tons NOx removed /year; 2.5 ppmvd corrected to 15% oxygen

Source: Golder 2002. EPA 1993 (Alternative Control Techniques Document--NOx Emissions from Stationary Gas Turbines, Page 6-20)

Table B-5. Comparison of Alternative BACT Control Technologies for NOx on One CT/HRSG

	Alternative BACT Control Technologies		
	DLN Only	DLN with SCR (3.5 ppmvd corrected)	DLN with SCONOx™ (3.5 ppmvd corrected)
Technical Assessment	Feasible	Available, Feasible and Demonstrated	Not Demonstrated
Economic Impact [a]			
Capital Costs	included	$2,158,654	$26,572,482
Annualized Costs	included	$969,425	$5,298,237
Cost Effectiveness (per ton of Nox removed)			
Total	NA	$3,672	$20,070
Environmental Impact [b]			
Total NOx (TPY)	392	128.0	128.0
NOx Reduction (TPY)	NA	264	264
Ammonia Emissions (TPY)	0	113	0
PM Emissions (TPY)	0	12.2	0
Secondary Emissions (TPY)	0	4.4	40.4
Net Emission Reduction (TPY)	NA	-134	-224
Addition Greenhouse Gas (as CO2; tons/year)	0	2,437	22,404
Energy Impacts [c]			
Energy Use (kWh/yr) - Total	0	3,872,631	35,597,336
Energy Use (kWh/yr) - Back Pressure	0	3,171,831	9,552,254
Energy Use (kWh/yr) - Other	0	700,800	26,045,082
Energy Use (Equivalent Residential Customers/year)	0	323	2,966
Energy Use (mmBtu/yr) at 10,000 Btu/kWh	0	38,483	353,740
Energy Use (mmcf/yr) at 1,000 Btu/cf for natural gas	0	38	354
Energy Use (percent of combustion turbine output)	0	0.24%	2.24%

[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 181 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-5b. Comparison of Alternative BACT Control Technologies for NOx on One CT/HRSG

	Alternative BACT Control Technologies		
	DLN Only	DLN with SCR (2.5 ppmvd corrected)	DLN with SCONOx™ (2.5 ppmvd corrected)
Technical Assessment	Feasible	Available, Feasible and Demonstrat	Not Demonstrated
Economic Impact [a]			
Capital Costs	included	$2,331,731	$26,572,482
Annualized Costs	included	$1,143,795	$5,444,091
Cost Effectiveness (per ton of Nox removed)			
Incremental from 2.5 ppm	NA	$6,809	$5,696
Environmental Impact [b]			
Total NOx (TPY)	392	102.4	102.4
NOx Reduction (TPY)	NA	290	290
Ammonia Emissions (TPY)	0	113	0
PM Emissions (TPY)	0	12.3	0
Secondary Emissions (TPY)	0	5.1	40.4
Net Emission Reduction (TPY)	NA	-159	-249
Additional Greenhouse Gas (as CO_2; tons/year)	0	2,837	22,404
Energy Impacts [c]			
Energy Use (kWh/yr)	0	4,506,997	35,597,336
Energy Use (kWh/yr) - Back Pressure	0	3,806,197	9,552,254
Energy Use (kWh/yr) - Other	0	700,800	24,643,482
Energy Use (Equivalent Residential Customers/year)	0	376	2,966
Energy Use (mmBtu/yr) at 10,000 Btu/kWh	0	44,787	353,740
Energy Use (mmcf/yr) at 1,000 Btu/cf for natural gas	0	45	354
Energy Use (percent of combustion turbine output)	0	0.28%	2.24%

[a] See Tables B-3b, B-4b, and B-5b 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 0.34 percent of 181 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™

Pollutants	Incremental Emissions (tons/year) of SCR			Incremental Emissions (tons/year) of SCONOx™		
	Primary	Secondary	Total	Primary	Secondary	Total
Particulate	12.17	0.14	12.31		1.28	1.28
Sulfur Dioxide		0.05	0.05		0.48	0.48
Nitrogen Oxides	-263.99	2.57	-261.43	-263.99	23.58	-240.41
Carbon Monoxide		1.54	1.54		14.15	14.15
Volatile Organic Compounds		0.10	0.10		0.93	0.93
Ammonia	113.04					
Total:	-138.78	4.40	-134.38	-263.99	40.42	-223.57
Carbon Dioxide (all energy requirements)		2,437.28	2,437.28		22,403.56	22,403.56

