City of Tallahassee
Your Own Utilities℠

[3]00 South Adams Street, Box A-2, Tallahassee, Florida 32301, (850) 891-4YOU (4968), talgov.com

June 6, 2006

Hamilton S. Oven, Administrator
Siting Coordination Office
Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Hand Delivered

Re: City of Tallahassee
Arvah B. Hopkins Generating Station
Hopkins Unit 2
Request for Modification of Site Certification
No. PA 74-03

Dear Mr. Oven:

Pursuant to Section 403.516, Florida Statutes, the City of Tallahassee (City) hereby requests a modification of the Site Certification for Unit No. 2 at the City's Arvah B. Hopkins Electric Generating Station (Hopkins). By this request, the City is seeking approval to "repower" the existing, certified Hopkins Unit 2 by retiring the existing oil and gas-fired boiler and installing a new combustion turbine and heat recovery steam generator.

The repowering project will not result in an increase in steam electric generating capacity at the Hopkins site. Therefore, a modification of the site certification is necessary. Detailed information regarding the repowering project is provided in the attached application for modification of site certification. The factual reasons supporting the modification and the anticipated effects of the proposed modification on the City, the public and the environment are addressed in this application.

Enclosed, please find a check in the amount of $10,000 made payable to the Department of Environmental Protection as required under Rule 62-17.293(1)(c)2., Florida Administrative Code.

The City requests that the Florida Department of Environmental Protection (Department) undertake a review of this request for modification by consulting with the other affected agencies. Upon conclusion of that review, the City requests that the Department issue a Proposed Order of Modification for review by the parties and the public, and ultimately, a Final Order granting the requested modification of certification.

The City looks forward to working with the Department and the various agencies that will be involved in reviewing this requested modification. Should you have any questions or concerns regarding this modification request, please do not hesitate to contact me at (850) 891-8851, or Rob McGarrah, Manager of Power Production at (850) 891-5534.

Sincerely,

John K. Powell, P.E.
Interim Environmental and Safety Manager

Attachments

cc: Scott Goorland, Esq., FDEP
Parties to Hopkins Unit 2 Certification
FDEP Bureau of Air Regulation (P.E. Sealed Air Permit)

AIR PERMIT APPLICATION FOR THE
CITY OF TALLAHASSEE
ARVAH B. HOPKINS GENERATING STATION
UNIT NO. 2 REPOWERING PROJECT
LEON COUNTY, FLORIDA

Prepared For:
City of Tallahassee
300 South Adams Street
Tallahassee, Florida

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

May 2006
063-7522

DISTRIBUTION:
4 Copies – FDEP
3 Copies – City of Tallahassee
2 Copies – Golder Associates Inc.

APPLICATION FOR AIR PERMIT – LONG FORM

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 at a facility operating under a federally enforceable state air operation permit (FESOP) or Title V air permit. Also 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
- Where the applicant proposes to establish, revise, or renew a plantwide applicability limit (PAL).

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: **City of Tallahassee, Electric Utilities**	
2. Site Name: **Arvah B. Hopkins Generating Station**	
3. Facility Identification Number: **0730003**	
4. Facility Location...: Street Address or Other Locator: **Route 4, Box 450, 1125 Geddie Road (County Road 1585)** City: **Tallahassee** County: **Leon** Zip Code: **32304**	
5. Relocatable Facility? ☐ Yes ☒ No	6. Existing Title V Permitted Facility? ☒ Yes ☐ No

Application Contact

1. Application Contact Name: **John K. Powell, J.D., P.E., Environmental Resources**
2. Application Contact Mailing Address... Organization/Firm: **City of Tallahassee, Environmental Resources** Street Address: **City Hall, 300 South Adams Street** City: **Tallahassee** State: **Florida** Zip Code: **32301-1731**
3. Application Contact Telephone Numbers... Telephone: **(850) 891-8851** ext. Fax: **(850) 891-8277**
4. Application Contact Email Address: **powellj@talgov.com**

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	3. PSD Number (if applicable):
2. Project Number(s):	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 construction permit to establish, revise, or renew a plantwide applicability limit (PAL).

☐ Air construction permit to establish, revise, or renew a plantwide applicability limit (PAL), and separate air construction permit to authorize construction or modification of one or more emissions units covered by the PAL.

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

This application is for repowering of Unit No. 2 with a new GE 7FA combined-cycle combustion turbine (CT). City of Tallahassee proposes to permanently shut down the boiler associated with Unit No. 2 and construct a new GE 7FA CT. The CT can operate in combined cycle mode, with and without a duct burner, and simple cycle mode firing natural gas and distillate fuel oil with exhaust gases routed to the heat recovery steam generator (HRSG) and selective catalytic reduction (SCR) system. The duct burner will be fired with natural gas. In addition, the CT can operate in simple cycle mode firing natural gas only with exhaust gases routed to an emergency bypass stack, instead of the HRSG and SCR system. Emission netting results in pollutant emission increases below the PSD significant thresholds. See Part B.

APPLICATION INFORMATION

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Proc. Fee
CT2A	GE 7FA Combined-Cycle Combustion Turbine and Duct Burner	AC1A	N/A

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 : **Robert E. McGarrah, Production Superintendent**
2.	Owner/Authorized Representative Mailing Address... Organization/Firm: **City of Tallahassee, Electric Utilities** Street Address: **2602 Jackson Bluff Road** City: **Tallahassee** State: **Florida** Zip Code: **32304**
3.	Owner/Authorized Representative Telephone Numbers... Telephone: **(850) 891-5534** ext. Fax: **(850) 891-5162**
4.	Owner/Authorized Representative Email Address: **McGarraR@talgov.com**
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.* RMcGarrah 6/1/06 Signature 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: **Kennard F. Kosky**
   Registration Number: **14996**

2. Professional Engineer Mailing Address...
   Organization/Firm: **Golder Associates Inc.****
   Street Address: **6241 NW 23rd Street, Suite 500**
   City: **Gainesville** State: **FL** Zip Code: **32653**

3. Professional Engineer Telephone Numbers...
   Telephone: **(352) 336-5600** ext.**516** Fax: **(352) 336-6603**

4. Professional Engineer Email Address: **kkosky@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] 5/31/06

Signature Date

(seal) KENNARD F. KOSKY LICENSE No. 14996 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 **16** East (km) **749.53** North (km) **3371.7**		2. Facility Latitude/Longitude... Latitude (DD/MM/SS) **30/27/08** Longitude (DD/MM/SS) **84/24/00**	
3. Governmental Facility Code: **4**	4. Facility Status Code: **A**	5. Facility Major Group SIC Code: **49**	6. Facility SIC(s): **4911**
7. Facility Comment :			

Facility Contact

1. Application Contact Name: **John K. Powell, J.D., P.E., Environmental Resources**
2. Application Contact Mailing Address... Organization/Firm: **City of Tallahassee, Environmental Resources** Street Address: **City Hall, 300 South Adams Street** City: **Tallahassee** State: **Florida** Zip Code: **32301-1731**
3. Application Contact Telephone Numbers... Telephone: **(850) 891-8851** ext. Fax: **(850) 891-8277**
4. Application Contact Email Address: **powellj@talgov.com**

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: **NSPS - 40 CFR Part 60, Subpart GG, applies to the proposed turbine and Subpart Da applies to the HRSG duct burner. However, the proposed 40 CFR Part 60, Subpart KKKK, eventually will replace Subpart GG. Under Subpart KKKK, the duct burner would be exempt from meeting the requirements of Subpart Da. NESHAP- 40 CFR Part 63, Subpart YYYY may apply based on actual oil fuel used in a calendar year.**	

FACILITY INFORMATION

List of Pollutants Emitted by Facility

1. Pollutant Emitted	2. Pollutant Classification	3. Emissions Cap [Y or N]?
Particulate Matter - PM	**A**	**No**
Particulate Matter with an aerodynamic diameter less than 10 microns - PM_{10}	**A**	**No**
Sulfur Dioxide - SO_2	**A**	**No**
Nitrogen Oxides - NO_x	**A**	**No**
Carbon Monoxide - CO	**A**	**No**
Volatile Organic Compounds - VOCs	**A**	**No**
Total Hazardous Air Pollutants – HAPs	**A**	**No**
Sulfuric Acid Mist – SAM	**A**	**No**

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:**Part B** ☐ 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: **Part B** ☐ 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:_____ ☐ Previously Submitted, Date:_____	

Additional Requirements for Air Construction Permit Applications

1. Area Map Showing Facility Location: ☐ Attached, Document ID:_____ ☒ Not Applicable (existing permitted facility)	
2. Description of Proposed Construction, Modification, or Plantwide Applicability Limit (PAL): ☒ Attached, Document ID: **Part B**	
3. Rule Applicability Analysis: ☒ Attached, Document ID: **Part B**	
4. List of Exempt Emissions Units (Rule 62-210.300(3)(a) or (b)1., F.A.C.): ☒ Attached, Document ID:**Part B** ☐ 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. Air Quality Analysis (Rule 62-212.400(7), 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	

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:
   One nominal 188-MW GE 7-FA Combined-Cycle Combustion Turbine with HRSG Duct Firing.

3. Emissions Unit Identification Number: **009**

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:
   Manufacturer: **General Electric** Model Number: **7-FA**

10. Generator Nameplate Rating: **188** MW

11. Emissions Unit Comment:
    Based on natural gas-firing at 25°F for CT only. For distillate oil-firing, rating is 199 MW at 25°F.

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description: **025 – Staged Combustion [Dry Low-NO_x (DLN) Burners]** **028 – Water Injection** **139 – Selective Catalytic Reduction (SCR)**
2. Control Device or Method Code(s): **025, 028, 139**

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: **188 MW (nominal)**	
3. Maximum Heat Input Rate: **2,664** million Btu/hr **(HHV)**	
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: **Maximum heat input for natural gas-firing at 25 °F, includes 1,899 MMBtu/hr (HHV) heat input from the combustion turbine and 765 MMBtu/hr (HHV) heat input from duct firing. Maximum heat input from oil firing is 2,079 MMBtu/hr (HHV) heat input from the combustion turbine plus 765 MMBtu/hr (HHV) heat input from duct firing natural gas. Heat input varies based on inlet temperature and performance. See Part B.**	

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: **Part B**		2. Emission Point Type Code: **1**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: **V**	6. Stack Height: **150** feet	7. Exit Diameter: **18** feet
8. Exit Temperature: **188** °F	9. Actual Volumetric Flow Rate: **1,016,100** acfm	10. Water Vapor: **11.2** %
11. Maximum Dry Standard Flow Rate: dscfm		12. Nonstack Emission Point Height: feet
13. Emission Point UTM Coordinates... Zone: **16** East (km): **749.7** North (km): **3371.7**		14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)
15. Emission Point Comment: **Information at baseload conditions for natural gas-firing with the duct burner at 59°F ambient temperature. See Part B, Appendix A of the Air Permit Application for performance at various ambient temperatures and loads. The design includes a simple cycle emergency bypass stack with a stack height of 150 feet and a diameter of 18 feet.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type): **Internal Combustion Engine – Electric Generation; Turbine, Natural Gas**		
2. Source Classification Code (SCC): **2-01-002-01**	3. SCC Units: **Million Cubic Feet**	
4. Maximum Hourly Rate: **2.571**	5. Maximum Annual Rate: **18,323**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **1,036**
10. Segment Comment: **Maximum hourly rate is for one turbine at 25°F ambient and includes duct firing. Maximum annual rate is based on total of 8,760 hours of operation at 59°F, with 2,598,800 MMBtu/yr of duct firing. See Part B, Appendix A, of the Air Permit Application for performance at various ambient temperatures and loads.**		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type): **Internal Combustion Engine – Electric Generation; Turbine, Distillate Oil**		
2. Source Classification Code (SCC): **2-01-001-01.**	3. SCC Units: **1,000 gallons**	
4. Maximum Hourly Rate: **16.0**	5. Maximum Annual Rate: **53,276**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **130**
10. Segment Comment: **Maximum hourly rate is for one turbine at 25°F ambient and includes maximum duct firing. Maximum annual rate is based on maximum heat input rate of 6,926,500 MMBtu/yr (equivalent to 3,500 hours of operation) at 59°F ambient temperature for the CT. See Part B, Appendix A, of the Air Permit Application for performance at various ambient temperatures, loads, and duct firing.**		

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/PM_{10}			EL
SO_2			EL
NO_x	028	139	EL
CO			EL
VOCs			EL

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/PM_{10}**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **48.7** lb/hour **111.8** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: **See Part B, Air Permit Application Report.**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): **97.5** tons/year	8.b. Baseline 24-month Period: From: **1/1/2004** To: **12/31/2005**
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **Maximum hourly rate based on full-load oil firing in CT and duct burner firing gas at 59°F. Annual emissions based on an equivalent 5,260 hours of natural gas firing with maximum heat input rate of 2,598,800 MMBtu/yr for duct firing at full load and maximum heat input rate of 6,926,500 MMBtu/yr (equivalent to 3,500 hours) of distillate oil-firing of the CT at full load and 59°F. Refer to Part B.**	
11. Pollutant Potential/Estimated Fugitive Emissions Comment: **See Section 2.0 of Part B and Appendix A for performance at various ambient temperatures and loads.**	

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: **21.1** lb/hour **65.2** tons/year
5. Method of Compliance: **EPA Method 9; Initial and once annually.**	
6. Allowable Emissions Comment (Description of Operating Method): **Maximum hourly rate based on natural gas-firing in CT and duct burner at 25°F and full load. Annual emission rate based on natural gas-firing with a maximum heat input rate of 2,598,800 MMBtu/yr of duct firing at 59°F and full load. Refer to Part B.**	

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% Opacity**	4. Equivalent Allowable Emissions: **38.7** lb/hour **65.8** tons/year
5. Method of Compliance: **EPA Method 9; Initial; Annual, if >400 hr/yr.**	
6. Allowable Emissions Comment (Description of Operating Method): **Maximum hourly rate based on distillate oil-firing in CT at 59°F and full load. Annual emission rate based on maximum heat input rate of 6,926,500 MMBtu/yr (equivalent to 3,500 hours) of distillate oil-firing of CT at 59°F and full load. Refer to Part B.**	

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: **111** lb/hour **211.7** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: **See Part B, Air Permit Application Report.**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): **1,642** tons/year	8.b. Baseline 24-month Period: From: **2/1/2004** To: **1/31/2006**
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **Maximum hourly rate based on full-load oil firing in CT and duct burner firing gas at 25°F. Annual emissions based on an equivalent 5,260 hours of natural gas firing with maximum heat input rate of 2,598,800 MMBtu/yr for duct firing at full load and 6,926,500 MMBtu/yr (equivalent to 3,500 hours) of distillate oil-firing of the CT at full load and 59°F. Refer to Part B.**	
11. Pollutant Potential/Estimated Fugitive Emissions Comment: **See Section 2.0 of Part B and Appendix A for performance at various ambient temperatures and loads.**	

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.

<u>**Allowable Emissions**</u> 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 grains S/100 SCF**	4. Equivalent Allowable Emissions: **14.7** lb/hour **50.5** tons/year
5. Method of Compliance: **Fuel analysis**	
6. Allowable Emissions Comment (Description of Operating Method): **Maximum hourly rate based on natural gas-firing in CT and duct burner at 25°F and full load. Annual emission rate based on natural gas-firing with a maximum heat input rate of 2,598,800 MMBtu/yr of duct firing at 59°F and full load. Refer to Part B.**	

<u>**Allowable Emissions**</u> 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**	4. Equivalent Allowable Emissions: **107** lb/hour **178.5** tons/year
5. Method of Compliance: **Fuel analysis**	
6. Allowable Emissions Comment (Description of Operating Method): **Maximum hourly rate based on distillate oil-firing in CT at 25°F and full load. Annual emission rate based on maximum heat input rate of 6,926,500 MMBtu/yr (equivalent to 3,500 hours) of distillate oil-firing of CT at 59°F and full load. Refer to Part B.**	

<u>**Allowable Emissions**</u> 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: **108.4** lb/hour **265.7** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: **See Part B, Air Permit Application Report.**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): **843.3** tons/year	8.b. Baseline 24-month Period: From: **5/1/2003** To: **4/30/2005**
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:
Maximum hourly rate based on full-load oil firing in CT and duct burner firing gas at 25°F. Annual emissions based on an equivalent 8,760 hours of natural gas firing for simple cycle operation at full load and 59°F with exhaust gases routed to emergency bypass stack. Potential annual emissions for combined cycle operation are based on an equivalent 5,260 hours of natural gas firing with maximum heat input rate of 2,598,800 MMBtu/yr for duct firing at full load and 6,926,500 MMBtu/yr (equivalent to 3,500 hours) of distillate oil-firing at full load and 59°F. Refer to Part B.

11. Pollutant Potential/Estimated Fugitive Emissions Comment:
See Section 2.0 of Part B and Appendix A for performance at various ambient temperatures and loads.

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: **5 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **47.8** lb/hour **164.9** tons/year
5. Method of Compliance: **CEMS 30-day rolling average**	
6. Allowable Emissions Comment (Description of Operating Method): **Maximum hourly rate based on natural gas-firing in CT and duct burner at 25°F and full load. Annual emission rate based on natural gas-firing with a maximum heat input rate of 2,598,800 MMBtu/yr of duct firing at 59°F and full load. Refer to Part B**	

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 @ 15% O_2 for CT**	4. Equivalent Allowable Emissions: **108.4** lb/hour **135.6** tons/year
5. Method of Compliance: **CEMS 30-day rolling average.**	
6. Allowable Emissions Comment (Description of Operating Method): **Maximum hourly rate based on distillate oil-firing in CT and duct burner(gas) at 25°F and full load. Annual emission rate based on maximum heat input rate of 6,926,500 MMBtu/yr (equivalent to 3,500 hours) of distillate oil-firing of CT at 59°F and full load.**	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **9 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **61.8** lb/hour **255.6** tons/year
5. Method of Compliance: **CEMS (see Part B)**	
6. Allowable Emissions Comment (Description of Operating Method): **For simple cycle operation with emergency bypass stack. Maximum hourly rate based on natural gas-firing in CT at 25°F and full load. Annual emission rate based on an equivalent 8,760 hours of operation at 59°F and full load. Refer to Part B**	

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: **142.9** lb/hour **340.1** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: **See Part B, Air Permit Application Report.**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): **241.1** tons/year	8.b. Baseline 24-month Period: From: **1/1/2001** To: **12/31/2002**
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:
Maximum hourly rate based on full-load oil firing in CT and duct burner firing gas at 25°F. Annual emissions based on an equivalent 5,260 hours of natural gas firing with maximum heat input rate of 2,598,800 MMBtu/yr for duct firing at full load and 6,926,500 MMBtu/yr (equivalent to 3,500 hours) of distillate oil-firing in the CT burner at full load and 59°F. Refer to Part B.

11. Pollutant Potential/Estimated Fugitive Emissions Comment:
See Section 2.0 of Part B and Appendix A for performance at various ambient temperatures and loads.