Basis:	SCR	SCONOx™	SCONOx™
Lost Energy (mmBtu/year)	38,483	353,740 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-6b. Maximum Potential Incremental Emissions (TPY) with Selective Catalytic Reduction (SCR)
(2.5 ppm)

	Incremental Emissions (tons/year) of SCR					
Pollutants	Primary	Secondary	Total	Primary	Secondary	Total
Particulate	12.17	0.16	12.33		1.28	1.28
Sulfur Dioxide		0.06	0.06		0.48	0.48
Nitrogen Oxides	-289.60	2.99	-286.62	-289.60	23.58	-266.02
Carbon Monoxide		1.79	1.79		14.15	14.15
Volatile Organic Compounds		0.12	0.12		0.93	0.93
Ammonia	113.04					
Total:	-164.39	5.12	-159.27	-289.60	40.42	-249.18
Carbon Dioxide (all energy requirements)		2,836.53	2,836.53		22,403.56	22,403.56

Basis:	SCR	SCONOx™	SCONOx™
Lost Energy (mmBtu/year)	44,787	353,740 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-8. Direct and Indirect Capital Costs for CO Catalyst, GE 7FA in Combined Cycle Combustion Turbine

Cost Component	Costs	Basis of Cost Component
Direct Capital Costs		
CO Associated Equipment Minus Catalyst	$99,000	Vendor Quote
Flue Gas Ductwork	$44,505	Vatavauk,1990
Instrumentation	$77,300	10% of SCR Associated Equipment
Sales Tax	$5,940	6% of SCR Associated Equipment/Catalyst
Freight	$4,950	5% of SCR Associated Equipment/Catalyst
CO Catalyst	$674,000	Vendor Quote
Sales Tax	$40,440	6% of SCR Associated Equipment/Catalyst
Freight	$33,700	5% of SCR Associated Equipment/Catalyst
Total Direct Capital Costs (TDCC)	$979,835	
Direct Installation Costs		
Foundation and supports	$78,387	8% of TDCC and RCC;OAQPS Cost Control Manual
Handling & Erection	$137,177	14% of TDCC and RCC;OAQPS Cost Control Manual
Electrical	$39,193	4% of TDCC and RCC;OAQPS Cost Control Manual
Piping	$19,597	2% of TDCC and RCC;OAQPS Cost Control Manual
Insulation for ductwork	$9,798	1% of TDCC and RCC;OAQPS Cost Control Manual
Painting	$9,798	1% of TDCC and RCC;OAQPS Cost Control Manual
Site Preparation	$5,000	Engineering Estimate
Buildings	$0	
Total Direct Installation Costs (TDIC)	$298,951	
Total Capital Costs	$1,278,786	Sum of TDCC, TDIC and RCC
Indirect Costs		
Engineering	$97,984	10% of Total Direct Capital Costs; OAQPS Cost Control Manual
Construction and Field Expense	$48,992	5% of Total Direct Capital Costs; OAQPS Cost Control Manual
Contractor Fees	$97,984	10% of Total Direct Capital Costs; OAQPS Cost Control Manual
Start-up	$19,597	2% of Total Direct Capital Costs; OAQPS Cost Control Manual
Performance Tests	$9,798	1% of Total Direct Capital Costs; OAQPS Cost Control Manual
Contingencies	$29,395	3% of Total Direct Capital Costs; OAQPS Cost Control Manual
Total Indirect Capital Cost (TInDC)	$303,749	
Total Direct, Indirect and Capital Costs (TDICC)	$1,582,535	Sum of TCC and TInCC

Table B-9. Annualized Cost for CO Catalyst, GE 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
Annualized Catalyst Replacement (Catalyst+Tax+Shipping)	$285,041	38.10% Capital Recovery Factor of 7% over 3 yrs times sum of TDICC
Contingency	$8,767	3% of Direct Annual Costs
Total Direct Annual Costs (TDAC)	$300,984	
Energy Costs		
Heat Rate Penalty	$349,051	0.2% of MW output, $0.05/kW; EPA, 1993 (Page 6-20) and $6/mmBtu added fuel costs (DOE,2004)
Total Energy Costs (TDEC)	$349,051	
Indirect Annual Costs		
Overhead	$4,306	60% of Operating/Supervision Labor
Property Taxes	$15,825	1% of Total Capital Costs
Insurance	$15,825	1% of Total Capital Costs
Annualized Total Direct Capital Minus Catalyst	$91,617	10.98% Capital Recovery Factor of 7% over 15 yrs times sum of TDICC
Total Indirect Annual Costs	$127,573	
Total Annualized Costs	$777,608	Sum of TDAC, TEC and TIAC
Cost Effectiveness	$6,517	per ton of CO Removed
	$7,510	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 Only	DLN with OC
Technical Assessment	Feasible	Available, Feasible and Demonstrated
Economic Impact [a]		
Capital Costs	included	$1,582,535
Annualized Costs	included	$777,608
Cost Effectiveness		
CO Removed (per ton of CO)	NA	$6,517
Environmental Impact [b]		
Total CO (TPY)	148	29
CO Reduction (TPY)	NA	119
Net Pollutant Reduction	NA	104
Additional Greenhouse Gas (CO2; tons/yr)	--	2,004
Energy Impacts [c]		
Energy Use (kWh/yr)	0	3,184,085
Energy Use (Equivalent Residential Customers/year)	0	265
Energy Use (mmBtu/yr) at 10,000 Btu/kWh	0	31,641
Energy Use (mmcf/yr) at 1,000 Btu/cf for natural gas	0	32

[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

Pollutants		Incremental Emissions (tons/year) of SCR Primary	Secondary	Total
Particulate		12.17	0.11	12.29
Sulfur Dioxide			0.04	0.04
Nitrogen Oxides		0.00	2.11	2.11
Carbon Monoxide		-119.3	1.27	-118.1
Volatile Organic Compounds			0.08	0.08
	Total:	-107.2	3.62	-103.5
Carbon Dioxide (additional from gas firing)			2,003.9	2,003.9

Basis:

Lost Energy (mmBtu/year)	31,641

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

ATTACHMENT 4

GE Formaldehyde Data

GE Energy

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October 6, 2004

Dear Mr. Murray:

In response to increased requests for formaldehyde emissions for GE combustion turbines in light of the promulgation of the combustion turbines MACT standard (40 CFR Part 63, Subpart YYYY), GE offers the following information.

GE is not prepared at this time to offer a formaldehyde emissions guarantee pending the outcome of the petition to de-list natural gas fired combustion turbines from the MACT. GE believes that making a commercial guarantee during the MACT de-listing petitioning process may imply industry's support of the MACT standard and could possibly jeopardize the approval of the petition. Such a guarantee may also prompt state and local agencies to require permit limits that would be similar to, or more stringent than, the forthcoming MACT level. Furthermore, EPA has published a "stay" of the MACT rule, as it applies to combustion turbines covered in the de-list petition, which basically excludes such units from compliance with the MACT until the de-listing petition status is approved or rejected by the EPA.

GE has conducted formaldehyde emissions testing on a very limited number of combustion turbines, all of which were Frame 7 DLN units firing natural gas, and in a couple of instances, on distillate oil.

All of the measured formaldehyde levels from our testing are below the MACT standard level of 91 ppbvd at 15% O_2 using CARB Method 430 with modified reporting protocol due to the low level concentrations. The MACT recommends FTIR but allows for other agency-approved methods.

In summary, for the reasons stated above, GE can offer no formaldehyde emissions guarantee for GE Frame 7 DLN units. However, GE expects to meet the 91 ppbvd @ 15% O_2 formaldehyde (HCOH) level on its Frame 7 DLN combustion turbines in normal premix operation on natural gas (without add-on controls). GE expects the same to be true on our Frame 7 units when firing on distillate oil with a water injection rate set to achieve a NOx level of 42 ppm @ 15% O_2 or higher. Please note these statements are based on the condition that emissions testing is conducted using the modified CARB 430 method, or an FTIR designed with proper cell path length and elimination of sample-line interference / off-gassing.