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: **16.8 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **96.8** lb/hour **264.6** tons/year
5. Method of Compliance: **EPA Method 10**	
6. Allowable Emissions Comment (Description of Operating Method): **Maximum hourly rate based on natural gas-firing in CT and duct burner (gas) at 25°F and full load. Annual emission rate based on natural gas-firing with a maximum heat input rate of 2,598,800 MMBtu/yr of duct firing at 59°F and full load. 10 ppmvd at 15% O_2 for CT only. Refer to Part B.**	

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: **21.4 ppmvd @ 15% O_2 with duct firing.**	4. Equivalent Allowable Emissions: **142.9** lb/hour **143.9** tons/year
5. Method of Compliance: **EPA Method 10; Initial; Annual >400 hr/yr.**	
6. Allowable Emissions Comment (Description of Operating Method): **Maximum hourly rate based on distillate oil-firing in CT and duct burner (gas) at 25°F and full load. Annual emission rate based on maximum heat input rate of 6,926,500 MMBtu/yr (equivalent to 3,500 hours) of distillate oil-firing of CT at 59°F and full load. 17.7 ppmvd at 15% O_2 for CT only. Refer to Part B.**	

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: **VOCs**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **17.1** lb/hour **47.4** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: **See Part B, Air Permit Application Report.**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): **19.7** tons/year	8.b. Baseline 24-month Period: From: **1/1/2004** To: **12/31/2005**
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **Maximum hourly rate based on full-load oil firing in CT and duct burner firing gas at 25°F. Annual emissions based on an equivalent 5,260 hours of natural gas firing with maximum heat input rate of 2,598,800 MMBtu/yr for duct firing at full load and 6,926,500 MMBtu/yr (equivalent to 3,500 hours) of distillate oil-firing in the CT at full load and 59°F. Refer to Part B.**	
11. Pollutant Potential/Estimated Fugitive Emissions Comment: **See Section 2.0 of Part B and Appendix A for performance at various ambient temperatures and loads.**	

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: **5.7 ppmvd @ 15% O_2 for CT and HRSG**	4. Equivalent Allowable Emissions: **16.7** lb/hour **46.8** tons/year
5. Method of Compliance: **EPA Method 25A, Initial performance test only.**	
6. Allowable Emissions Comment (Description of Operating Method): **Maximum hourly rate based on natural gas-firing in CT and duct burner at 25°F and full load. Annual emission rate based on natural gas-firing with a maximum heat input rate of 2,598,800 MMBtu/yr of duct firing at 59°F and full load. 3.2 ppmvd at 15% O_2 for CT only. Refer to Part B.**	

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: **5.3 ppmvd @ 15% O_2 for CT and DB**	4. Equivalent Allowable Emissions: **17.1** lb/hour **13.1** tons/year
5. Method of Compliance: **EPA Method 25A, Initial performance test only**	
6. Allowable Emissions Comment (Description of Operating Method): **Maximum hourly rate based on distillate oil-firing in CT and duct burner (gas) at 25°F and full load. Annual emission rate based on maximum heat input rate of 6,926,500 MMBtu/yr (equivalent to 3,500 hours) of distillate oil-firing of CT at 59°F and full load. Refer to Part B.**	

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: **VE10**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: **10** % Exceptional Conditions: **100** % Maximum Period of Excess Opacity Allowed: **60** min/hour	
4. Method of Compliance: **EPA Method 9**	
5. Visible Emissions Comment: **Rule 62-296.320 (4) (b). Excess emissions. Refer to Part B.**	

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: **TBD** Model Number: **TBD** Serial Number: **TBD**	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **TBD = To be determined. CEM required pursuant to 40 CFR Part 75.**	

Continuous Monitoring System: Continuous Monitor 2 of 2

1. Parameter Code: **O_2 or CO_2**	2. Pollutant(s): **Oxygen or Carbon Dioxide**
3. CMS Requirement: ☒ Rule ☐ Other	
4. Monitor Information... Manufacturer: **TBD** Model Number: **TBD** Serial Number: **TBD**	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **Diluent monitor required pursuant to 40 CFR Part 75 for NO_x 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: **Part B** ☐ 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: **Part B** ☐ 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: **Part B** ☐ 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: _____ ☒ 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: **Part B** ☒ 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: **Part B** ☒ Not Applicable	
3. Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only) ☒ Attached, Document ID: **Part B** ☐ 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

PART B

TABLE OF CONTENTS

1.0 INTRODUCTION 1-1

2.0 PROJECT DESCRIPTION 2-1

2.1 Site Description 2-1

2.2 Unit No. 2 Repowering Project 2-1

2.2.1 Shutdown of Existing Unit No. 2 Boiler 2-1
2.2.2 Proposed Unit 2-1

2.3 Proposed Source Emissions and Stack Parameters 2-3

2.3.1 Shutdown of Existing Unit No. 2 2-3
2.3.2 Proposed Unit 2-4

2.4 Site Layout, Structures, and Stack Sampling Facilities 2-7

3.0 AIR QUALITY REVIEW REQUIREMENTS AND APPLICABILITY 3-1

3.1 National and State Aaqs 3-1

3.2 New Source Review Requirements 3-1

3.2.1 General Requirements 3-1
3.2.2 Nonattainment Rules 3-2

3.3 Emission Standards 3-3

3.3.1 New Source Performance Standards 3-3
3.3.2 National Emission Standards for Hazardous Air Pollutants 3-4
3.3.3 Florida Rules 3-4
3.3.4 Florida Air Permitting Requirements 3-4

3.4 Source Applicability 3-4

3.4.1 Area Classification 3-4
3.4.2 New Source Review 3-5
3.4.3 Other Clean Air Act Requirements 3-8

TABLE OF CONTENTS

1.0 INTRODUCTION 1-1

2.0 PROJECT DESCRIPTION 2-1

2.1 Site Description 2-1

2.2 Unit No. 2 Repowering Project 2-1

2.2.1 Shutdown of Existing Unit No. 2 Boiler 2-1
2.2.2 Proposed Unit 2-1

2.3 Proposed Source Emissions and Stack Parameters 2-3

2.3.1 Shutdown of Existing Unit No. 2 2-3
2.3.2 Proposed Unit 2-4

2.4 Site Layout, Structures, and Stack Sampling Facilities 2-7

3.0 AIR QUALITY REVIEW REQUIREMENTS AND APPLICABILITY 3-1

3.1 National and State Aaqs 3-1

3.2 New Source Review Requirements 3-1

3.2.1 General Requirements 3-1
3.2.2 Nonattainment Rules 3-2

3.3 Emission Standards 3-3

3.3.1 New Source Performance Standards 3-3
3.3.2 National Emission Standards for Hazardous Air Pollutants 3-4
3.3.3 Florida Rules 3-4
3.3.4 Florida Air Permitting Requirements 3-4

3.4 Source Applicability 3-4

3.4.1 Area Classification 3-4
3.4.2 New Source Review 3-5
3.4.3 Other Clean Air Act Requirements 3-8

TABLE OF CONTENTS

LIST OF TABLES

2-1 Estimated Actual Annual PM/PM_{10}, CO, VOC, Lead and Mercury Emissions for the Existing Hopkins Unit 2 with Latest AP-42 Emission Factors

2-2 Actual SO_2 Emissions for the Existing Hopkins Unit 2 Based on CEMS Data

2-3 Actual NO_x Emissions for the Existng Hopkins Unit 2 Based on CEMS Data

2-4 Stack, Operating, and Emission Data for the Proposed Hopkins Unit 2 Repowering Project for Natural Gas-Firing for Baseload Combined Cycle Operations

2-5 Stack, Operating, and Emission Data for the Proposed Hopkins Unit 2 Repowering Project for Distillate Oil-Firing for Baseload Combined Cycle Operations with Natural Gas Duct Firing

2-6 Stack, Operating, and Emission Data for the Proposed Hopkins Unit 2 Repowering Project for Natural Gas-Firing for Baseload Simple Cycle Operations

2-7 Summary of the Maximum Potential Annual Emissions for the Proposed Hopkins Unit 2 Repowering Project

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

3-2 PSD Significant Emission Rates

3-3 Maximum Emissions Due to the Proposed Hopkins Unit 2 Repowering Project Compared to the PSD Significant Emission Rates

3-4 Summary of Maximum Short-Term Emissions Due to the Proposed Hopkins Unit 2 Repowering Project

LIST OF FIGURES

2-1 Simplified Flow Diagram of the Proposed CT/HRSG and Duct Burner

LIST OF APPENDICES

Appendix A EXPECTED PERFORMANCE AND EMISSION INFORMATION FOR THE COMBUSTION TURBINE AND DUCT BURNER

1.0 INTRODUCTION

The City of Tallahassee proposes to repower the Arvah B. Hopkins Generating Station Unit No. 2, located in Leon County, Florida (see Figure 2.1-1 of the Report for the modification to the Site Certification). The repowering of Unit No. 2 will include the addition of one nominal 188-megawatt (MW) combustion turbine and the permanent shut down of the fossil fuel steam generator for Unit 2. The repowering will enhance the City's electric system reliability and help the City meet the current forecasts of growth in population and electric demand.

The Arvah B. Hopkins Generating Station is an existing generating facility presently comprised of two steam electric generating units (Units 1 and 2), two Westinghouse combustion turbines (CTs) (referred to as GT-1 and GT -2), and two General Electric (GE) LM6000 CTs (referred to as GT -3 and GT -4). GT -3 and GT -4 began operation in 2005.

The proposed combined cycle unit will consist of one GE 7FA CT and associated electric generator, heat recovery steam generator (HRSG), and the existing steam turbine-electric generator. The unit will be equipped with a bypass stack that will be used with natural gas firing only. Together, these facilities are referred to as the "Project".

The proposed CT will use dry low-nitrogen oxides [(NO_x) DLN] combustion technology when operating on natural gas and water injection for NO_x control when operating on distillate fuel oil. The CT/HRSG will be installed with selective catalytic reduction (SCR) to further reduce emissions of NO_x. The HRSG will be equipped with duct burners that will fire natural gas.

The CT will operate a maximum of 8,760 hours per year. The CT will operate up to an equivalent of 3,500 hours per year on distillate fuel oil at full-load operating. Existing transmission and fuel supply facilities are adjacent to the proposed location of the new CT.

The Project will be a minor modification to an existing major air pollution source and requires review under the Department's air construction permit rules. Because the Project is being constructed at a certified site under the Florida Power Plant Siting Act (PPSA), a modification to the site certification is also required. The U.S. Environmental Protection Agency (EPA) and the Florida Department of Environmental Protection (FDEP) have implemented regulations requiring a Prevention of Significant Deterioration (PSD) review for new major sources or major modifications at major sources that increase air emissions above certain threshold amounts. Because the proposed modification will not exceed the major modification threshold amounts, the Project is not subject to PSD review.