We would be happy to discuss this further with you at any time. Please do not hesitate to contact me if you have any questions.

Best regards,

Jeanne M. Beres

Jeanne M. Beres
Manager - Env. & Acoustic Eng.

cc: F. Brooks
J. Chalfin
J. Almstead

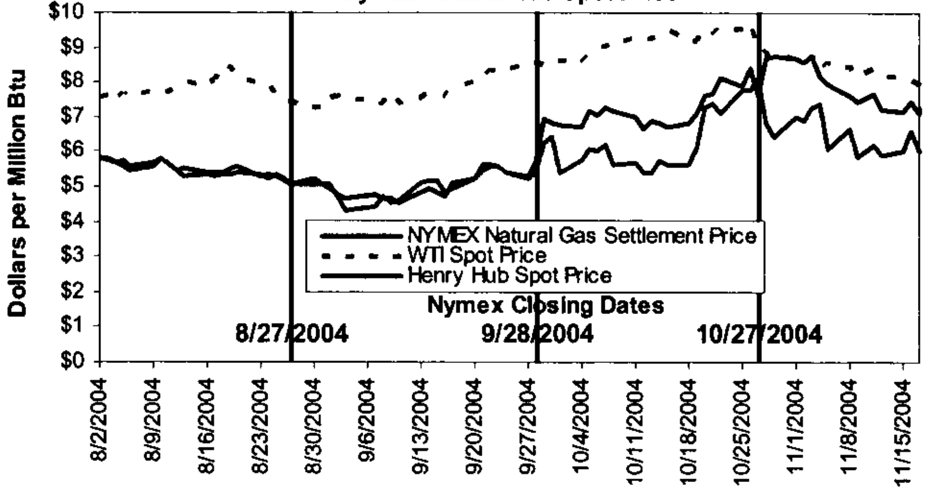
ATTACHMENT 5

Fuel Cost Data
DOE Natural Gas Weekly

Overview: Thursday, November 18 (No issue Thanksgiving week; next release 2:00 p.m. on December 2)

Natural gas spot and futures prices fell for a third consecutive week (Wednesday to Wednesday, November 10-17), as temperatures for most of the nation continued to be moderate to seasonal. At the Henry Hub, the spot price declined 6 cents on the week, for the smallest week-on-week decrease in the nation. Spot gas traded there yesterday (Wednesday, November 17) at $6.06 per MMBtu. Price declines at the majority of market locations ranged from around a dime to nearly 60 cents per MMBtu. On the NYMEX, the price for the near-month natural gas futures contract (for December delivery) fell by almost 40 cents on the week, settling yesterday at $7.283 per MMBtu. EIA reported that working gas inventories in underground storage were 3,321 Bcf as of Friday, November 12, which is 9 percent greater than the previous 5-year average. The spot price for West Texas Intermediate (WTI) crude oil declined for a fourth consecutive week, dropping $1.85 per barrel ($0.32 per MMBtu), or nearly 4 percent, from last Wednesday's level, to trade yesterday at $46.85 per barrel ($8.08 per MMBtu).

NYMEX Natural Gas Futures Near-Month Contract Settlement Price, West Texas Intermediate Crude Oil Spot Price, and Henry Hub Natural Gas Spot Price



Note: The West Texas Intermediate crude oil price, in dollars per barrel, is converted to $/MMBtu using a conversion factor of 5.80 MMBtu per barrel. The dates marked by vertical lines are the NYMEX near-month contract settlement dates.
Source: NGI's *Daily Gas Price Index* (http://intelligencepress.com)

Prices:

Spot prices declined significantly for the week at all market locations, as generally mild weather coupled with the industry's strong inventory position exerted downward pressure on prices. Price declines were largest in the West and Midcontinent and smallest in Gulf coast production areas and the Northeast. In California, high-inventory operational flow orders of varying length and condition imposed by both PG&E and SOCAL, and reports of high linepack on the Kern River Transmission pipeline, underscored the paucity of swing demand, as night-time temperatures in much of the West continue to be well above normal. The average price for Rocky Mountain locations showed the nation's largest drop for the week, at $0.48 per MMBtu, to an average of $5.25 in yesterday's trading. Spot prices at market locations in West Texas fell an average of 42 cents per MMBtu, to the low $5 range, while California points dropped 36 cents, to $5.62 per MMBtu. Thanks to a significant warming trend beginning over the weekend, prices in the Midcontinent declined from 40 to over 60 cents per MMBtu, and ranged between $5.29 and $5.88 per MMBtu in yesterday's trading. Cooler-than-expected temperatures over the weekend in the Northeast and parts of the Mid-Atlantic contributed to increased demand and boosted prices at Gulf Coast supply locations and in the Northeast region on Monday and Tuesday (November 15-16). This partially offset yesterday's large declines, leaving these market areas with smaller week-on-week decreases, which averaged 15 and 17 cents per MMBtu, respectively. The average spot price for Louisiana market locations was $5.98 per MMBtu yesterday, while spot gas for delivery to New York citygates was $6.59.

Spot Prices ($ per MMBtu)	Thur. 11-Nov	Fri. 12-Nov	Mon. 15-Nov	Tue. 16-Nov	Wed. 17-Nov
Henry Hub	6.18	5.89	6.01	6.57	6.05
New York	6.74	6.72	6.77	7.25	6.59
Chicago	6.32	6.02	6.16	6.61	5.86
Cal. Comp. Avg.*	6.01	5.70	5.90	6.29	5.64
Futures ($/MMBtu)					
December delivery	7.236	7.176	7.436	7.124	7.283
January Delivery	7.944	7.866	8.047	7.757	7.954

*Avg. of NGI's reported avg. prices for: Malin, PG&E citygate, and Southern California Border Avg.
Source: NGI's Daily Gas Price Index (http://intelligencepress.com).

On the NYMEX, the December contract settlement price declined $0.395 per MMBtu on the week, or just over 5 percent, as the near-month contract settled yesterday at $7.283. This follows the 12 percent decrease during the previous week. Since becoming the near-month contract on October 28, the December contract has fallen 16 percent in value. The futures contracts for delivery in the remaining heating-season months have shown similar declines over the same period (13 to 15 percent). Nevertheless, the basis spread between the Henry Hub spot price and the settlement prices for these contracts continues to be notably large: about $1.23, $1.91, $1.93, and $1.65, respectively, for the December through March contracts as of yesterday. This continues to provide financial incentive for injections into storage, or for limiting withdrawals from storage in favor of spot-market purchases.

Recent Natural Gas Market Data

Estimated Average Wellhead Prices						
	Apr-04	May-04	Jun-04	Jul-04	Aug-04	Sept-04
	5.20	5.63	5.85	5.60	5.36	4.86
	5.06	5.48	5.69	5.45	5.21	4.73

Note: Prices were converted from $ per Mcf to $ per MMBtu using an average heat content of 1,027 Btu per cubic foot as published in Table A4 of the Annual Energy Review 2002.
Source: Energy Information Administration, Office of Oil and Gas.

Storage:

Natural gas inventories stood at 3,321 Bcf as of Friday, November 12, according to the EIA's *Weekly Natural Gas Storage Report.* **(See Storage Figure)** The net stock change from the previous week was an implied net withdrawal of 6 Bcf, marking the first net withdrawal from storage for the two-week-old heating season. Despite the net decrease in stocks, the inventory surplus over the previous 5-year (1999-2003) average for the week increased to 9 percent, as the week's implied net withdrawal fell short of the 5-year average net withdrawal of 15 Bcf. Net withdrawals were recorded only in the East region, partially offset by small injections in the West and Producing regions. Cooler-than-normal temperatures during the week covered by the storage report in the New England and Middle Atlantic Census divisions, as measured by gas-customer weighted heating degree days (HDD), produced a moderate amount of demand in these areas and contributed to the East's net withdrawal. **(See Temperature Map)** **(See Deviations Map)** HDDs for these two Census divisions were 24.5 and 17.5 percent, respectively, above normal. Elsewhere, in divisions such as the West North Central, Mountain, and Pacific, HDDs measured 10.7, 13.8, and 2.6 percent, respectively, less than normal. Conversely, parts of West Texas and the Southwest were cooler than normal during the report week, freeing some gas for injections into storage.