Leon County, Florida, has been designated as an attainment or unclassifiable area for all criteria pollutants [i.e., attainment: ozone (O_3); sulfur dioxide (SO_2); carbon monoxide (CO); and nitrogen dioxide (NO_2); unclassifiable: particulate matter with an aerodynamic diameter of 10 microns or less (PM_{10}) and lead] and is a PSD Class II area for PM_{10}, SO_2, and NO_2. Therefore, the preconstruction minor modification review will follow regulations pertaining to such designations.

The air permit application is divided into three major sections:

- Section 1.0 is an introduction to the Project.
- Section 2.0 presents a description of the Project, including air emissions and stack parameters.
- Section 3.0 provides a review of the regulatory requirements applicable to the Project.

2.0 PROJECT DESCRIPTION

2.1 Site Description

The Arvah B. Hopkins Generating Station consists of approximately 232 acres and is presently comprised of two steam electric generating units (Units 1 and 2), two Westinghouse CTs (GT -1 and GT -2), and two GE LM6000 CTs (GT -3 and GT -4). The steam electric units and the CTs use oil, natural gas, and/or liquefied petroleum gas as fuel. Unit 1, which went into service in 1971, is a nominal 75-MW unit. Unit 2, which went into service in 1977, is a nominal 238-MW unit. The existing CT, HC-1, went into service in 1970 and has a nominal generating capacity of approximately 16.5 MW (nominal). The existing CT, GT -2, went into service in 1972 and has a generating capacity of approximately 25 MW (nominal). The LM6000 CTs, GT-3 and GT-4, use natural gas and distillate fuel oil. Both GT-3 and GT-4 went into service in 2005 and have a total generating capacity of approximately 94 MW (net summer rating).

The plant site is bounded by Geddie Road to the west, CSX railroad to the east, State Road 20 to the south and U.S. Highway 90. The plant elevation will be approximately 136 feet above mean sea level (ft-msl). The terrain surrounding the site is gently rolling hills.

2.2 Unit No. 2 Repowering Project

2.2.1 Shutdown of Existing Unit No. 2 Boiler

The City of Tallahassee proposes to repower existing Unit No. 2 with one combined-cycle CT with a duct burner. The repowering Project will result in the permanent shutdown of the Unit No. 2 boiler and replaced with a new combined cycle unit.

2.2.2 Proposed Unit

The proposed CT will be configured as a combined-cycle unit. The combined cycle unit will consist of one GE Frame 7FA CT with an associated HRSG, and the existing Unit 2 steam turbine-electric generator. The CT will use DLN combustion technology when firing natural gas and water injection when firing light oil to minimize NO_x formation. SCR will be installed in the HRSG to further reduce emissions of NO_x. The unit may operate in simple cycle mode; however, the exhaust gases will be routed through the HRSG and SCR system, with the same emissions achieved as those for the combined cycle mode. Natural gas and light oil will be used an alternative fuels.

In the event of a major unplanned forced outage of the HRSG or to the steam turbine, the electrical output associated with the CT would not be available to meet system reliability needs without an alternative to routing steam through the HRSG. To mitigate the system reliability impacts from such a major unplanned forced outage event, an emergency HRSG bypass system be installed as a part of the Project. The bypass stack would be physically inoperable during combined cycle operations. To utilize the bypass stack, the unit would have to be removed from service, a "blanking plate" in the duct would have to be physically removed, and a HRSG blanking plate would have to be installed. Since this would be for emergency bypass use only, the bypass stack would not be equipped with a SCR. During these emergency situations, the City would propose that the unit operate on natural gas only. Compliance with this mode of operation would be demonstrated using the NO_x CEMs without the SCR operating.

Plant performance for the GE 7FA CT was developed for natural gas and oil at 100-, 75-, and 60-percent load and 25, 59, and 95 degrees Fahrenheit (°F) ambient dry bulb temperatures, respectively. Nominal part load percentages herein are relative to 100-percent load without evaporative cooling.

For the CT, the maximum heat input is 1,899 MMBtu/hr (HHV) or 1,711 MMBtu/hr (LHV) when firing natural gas (100-percent capacity, 25°F). For fuel oil firing, the maximum heat input is 2,079 MMBtu/hr (HHV) or 1,961 MMBtu/hr (LHV) (100-percent capacity, 25°F).

The HRSG will be equipped with a duct burner with a maximum heat input of 712 MMBtu/hr (HHV) when firing natural gas at 59 °F. The duct burner has a maximum heat input of 765 MMBtu/hr (HHV) when firing natural gas at 25°F.

The CT will use DLN combustion technology (when firing natural gas) and water injection (when firing distillate oil) to minimize NO_x formation. SCR will be installed in the HRSG to further reduce emissions of NO_x.

The SO_2 emissions will be controlled by the use of low-sulfur fuels. Good combustion practices and clean fuels will also minimize potential emissions of PM, CO, volatile organic compounds (VOC), and other pollutants (e.g., trace metals).

SCR reactors for the unit will be located in the HRSG to provide the proper operating temperature range for the required reaction between ammonia and NOx to achieve the proposed emission rate and to assure the economical operation of the system. The NO_x is reduced by a chemical reaction with the ammonia in the presence of the catalyst. Ammonia is carried by a diluent and injected into the exhaust gas upstream of the catalyst modules. The ammonia reacts with NO_x on the surface of the catalyst to form nitrogen and water.

Natural gas is currently available at the Hopkins facility. As such, there will be minimal additional infrastructure required to support additional natural gas delivery to the site. The Hopkins facility currently has two existing 10,000 bbl diesel storage tanks and two #6 fuel oil tanks (55,000 bbl and 180,000 bbl). The City plans on converting the 180,000 bbl tank to diesel storage. The existing diesel storage tanks and the converted #6 fuel oil tank will be used for the Project, and no new fuel oil tanks will be required.

2.3 Proposed Source Emissions and Stack Parameters

2.3.1 Shutdown of Existing Unit No. 2

The permanent shutdown of the Unit No. 2 boiler will result in emission reductions. These emission reductions are used in the netting analysis for determination of PSD applicability of the Project (see Section 3.0).

To determine the baseline past actual emissions for the existing Unit No. 2, the highest emissions over a consecutive 24-month period in the last 5 years were utilized. This analysis was conducted on a pollutant-by-pollutant basis and is presented in Tables 2-1 through 2-3. The PM/PM_{10}, CO, VOC, and lead emissions are presented in Table 2-1 and are based on fuel usage from the annual operating reports (AORs) reported to the FDEP and the latest AP-42 emission factors for natural gas and fuel oil combustion. These data are presented from 2001 to 2005 and are based on annual emissions estimated for each calendar year. The SO_2 and NO_x emissions are presented in Tables 2-2 and 2-3, respectively, and are based on data recorded by the continuous emission monitor system (CEMS). These data are presented on a monthly basis from March 2001 to February 2006 since the CEMS data are available monthly.

For PM/PM_{10}, VOC, lead, and mercury emissions, the highest annual average emissions occurred over the 24-month period from 2004 to 2005. For CO emissions, the highest annual average emissions occurred over the 24-month period from 2001 to 2002. For SO_2 emissions, the highest annual average emissions from the CEM data occurred over the 24-month period from February 2004 to January 2006. For NO_x emissions, the highest annual average emissions from the CEM data occurred over the 24-month period from May 2003 to April 2005. The annual average emission rates for those years were used to represent the actual annual average emissions for those pollutants.

2.3.2 Proposed Unit

The maximum estimated hourly emission rates of regulated pollutants for combined cycle operation for the CT/HRSG with and without the duct burner when firing natural gas and distillate oil at baseload conditions are presented in Tables 2-4 and 2-5, respectively. The maximum estimated hourly emission rates when the CT is firing distillate oil and the duct burner is firing natural gas are also presented in Table 2-5. The same emission rates will be achieved during simple cycle operation when the exhaust gases are routed through the HRSG and SCR system. The maximum estimated hourly emission rates of regulated pollutants for simple cycle operation when the exhaust gases are routed through the emergency bypass stack, instead of the HRSG and SCR system, are presented in Table 2-6. Only natural gas will be fired when the emergency bypass stack is used. The primary pollutants emitted by the CT/HRSG will be NO_x, CO, SO_2, PM, and VOC.

The maximum estimated hourly emission rates and exhaust information representative of the CT/HRSG and duct burner were determined using the manufacturer's information for the equipment proposed for the Project. The design parameters were provided for operating loads of 100- (baseload), 75-, and 60-percent capacity and for ambient temperatures of 25, 59, and 95°F, respectively. The performance and emissions data for the operating conditions are given in Appendix A for turbine inlet temperatures of 25, 59, and 95°F and various operating conditions (100-percent load and low-load operation applicable for the CT).

As shown in Tables 2-4 through 2-6, the maximum short-term emission rates [pounds per hour (lb/hr)] for base load conditions occur at 25°F operations when the CT has the greatest output and greatest fuel consumption.

The maximum potential annual emissions for the repowered unit are presented in Table 2-7. Annual emissions were based on emissions expected for baseload and ambient temperatures of 59°F. The maximum annual emissions are based on the range of operations that could occur with operating the CT on natural gas and distillate oil and the CT, operating with the duct burners firing natural gas. In addition, the maximum annual emissions were estimated for the CT operating in simple cycle mode with the exhaust to an emergency bypass stack (bypass stack would not be equipped with a SCR).

The annual operation of the repowered unit will be limited so that the net emission increase of all pollutants will be less than the PSD significant emission rates. The allowable annual operation was determined from an analysis of the emissions for various operating scenarios. These scenarios are reflected in the range of operating hours and fuels (natural gas and distillate oil) shown in Table 2-7 for CT operating alone and the CT operating with maximum duct firing. The operating envelope being proposed consists of four parts that are discussed below:

1. CT operation mode when firing natural gas in combined cycle or simple cycle mode with the exhaust gases routed through the HRSG and SCR system is not limited (see Operating Scenarios A and E in Table 2-7). CT operation in simple cycle mode with the emergency bypass stack will be limited to natural gas firing. The emissions during this operational mode are not higher than those in the combined cycle mode for any pollutant except for NO_x. NO_x emissions in this mode are not limiting based on the netting analysis described in Section 3.0 and shown as Operating Scenario E in Table 2-7.
2. Duct firing with natural gas is proposed to be limited to 2,598,800 MMBtu/yr (HHV), which is equivalent to 3,650 hours at the maximum duct firing rate of 712 MMBtu/hr (see Operating Scenario B).
3. The maximum amount of distillate oil firing in the CT is proposed to be limited to 6,926,500 MMBtu/yr, which is equivalent to 3,500 hours at full load as shown in Table 2-7 as Operating Scenarios C and D.

The potential annual emissions are based on the 59°F turbine inlet temperature at 100-percent load condition, which is conservative since the annual average temperatures for the Tallahassee area are slightly higher than 70°F. Higher turbine inlet temperatures result in lower turbine performance and lower mass emissions. The conservative nature of the turbine inlet temperature combined with a 100-percent capacity factor (i.e., 8,760 hours per year at full load) result in worst-case emissions estimates.

Emission factors for hazardous air pollutants (HAPs) were evaluated based on the revised AP-42 emission factors, the EPA Combustion Turbine Emissions Database, and the CT Maximum Achievable Control Technology (MACT) standards. The HAP emissions are based on emission factors from the April 2000 revision of EPA's AP-42 emission factors for large stationary CTs. Summaries of the emission factors and emissions for light oil-firing and gas-firing are presented in Appendix A.

The MACT standard in 40 CFR, Subpart YYYY, is potentially applicable to the Project. The HAPs emissions from the Project will be less than 10 tons per year (TPY) for any single HAP and less than 25 TPY for all HAPs. However, the Hopkins Plant is a major source of HAP emissions since emissions exceed 10 TPY of a single HAP and exceed 25 TPY for all HAPs and will remain a major source of HAPs after the repowering project. Since low-sulfur light oil is proposed to be fired in the proposed CT, the proposed CT is defined as "stationary diffusion flame oil-fired combustion turbines" under the Subpart YYYY requirements. The Project, combined with two other CTs at the Hopkins facility, would have the potential for an aggregate total potential of 1,000 hours or more of oil firing during any calendar year. Actual applicability of Subpart YYYY is based on actual oil fuel used in a calendar year. The proposed Project will be required to demonstrate compliance with the CT MACT of 91-parts per billion by volume, dry (ppbvd) formaldehyde, corrected to 15-percent oxygen, if the aggregate 1,000 hours per year is exceeded. Based on the applicability of Subpart YYYY, compliance will be determined upon initial operation and annually (40 CFR Part 63, Section 63.6120, Table 3).

An emission factor for toluene of 33 pounds (lb)/10^{12} British thermal units (Btu) for natural gas firing, was developed from the data in the EPA Combustion Turbine Emissions Database. This factor is based on the median value for loads greater than 80 percent. Similar to formaldehyde emission factors, there are no confirmed test data of toluene emissions from F Class turbines. The recent EPA emission factor, which is based on much smaller turbines than those proposed for the Project, suggests toluene emissions from gas turbines of 130 lb/10^{12} Btu when firing natural gas at loads greater than 80 percent. For all loads, the average and median EPA factors are 94 and 19 lb/10^{12} Btu, respectively. Since the median emission factor is about 4 to 5 times lower than the average factor, this clearly points to the large range in toluene emissions and how the individual CT characteristics can influence the results.

The emission factors for many of the other HAPs were developed by EPA in a manner similar to toluene. For these HAPs, fewer data are available and are also considered not representative of state-of-the-art DLN combustion systems. The use of AP-42 emission factors for HAPs is considered to provide conservative estimates of emissions.

The GE 7FA CT with SCR will experience excess emissions during the short startup and shutdown periods for NO_x and may experience excess emissions for other pollutants. The conservative turbine inlet temperature combined with the assumption of 100-percent capacity factor provides maximum potential emissions that would envelope operation including any excess emissions from startups and shutdowns.

2.4 Site Layout, Structures, and Stack Sampling Facilities

A site plan of the proposed Project is presented in Figure 2.1-2 (see the Report for the modification to the Site Certification) and a process flow diagram is presented in Figure 2-1. Stack sampling facilities will be constructed in accordance to Rule 62-297.310(6), F.A.C.

TABLE 2-1
ESTIMATED ACTUAL ANNUAL PM/PM_{10}, CO, VOC, LEAD, AND MERCURY EMISSIONS
FOR THE EXISITNG HOPKINS UNIT 2 WITH LATEST AP-42 EMISSION FACTORS

Pollutant	Units	Emissions 2001	2002	2003	2004	2005	Maximum 2-year Period
Total Emissions							
PM	TPY	32.2	26.3	111.1	126.2	146.5	136.3
PM_{10}	TPY	24.3	20.2	79.2	90.4	104.7	97.5
CO	TPY	233.8	248.4	181.2	252.8	194.1	241.1
VOC	TPY	16.3	17.0	16.6	21.7	17.7	19.7
Lead	TPY	0.0046	0.0040	0.017	0.019	0.018	0.019
Mercury	TPY	0.00032	0.00026	0.00127	0.00140	0.00135	0.0014
Residual Oil (Grade 6) [a]							
PM	TPY	27.2	20.9	108.2	121.8	143.4	
PM_{10}	TPY	19.3	14.8	76.4	86.0	101.6	
CO	TPY	11.0	8.4	54.5	59.1	57.8	
VOC	TPY	1.7	1.3	8.3	9.0	8.8	
Lead	TPY	0.0033	0.0025	0.016	0.018	0.017	
Mercury	TPY	0.00025	0.00019	0.00123	0.00134	0.00131	
S content	percent	1	1	0.73	0.77	1	
Fuel usage	1,000 gal/yr	4,383.20	3,367.20	21,799.08	23,658.40	23,109.50	
Natural Gas [b]							
PM	TPY	5.0	5.4	2.9	4.4	3.1	
PM_{10}	TPY	5.0	5.4	2.9	4.4	3.1	
CO	TPY	222.9	239.9	126.7	193.7	136.3	
VOC	TPY	14.6	15.7	8.3	12.7	8.9	
Lead	TPY	0.0013	0.0014	0.0008	0.0012	0.0008	
Mercury	TPY	0.00007	0.00007	0.00004	0.00006	0.00004	
Fuel usage	million cubic ft/yr	5,306.81	5,712.80	3,016.04	4,611.60	3,245.20	

[a] Emission factors for residual fuel oil (AP-42, Section 1.3, 9/98)

PM	lb/1,000 gal	(9.19 x S) + 3.22	(Filterable only)
PM_{10}	lb/1,000 gal	5.9 x [(1.12 x S) + 0.37]	(Filterable only)
CO	lb/1,000 gal	5.0	
VOC	lb/1,000 gal	0.76	
Lead	lb/1,000 gal	0.00151	
Mercury	lb/1,000 gal	0.000113	

[b] Emission factors for natural gas (AP-42, Section 1.4, 3/98)

PM	lb/mmcf	1.9	(Filterable only)
PM_{10}	lb/mmcf	1.9	(Filterable only)
CO	lb/mmcf	84	
VOC	lb/mmcf	5.5	
Lead	lb/mmcf	0.0005	
Mercury	lb/mmcf	0.000026	

TABLE 2-2
ACTUAL SO_2 EMISSIONS FOR THE EXISTING HOPKINS UNIT 2
BASED ON CEMS DATA

		SO_2 Emissions			
		Tons/month (TPM)			Tons/year (TPY) Average 24 months Consecutive
Year	Month	Oil	Gas	TOTAL	
Maximum				438	1642
2001	Mar	0	0	0	NA
	Apr	0	0.06	0.06	NA
	May	0	0.28	0.28	NA
	Jun	0	0.27	0.27	NA
	Jul	0	0.31	0.31	NA
	Aug	15.93	0.28	16.21	NA
	Sep	13.64	0.23	13.87	NA
	Oct	0	0	0	NA
	Nov	0	0	0	NA
	Dec	0	0.03	0.03	NA
2002	Jan	36.95	0.07	37.02	NA
	Feb	0	0	0	NA
	Mar	0	0.03	0.03	NA
	Apr	0	0.22	0.22	NA
	May	87.61	0.13	87.74	NA
	Jun	4.42	0.22	4.64	NA
	Jul	0	0.26	0.26	NA
	Aug	0	0.26	0.26	NA
	Sep	4.9	0.2	5.1	NA
	Oct	51.44	0.07	51.51	NA
	Nov	24.64	0.17	24.81	NA
	Dec	0	0.18	0.18	NA
2003	Jan	90.14	0.07	90.21	NA
	Feb	2.31	0.01	2.32	168
	Mar	84.51	0.11	84.62	210
	Apr	0	0.03	0.03	210
	May	189.66	0.08	189.74	305
	Jun	181.58	0.09	181.67	395
	Jul	183.92	0.1	184.02	487
	Aug	212.51	0.08	212.59	585
	Sep	112.8	0.14	112.94	635
	Oct	59.11	0.2	59.31	665
	Nov	0	0.01	0.01	665
	Dec	194.67	0.02	194.69	762
2004	Jan	135.3	0.04	135.34	811
	Feb	70.44	0.16	70.6	846
	Mar	84.04	0.17	84.21	889
	Apr	66.43	0.17	66.6	922
	May	123.79	0.19	123.98	940
	Jun	134.84	0.16	135	1005
	Jul	155.65	0.12	155.77	1083
	Aug	170.1	0.11	170.21	1168
	Sep	183.31	0.08	183.39	1257
	Oct	194.54	0.09	194.63	1328
	Nov	44.04	0.08	44.12	1338
	Dec	128.77	0.03	128.8	1402
2005	Jan	115.66	0.02	115.68	1415
	Feb	150.79	0.01	150.8	1489
	Mar	29.15	0.01	29.16	1462
	Apr	265.29	0	265.29	1594
	May	12.7	0.21	12.91	1506
	Jun	34.93	0.18	35.11	1433
	Jul	101.54	0.18	101.72	1391
	Aug	276.69	0.09	276.78	1424
	Sep	103.71	0.14	103.85	1419
	Oct	-	-	97.0	1438
	Nov	-	-	29.7	1453
	Dec	-	-	438.4	1575
2006	Jan	-	-	270.2	1642
	Feb	-	-	14.2	1614