All Volumes in Bcf	Current Stocks 11/12/04	One-Week Prior Stocks 11/5/04	Implied Net Change from Last Week	Estimated Prior 5-Year (1999-2003) Average	Percent Difference from 5 Year Average
East Region	1,928	1,939	-11	1,843	4.6%
West Region	425	423	2	372	14.2%
Producing Region	968	965	3	831	16.5%
Total Lower 48	3,321	3,327	-6	3,046	9.0%

Source: Energy Information Administration: Form EIA-912, "Weekly Underground Natural Gas Storage Report," and the Historical Weekly Storage Estimates Database. Row and column sums may not equal totals due to independent rounding.

Other Market Trends:

New Incentives to Help Boost Production in the Gulf of Mexico: In its first 10-year forecast for oil and gas production in the federal waters of the Gulf of Mexico, the Minerals Management Service (MMS) on November 15th said that it expects a 13-percent increase in natural gas production over the next decade. Oil production over the same timeframe will increase by approximately 43 percent, according to the agency. MMS attributed the production increase to new incentives encouraging energy companies to explore and develop difficult-to-reach areas of the Gulf of Mexico. There have been incentive programs for deep-water areas since 2001, and more recent incentives offer developers royalty relief to tap into pockets of natural gas deep under shallow waters in the Gulf. Energy companies are responding positively to the new incentives, according to MMS. By 2011, most oil production in the Gulf likely will come from deep-water wells, while natural gas will come from both the deep-water and shallow-water areas. This is the ninth year of expansion of the deep-water frontier in the Gulf, and this trend is expected to continue over the next 10 years. More than 100 development projects have begun production and new discoveries that have occurred in the past three years are expected to be developed. Natural gas production is expected to increase to 13 billion cubic feet (Bcf) per day by 2011 from current levels of about 12 Bcf per day. However, in the short term, there will be a decline in natural gas production, as old fields begin to be exhausted. This year's production estimate by MMS is based on a new methodology, which analyzes recent deep-water discoveries and projected deep-water reserves in addition to surveying oil and gas companies.

Summary:

Spot and futures prices continued on a downward trend for the third consecutive week, as the lack of significant heating demand and high inventory levels exerted downward price pressure. The basis spreads of futures prices over the Henry Hub spot price continued to be relatively large. EIA reported the first implied net withdrawal of the heating season, as of the week ended Friday, November 12.

Jeb Bush
Governor

Department of Environmental Protection

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

Colleen M. Castille
Secretary

August 19, 2004

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Roger Zirkle, Plant Manager
Progress Energy Florida
100 Central Avenue
St. Petersburg, FL 33701

Re: Request for Additional Information
Hines Energy Complex Power Block 4
File No. 1050234-010-AC

Dear Mr. Zirkle:

The Department is in receipt of your PSD application, however in order to continue processing the application, we will need the additional information 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.

Request for permit revisions

I. Progress has requested permission to operate for up to 3000 hours per year below 60% output, however within Appendix A "Emission Estimates", data was provided for only the 100%, 80% and 60% (65% for distillate) output cases.
   A) Please provide the same data for the 50% 30% and 10% CT output cases for natural gas.
   B) Should Progress desire to be permitted for any operation below 65% CT output while firing distillate oil, then FDEP requires the same data (50%, 30% and 10% output) for the distillate oil cases.
   C) Please indicate the lowest CT output (%) at which continuous operation is sought (on each fuel).
   D) Please provide CT/HRSG/Steam Turbine heat balance diagrams (see attached 'example' from a conventional steam plant) for each of the CT outputs defined above (10%, 30%, 50%, 60%, 80% and 100%)

II. Progress has requested up to eight hours per day of combined excess emissions for a cold start-up and up to five hours of combined excess emissions per day for any steam turbine shutdown. Further, Progress wishes to define a cold start-up as 'following a shutdown of the steam turbine lasting at least 48 hours'.
   A) Based upon prior guidance from EPA Region 4, the Department is not inclined to grant such lengthy time periods for unlimited excess emissions. Instead, the Department will consider the development of alternative emission limits for routine operations where full-load emission limits cannot be achieved (this includes periods such as start-up and shut-downs, and perhaps even extended periods of operation during low load, as has been requested herein). In order for the Department to evaluate alternative emission limits for such operations, actual emission estimates will be required. Therefore, for any pollutant whereby Progress expects to be unable to meet a "full load" BACT established emission limit (but specifically during a steam turbine shutdown and cold start-up), the Department will need to be provided with estimated emission curves during those time periods. This should include each of the stages of the event (e.g. cold startup) including the purpose, operating load, duration at that operating load, and estimated emissions at that operating load.
   B) Please support the (above) proposed definition of a cold start-up ('following a shutdown of the steam turbine lasting at least 48 hours') by providing:
      1) The manufacturers criteria for what constitutes a cold start-up (e.g. turbine manufacturers typically identify the first stage metal temperature on the steam turbine) and
      2) The additional operational measures which the equipment manufacturer requires to be taken as a result of the cold-start-up criteria being met.

III. Within Section 2 of the PSD application, Progress states "At present there are no confirmed test data of formaldehyde emissions from similar Siemens Westinghouse or equivalent combustion turbines." In order to be thorough, the Department requests that Progress contact the manufacturer (Siemens Westinghouse) to obtain test data for formaldehyde emissions on 501F machines. Should Westinghouse not have access to any such data, please request that they provide written confirmation to this effect.

IV. Regarding the proposed BACT Determination for CO:

A) Please confirm the evaluated placement position of the oxidation catalyst (within the flue gas stream) for Hines Power Block 4 is directly after the CT (and before the HRSG), as suggested in Appendix B, page 14. If this is not the desired placement, please specify the position in the flue gas stream as precisely as possible.

B) The Department notes the following discrepancies between the provided cost effectiveness calculation and the OAQPS Control Cost Manual:

1) Indirect Costs are to be based upon a percentage of the Direct Capital Costs (TDCC in your supplied calculation), exclusive of the Direct Installation Costs (TDIC). The submitted evaluation shows indirect costs as based upon the sum of TDCC and TDIC (referred to as Total Capital Costs).
2) The "Inventory Cost" associated with the Catalyst Replacement Cost is not an acceptable entry.
3) The Capital Recovery (referred to as Annualized Total Direct Capital in the submitted evaluation) should **exclude** the initial cost of the catalyst (times freight and sales tax).
4) Heat Rate Penalty – Please provide the Department with the assumed fuel cost (in $/MMBtu) which was utilized as a basis for adding $3/MMBtu in the "Heat Rate Penalty" calculation.

C) Please provide the basis for the estimated TPY of CO removed which was utilized in the submitted cost effectiveness of $3,773 per ton

D) Please provide the basis for the estimated net TPY emission reduction, which was utilized in the submitted cost effectiveness of $4,070 per ton

Please note that EPA and NPS have been copied on your application, and should FDEP receive questions or comments from them, we will forward you a copy.

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. Please note that per Rule 62-4.055(1): "The applicant shall have ninety days after the Department mails a timely request for additional information to submit that information to the Department.......... Failure of an applicant to provide the timely requested information by the applicable date shall result in denial of the application."

If you have any questions, please call Michael P. Halpin, P.E. at 850/921-9519.

Sincerely,

Michael P. Halpin, P.E.
DARM/BAR
North Permitting Section

Jamie Hunter, Progress
Scott Osbourn, Golder
Jim Little, EPA Region 4
Buck Oven, DEP-Siting
Jerry Kissel, DEP-SWD