TABLE 2-3
ACTUAL NO_x EMISSIONS FOR THE EXISTING HOPKINS UNIT 2
BASED ON CEMS DATA

Year	Month	NO_x Emissions Tons/month (TPM) TOTAL	NO_x Emissions Tons/year (TPY) Average 24 months Consecutive
Maximum		131	843
	Mar	0.00	NA
	Apr	22.43	NA
	May	91.98	NA
	Jun	83.45	NA
	Jul	99.49	NA
	Aug	131.33	NA
	Sep	70.79	NA
	Oct	0.93	NA
	Nov	0.00	NA
	Dec	7.62	NA
2002	Jan	36.00	NA
	Feb	0.00	NA
	Mar	11.55	NA
	Apr	99.18	NA
	May	71.81	NA
	Jun	56.04	NA
	Jul	73.79	NA
	Aug	75.77	NA
	Sep	60.50	NA
	Oct	39.19	NA
	Nov	45.23	NA
	Dec	30.12	NA
2003	Jan	52.94	NA
	Feb	3.40	582
	Mar	52.18	608
	Apr	3.72	599
	May	76.00	591
	Jun	96.32	597
	Jul	88.72	592
	Aug	99.95	576
	Sep	79.38	580
	Oct	72.05	616
	Nov	1.31	616
	Dec	81.19	653
2004	Jan	60.74	666
	Feb	60.16	696
	Mar	79.11	729
	Apr	78.72	719
	May	124.15	745
	Jun	101.11	768
	Jul	79.76	771
	Aug	79.86	773
	Sep	85.54	785
	Oct	95.74	814
	Nov	24.06	803
	Dec	44.57	810
2005	Jan	48.36	808
	Feb	47.05	830
	Mar	10.67	809
	Apr	72.16	843
	May	44.70	828
	Jun	46.56	803
	Jul	81.39	799
	Aug	114.19	806
	Sep	46.85	790
	Oct	2.07	755
	Nov	0.61	755
	Dec	14.10	721
2006	Jan	1.32	691
	Feb	0.67	662

TABLE 2-4
STACK, OPERATING, AND EMISSION DATA FOR THE PROPOSED HOPKINS UNIT 2 REPOWERING PROJECT
FOR NATURAL GAS-FIRING FOR BASELOAD COMBINED CYCLE OPERATIONS

Parameter	Units	Natural Gas-Firing[a]					
		CT Only			CT with Duct Burner on Gas		
		25 °F	59 °F	95 °F	25 °F	59 °F	95 °F
Combustion Turbine Performance							
Net power output (MW)	MW	187.8	174.4	160.3	187.8	174.4	160.3
Net heat rate	Btu/kWh, LHV	9,110	9,270	9,495	9,110	9,270	9,495
	Btu/kWh, HHV	10,112	10,290	10,539	10,112	10,290	10,539
Heat Input	MMBtu/hr, LHV	1,711	1,617	1,522	1,711	1,617	1,522
	MMBtu/hr, HHV	1,899	1,795	1,689	1,899	1,795	1,689
Relative Humidity	%	87	78	50	87	78	50
Fuel heating value	Btu/lb, LHV	20,714	20,714	20,714	20,714	20,714	20,714
	Btu/lb, HHV	22,993	22,993	22,993	22,993	22,993	22,993
Duct Burner							
Heat Input	MMBtu/hr, LHV	0.0	0.0	0.0	765	712	663
	MMBtu/hr, HHV	0.0	0.0	0.0	689	641	597
CT/HRSG Stack Data							
Height	ft	150	150	150	150	150	150
Diameter	ft	18	18	18	18	18	18
100 Percent Load							
Temperature (°F)	°F	203	202	201	189	188	190
Velocity (ft/sec)	ft/sec	70.9	67.0	63.2	70.4	66.5	63.0
Maximum Hourly Emissions							
SO_2	lb/hr	10.47	9.90	9.32	14.7	13.8	13.0
PM/PM_{10}	lb/hr	11.1	11.0	10.9	21.1	20.3	19.6
NO_x	lb/hr	34.3	32.4	30.5	47.8	45.0	42.2
	ppmvd @ 15% O_2	5	5	5	5	5	5
CO	lb/hr	41.7	39.1	36.2	96.8	90.3	83.9
	ppmvd	12.0	12.0	12.0	28.6	28.5	28.6
	ppmvd @ 15% O_2	10.0	9.9	9.7	16.8	16.7	16.5
VOC (as methane)	lb/hr	7.52	7.12	6.72	16.70	15.66	14.67
	ppmvw	3.50	3.50	3.50	8.64	8.66	8.76
	ppmvd @ 15% O_2	3.15	3.16	3.16	5.67	5.71	5.80
Lead	lb/hr	NA	NA	NA	NA	NA	NA
Sulfuric Acid Mist	lb/hr	1.05	0.99	0.93	1.89	1.77	1.66

[a] Refer to Appendix A for detailed information on basis of pollutant emission rates and operating data.
Includes simple cycle operation with exhaust gases routed to the HRSG and SCR system.

Source: GE, 2006.

TABLE 2-5
STACK, OPERATING, AND EMISSION DATA FOR THE PROPOSED HOPKINS UNIT 2 REPOWERING PROJECT
FOR DISTILLATE OIL-FIRING FOR BASELOAD COMBINED CYCLE OPERATIONS WITH NATURAL GAS DUCT FIRING

		Distillate Oil-Firing [a]					
		CT Only			CT with Duct Burner on Gas		
Parameter	Units	25 °F	59 °F	95 °F	25 °F	59 °F	95 °F
Combustion Turbine Performance							
Power output (MW)	MW	198.9	187.9	172.4	198.9	187.9	172.4
Heat rate	Btu/kWh, LHV	9,860	9,935	10,090	9,860	9,935	10,090
	Btu/kWh, HHV	10,452	10,531	10,695	10,452	10,531	10,695
Heat Input	MMBtu/hr, LHV	1,961	1,867	1,740	1,961	1,867	1,740
	MMBtu/hr, HHV	2,079	1,979	1,844	2,079	1,979	1,844
Relative Humidity	%	87	78	50	87	78	50
Fuel heating value	Btu/lb, LHV	18,300	18,300	18,300	18,300	18,300	18,300
	Btu/lb, HHV	19,398	19,398	19,398	19,398	19,398	19,398
Duct Burner							
Heat Input	MMBtu/hr, LHV	0.0	0.0	0.0	765	712	663
	MMBtu/hr, HHV	0.0	0.0	0.0	689	641	597
CT/HRSG Stack Data							
Height	ft	150	150	150	150	150	150
Diameter	ft	18	18	18	18	18	18
100 Percent Load							
Temperature (oF)	°F	248	248	247	206	204	201
Velocity (ft/sec)	ft/sec	79.5	75.1	70.3	75.8	71.4	66.6
Maximum Hourly Emissions							
SO_2	lb/hr	107	102	95	111	106	99
PM/PM_{10}	lb/hr	38.7	37.6	36.2	48.7	47.0	44.9
NOx	lb/hr	81.4	77.5	72.2	108.4	102.6	95.6
	ppmvd @ 15% O2	10.0	10.0	10.0	10.0	10.0	10.0
CO	lb/hr	87.8	82.2	76.1	142.9	133.4	123.8
	ppmvd	25.0	25.0	25.0	41.9	41.8	41.9
	ppmvd @ 15% O2	17.7	17.4	17.3	21.4	21.2	21.1
VOC (as methane)	lb/hr	7.89	7.46	6.99	17.1	16.0	14.9
	ppmvw	3.5	3.5	3.5	7.6	7.5	7.5
	ppmvd @ 15% O2	2.8	2.8	2.8	5.2	5.2	5.3
Lead	lb/hr	0.029	0.028	0.026	0.029	0.028	0.026
Sulfuric Acid Mist	lb/hr	21.4	20.4	19.0	22.3	21.2	19.7

[a] Refer to Air Construction Permit Application (Appendix 10.1.5) for detailed information on basis of pollutant emission rates and operating data. Includes simple cycle operation with exhaust gases routed to the HRSG and SCR system.

Source: GE, 2006

TABLE 2-6
STACK, OPERATING, AND EMISSION DATA FOR THE PROPOSED HOPKINS UNIT 2 REPOWERING PROJECT
FOR NATURAL GAS-FIRING FOR BASELOAD SIMPLE CYCLE OPERATIONS

		Natural Gas-Firing[a]		
		CT Only		
Parameter	Units	25 °F	59 °F	95 °F
Combustion Turbine Performance				
Net power output (MW)	MW	187.8	174.4	160.3
Net heat rate	Btu/kWh, LHV	9,110	9,270	9,495
	Btu/kWh, HHV	10,112	10,290	10,539
Heat Input	MMBtu/hr, LHV	1,711	1,617	1,522
	MMBtu/hr, HHV	1,899	1,795	1,689
Relative Humidity	%	87	78	50
Fuel heating value	Btu/lb, LHV	20,714	20,714	20,714
	Btu/lb, HHV	22,993	22,993	22,993
CT/Bypass Stack Data				
Height	ft	150	150	150
Diameter	ft	18	18	18
100 Percent Load				
Temperature (°F)	°F	1,081	1,114	1,144
Velocity (ft/sec)	ft/sec	164.9	159.4	153.3
Maximum Hourly Emissions				
SO_2	lb/hr	10.5	9.90	9.32
PM/PM_{10}	lb/hr	9.0	9.0	9.0
NO_x	lb/hr	61.8	58.4	55.0
	ppmvd @ 15% O2	9.0	9.0	9.0
CO	lb/hr	41.7	39.1	36.2
	ppmvd	12.0	12.0	12.0
	ppmvd @ 15% O2	10.0	9.9	9.7
VOC (as methane)	lb/hr	7.52	7.12	6.72
	ppmvw	3.50	3.50	3.50
	ppmvd @ 15% O2	3.15	3.16	3.16
Lead	lb/hr	NA	NA	NA
Sulfuric Acid Mist	lb/hr	1.05	0.99	0.93

[a] Refer to Appendix A for detailed information on basis of pollutant emission rates and operating data.

Source: GE, 2006.

TABLE 2-7
SUMMARY OF MAXIMUM POTENTIAL ANNUAL EMISSIONS
FOR THE PROPOSED HOPKINS UNIT 2 REPOWERING PROJECT

Pollutant	Maximum Potential Annual Emissions (TPY) for CT and Duct Burner Operating Scenarios [a]				
	A	B	C	D	E
SO_2	43	51	211.7	211.7	43.4
PM	48	65	111.8	111.8	39.4
PM_{10}	48	65	111.8	111.8	39.4
NO_x	142	165	244	266	256
CO	171	265	340	340	171
VOC (as methane)	31.2	46.8	47.4	47.4	31.2
Sulfuric Acid Mist	4.3	5.8	39.7	39.7	4.3
Lead	0.00E+00	0.00E+00	4.85E-02	4.85E-02	0.00E+00
Mercury	0.00E+00	0.00E+00	4.16E-03	4.16E-03	0.00E+00

[a] Based on the following hours of operation for each operating scenario:

	A	B	C	D	E
Combined Cycle Operation					
CT, natural gas-firing	8,760	5,110	1,610	5,110	0
CT and duct burner, natural gas-firing	0	3,650	3,650	150	0
CT, fuel oil-firing	0	0	3,500	0	0
CT, fuel oil-firing; duct burner, natural gas-firin	0	0	0	3,500	0
Simple Cycle Operation					
CT, natural gas-firing	0	0	0	0	8,760

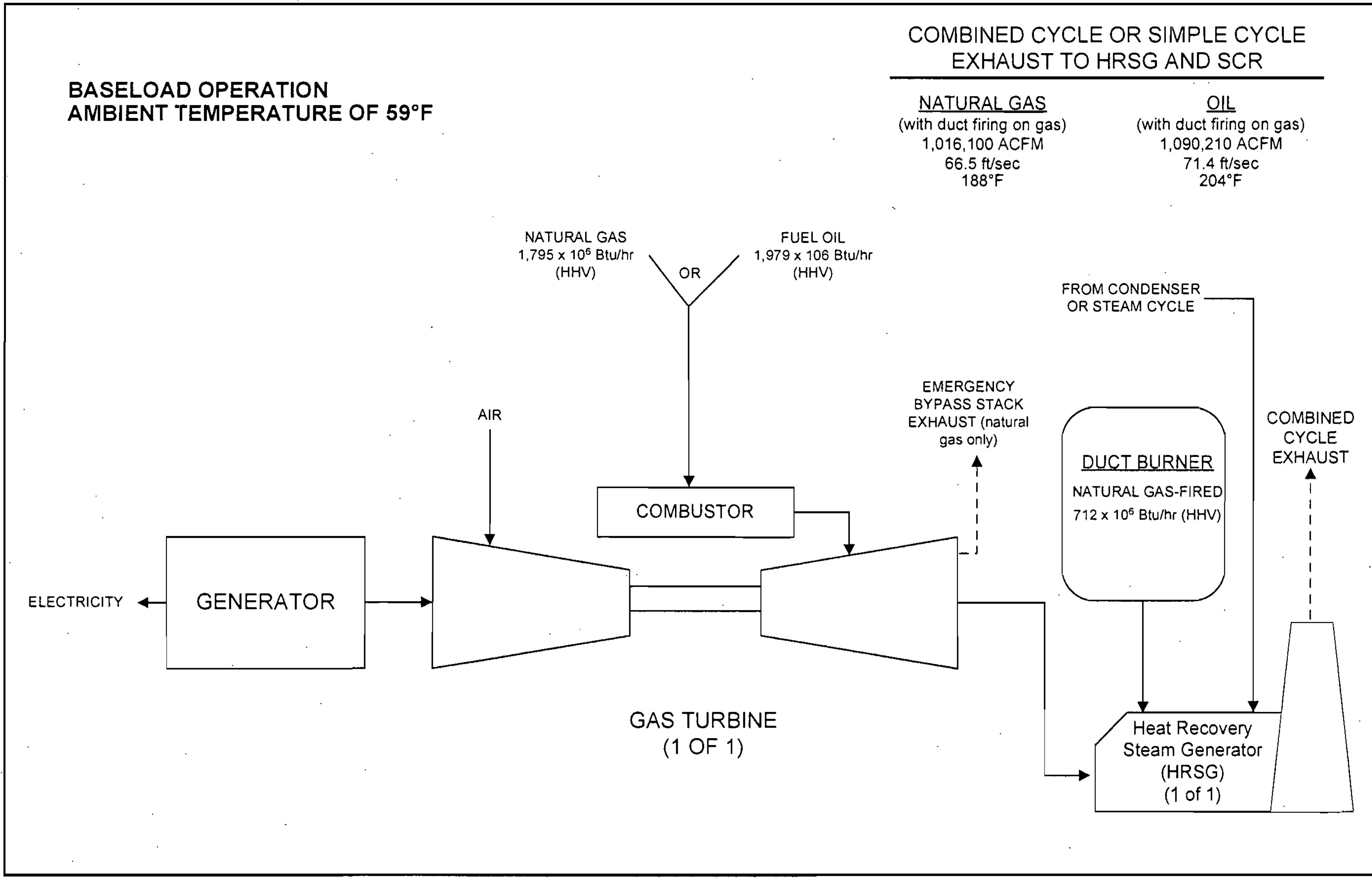

Figure 2-1
Process Flow Diagram
Baseload Operation, Ambient Temperature of 59°F
Unit No. 2 Repowering Project
0637522/4.4/Figure 2-1.vsd

Process Flow Legend
Solid/Liquid →
Gas - - - →

CITY OF TALLAHASSEE

3.0 AIR QUALITY REVIEW REQUIREMENTS AND APPLICABILITY

The following discussion pertains to the federal, State, and local air regulatory requirements and their applicability to the Hopkins Unit 2 Repowering Project. These requirements must be satisfied before the proposed facility can begin operation.

3.1 National and State Aaqs

The existing applicable national and State of Florida local AAQS are presented in Table 3-1. Primary national AAQS were promulgated to protect the public health with an adequate margin of safety, and secondary national AAQS were promulgated to protect the public welfare from any known or anticipated adverse effects associated with the presence of pollutants in the ambient air. Areas of the country in compliance with AAQS are designated as attainment areas. New sources to be located in or near these areas may be subject to more stringent air permitting requirements.

3.2 New Source Review Requirements

3.2.1 General Requirements

Under federal and State of Florida PSD review requirements, all major new or modified sources of air pollutants regulated under the Clean Air Act (CAA) must be reviewed, and a pre-construction permit issued. Florida's State Implementation Plan (SIP), which contains PSD regulations, has been approved by EPA; therefore, PSD approval authority has been granted to FDEP.

A "major facility" is defined as any one of 28 named source categories that have the potential to emit 100 TPY or more or any other stationary facility that has the potential to emit 250 TPY or more of any pollutant regulated under CAA. "Potential to emit" means the capability, at maximum design capacity, to emit a pollutant after the application of control equipment.

PSD review is used to determine whether significant air quality deterioration will result from the new or modified facility. The State of Florida's PSD regulations are found in Rule 62-212.400, F.A.C. Major new facilities are required to undergo the following analysis related to PSD for each pollutant emitted in significant amounts (see Table 3-2):

1. Control technology review,
2. Source impact analysis,
3. Air quality analysis (monitoring),
4. Source information, and
5. Additional impact analyses.

In addition to these analyses, a new facility also must be reviewed with respect to GEP stack height regulations.

For new minor sources or minor modification made at a major source, the new source review requirements under the PSD regulations do not apply. Instead, an air construction permit must be obtained under the general preconstruction review requirements in Rule 62-212.300, F.A.C., and for units added at a certified site for which conditions of certification are issued under the Power Plant Siting Act.

EPA has promulgated regulations providing that certain increases above an air quality baseline concentration level of SO_2, PM_{10}, and NO_2 concentrations that would constitute significant deterioration. The EPA class designations and allowable PSD increments are presented in Table 3-1. The State of Florida has adopted the EPA class designations and allowable PSD increments for SO_2, PM_{10}, and NO_2.

Because this Project will be a minor modification at a major source, the new source review requirements under the PSD regulations do not apply. As a result, the Project will not be required to undergo PSD review. The Project is still obligated to comply with FDEP regulations in submitting an air construction permit application.

3.2.2 Nonattainment Rules

FDEP has nonattainment provisions (Rule 62-212.500, F.A.C.) that apply to all major new sources facilities located in a nonattainment area. In addition, for major facilities that are located in an attainment or unclassifiable area, the nonattainment review procedures apply if the source or modification is located within the area of influence of a nonattainment area. The Hopkins Plant is located in Leon County, which is classified as an attainment or unclassifiable area for all criteria pollutants. Therefore, nonattainment new source review requirements are not applicable.

3.3 Emission Standards

3.3.1 New Source Performance Standards

The NSPS are a set of national emission standards that apply to specific categories of new sources. As stated in the 1977 CAA Amendments, these standards "shall reflect the degree of emission limitation and the percentage reduction achievable through application of the best technological system of continuous emission reduction the Administrator determines has been adequately demonstrated."

The Hopkins Unit 2 Repowering Project will be subject to one or more NSPS. The following sections describe NSPS potentially applicable to the project.