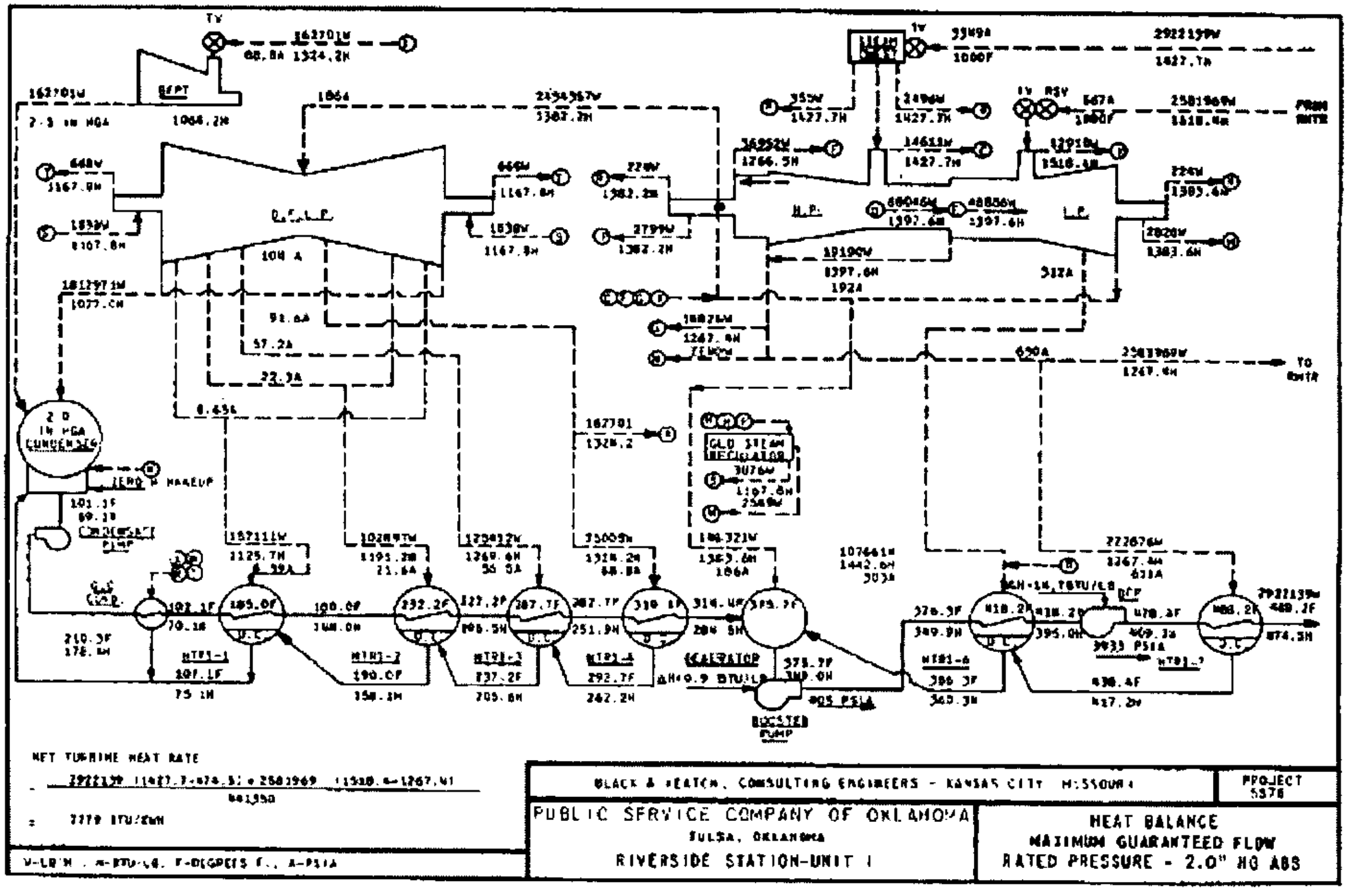


FIGURE 2.13 Thermodynamic properties and flow rates in a modern natural-gas-burning steam power plant—PSO Riverside Station Unit #1. (Courtesy of Public Service Company of Oklahoma.)

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- Print your name and address on the reverse so that we can return the card to you.
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1. Article Addressed to:

Mr. Roger Zirkle, Plant Manager
Progress Energy Florida
100 Central Avenue
St. Petersburg, Florida 33701

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)*

B. Date of Delivery 8/25

C. Signature

X ☐ Agent ☐ Addressee

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Mr. Roger Zirkle, Plant Manager

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City, State, ZIP+ 4 St. Petersburg, Florida 33701

PS Form 3800, January 2001 See Reverse for Instructions