Combustion Turbine

The existing applicable federal New Source Performance Standards (NSPS) for the combustion turbine are those promulgated by EPA for stationary gas turbines. These NSPS (40 CFR Part 60, Subpart GG) establish emission-limiting standards for NO_x and SO_2. The applicable NSPS are:

- NO_x - 75 ppmvd corrected to 15-percent O_2 and heat rate plus adjustment to fuel-bound nitrogen, and
- SO_2 - no more than 0.8-percent sulfur in the fuel.

However, on February 18, 2005, EPA proposed new NSPS for Stationary Combustion Turbines that will commence construction after February 18, 2005. These NSPS, Subpart KKKK, eventually will replace Subpart GG and Da for combustion turbines in combined cycle mode with duct burners. When finalized, the Subpart KKKK requirements will supersede the Subpart GG requirements and apply to units with a gross capacity of greater than 1 MW. The proposed Subpart KKKK requirements that would apply to the Project when finalized by EPA are applicable to combustion turbines greater than 30 MW. The NOx emissions are limited to 0.39 lb/MW-hr for gas-firing and 1.2 lb/MW-hr for light oil firing. Based on a typical simple cycle CT efficiency, these emission rates are approximately equivalent to 10 ppmvd corrected to 15-percent O_2 when firing natural gas and 30 ppmvd corrected to 15-percent O2 when firing light oil. For SO_2 emissions, the proposed Subpart KKKK requirements limit emissions to 0.58 lb/MW-hr or a fuel sulfur content of 0.05 percent. There are no emission limits in Subpart KKKK for particulate matter.

Duct Burner

The applicable federal NSPS for the duct burner are those promulgated by EPA on February 27, 2006 under 40 CFR Part 60, Subpart Da, for electric utility steam generating units capable of combusting more than 250 MMBtu/hr of fossil fuel for which construction is commenced after September 18, 1978. EPA finalized new NSPS for these units that establish emission-limiting standards for PM, NO_x and SO_2 (PM- 0.015 lb/MMBtu; NO_x- 1.0 lb/MW-hr; SO_2- 1.4 lb/MW-hr; regardless of the type of fuel burned). However, HRSG and duct burners subject to the proposed NSPS, Subpart KKKK, would be exempt from the requirements of NSPS, Subpart Da.

3.3.2 National Emission Standards for Hazardous Air Pollutants

As discussed in Section 2.3, EPA has promulgated MACT standards for combustion turbines. The MACT standard limits formaldehyde emissions to 91 ppbvd corrected to 15-percent O_2, which is equivalent to about 220 lb/10^{12} Btu when firing natural gas and about 240 lb/10^{12} Btu when firing light oil (see Appendix A). The MACT standard could potentially apply to the Project, if during any calendar year oil use exceeds an aggregate of 1,000 hours for all turbines on the site.

3.3.3 Florida Rules

The FDEP has adopted the EPA NSPS by reference in Rule 62-204.800(8): Subsection (b)39 for stationary gas turbines and Subsection (b)2 for the duct burners. Therefore, the facility is required to meet the same emissions, performance testing, monitoring, reporting, and record keeping as those described in Subsection 3.3.1. FDEP periodically updates the NSPS that are adopted by reference. FDEP has authority for implementing NSPS requirements in Florida.

3.3.4 Florida Air Permitting Requirements

The FDEP regulations require any new source to obtain an air permit prior to construction. Minor modifications to major sources must comply with NSPS, National Emission Standards for Hazardous Air Pollutants (NESHAP), Permit to Construct, and Permit to Operate. The requirements for construction permits and approvals are contained in Rules 62-4.030, 62-4.050, 62-4.210, and 62-210.300(1), F.A.C. Specific emission standards are set forth in Chapter 62-296, F.A.C.

3.4 Source Applicability

3.4.1 Area Classification

The Project is located in Leon County, which has been designated by EPA and FDEP as an attainment area (includes unclassifiable) for all criteria pollutants. Leon County and surrounding counties are designated as PSD Class II areas for SO_2, PM_{10}, and NO_2. The site is located approximately 28 kilometers (km) from the PSD Class I area of the Bradwell Bay National Wilderness Area (NWA) and 38 km from the closest part of the PSD Class I area of the St. Marks NWA.

3.4.2 New Source Review

Pollutant Applicability

The existing Hopkins Generating Station is considered to be a major facility because the emissions of several regulated pollutants are estimated to exceed 100 TPY, and the emissions units are one of the 28 listed major source categories under the PSD rules.

The City of Tallahassee proposes to repower the existing 238-MW Unit No. 2 with the addition of one nominal 188-MW combined-cycle unit and the permanent shut down of the fossil fuel steam generator for Unit 2. The emissions of each unit have been previously described. A summary of the maximum potential annual emissions for the repowered Unit 2 with the emission reductions due to the shutdown of the existing Unit 2 boiler is presented in Table 3-3.

The PSD definition of a net emission increase consists of two additive components as follows:

- Any increase in actual emissions from a particular physical change or change in method of operation at a stationary source; and
- Any other increase and decreases in actual emissions at the source that are contemporaneous with the particular change and are otherwise creditable.

The first component narrowly includes only the emissions increases associated with a particular change at the source (the proposed CT emission). The second component more broadly includes all contemporaneous, source-wide (occurring anywhere at the entire source), creditable emission increases and decreases. For the Project, the shutdown of Unit No. 2 represents creditable emission decreases.

As shown in Table 3-3, potential annual emissions from the Hopkins Unit 2 Repowering Project, together with the emissions reductions due to the shutdown of the existing Unit 2 boiler, will not trigger PSD review for any regulated pollutant.

The maximum potential annual emissions were based the following operational scenarios at a turbine inlet temperature of 59 °F:

- CT operation when firing natural gas in combined cycle or simple cycle mode with exhaust gases routed through the HRSG and SCR system for 8,760 hours per year operation of the CT at full load for all pollutants except NO_x. For NO_x, the maximum annual emissions were based on the CT operation in simple cycle mode with exhaust gases routed through the emergency bypass stack for 8,760 hours per year operation of the CT at full load at full load. Only natural gas will be fired in this mode.
- Maximum duct firing with natural gas of 2,598,800 MMBtu/yr (HHV), which is equivalent to 3,650 hours/year operation at the maximum hourly duct firing rate.
- Maximum distillate oil-firing in the CT of 6,926,500 MMBtu/yr (HHV), which is equivalent to 3,500 hours of the CT at full load.

A summary of the maximum short-term emission proposed for the repowered unit is presented in Table 3-4.

Therefore, under PSD regulations, the Project is classified as a minor modification at a major source. As a result, the new source review requirements under the PSD regulations do not apply and the Project will not be required to undergo PSD review. Instead, the Project will be required to be reviewed under the general preconstruction review requirements in Rule 62-212.300, F.A.C., and subject to a final order issued pursuant to the PPSA.

Emission Standards

The applicable NSPS for the CTs is 40 CFR Part 60, Subpart GG, and the applicable NSPS for the duct burner is 40 CFR Part 60, Subpart Da. These NSPS are being replaced by Subpart KKKK.

For this Project, the NO_x emissions from the CT will be less than 0.2 lb/MW-hr for gas-firing and 0.42 lb/MW-hr for light oil firing for the combined cycle and simple cycle operations when the exhaust gases are routed to the HRSG and SCR system. For simple cycle operation when the exhaust gases are routed to the bypass stack, the NOx emissions from combustion turbine will be approximately 0.3 lb/MW-hr for gas-firing. For SO_2, the Project's emissions will be limited to a fuel sulfur content of 0.05 percent.

The NESHAPs Subpart YYYY may potentially apply to the Project. Information available from the EPA's emission database indicate that the Project will meet the proposed MACT of 91 ppbvd corrected to 15-percent O_2 for formaldehyde.

As previously discussed, the applicable federal NSPS for the duct burner are those promulgated by EPA on February 27, 2006, under 40 CFR Part 60, Subpart Da, which establish emission-limiting standards for PM, NO_x, and SO_2. EPA finalized new NSPS for these units that establish emission-limiting standards for PM, NO_x, and SO_2. However, HRSG and duct burners subject to the proposed NSPS, Subpart KKKK, such as the duct burner proposed for this Project would be exempt from the requirements of NSPS, Subpart Da. The emission limits proposed for the Project will be well less than the limits in Subpart Da.

Excess Emissions

The start-up and shutdown and fuel changes in combined cycle operation will require an excess emission allowance greater than 2 hours provided under the FDEP rules. During cold start-up, the operating load of the CTs is limited by the amount of steam that can be accepted by the steam turbine requiring low-load operation for longer than 2 hours and resulting in excess emissions during these periods. Major tuning sessions of the DLN combustors will also result in conditions where excess emissions may occur. An excess emission allowance is requested for this Project similar to the allowance authorized by the FDEP for the City's Purdom Repowering Project. The combined cycle unit associated with this facility has a similar steam turbine that receives steam during start-up. The proposed condition follows:

> Excess emissions resulting from startup, shutdown, malfunction, or fuel switching shall be permitted providing best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed the following in any 24-hour period: a total of six hours during any day including a cold startup; a total of four hours during any day that includes a hot startup; and a total of two hours during days not including a hot or cold startup. A cold startup is startup after the combined cycle unit has been down for more than 48 hours. A hot startup is startup after the combined cycle unit has been down for 48 hours or less.

In addition, excess emissions resulting from a major DLN/water injection tuning session without SCR operation shall be permitted provided the tuning session is performed in accordance with the manufacturer's specifications and in no case shall exceed 72 hours in any calendar year. A "major tuning session" would occur after a combustor change-out, a major repair to a combustor, or other similar circumstances. Prior to performing any major tuning session, the permittee shall provide the Compliance Authority with an advance notice that details the activity and proposed tuning schedule. The notice may be made by telephone, facsimile transmittal, or electronic mail.

3.4.3 Other Clean Air Act Requirements

The 1990 CAA Amendments established a program to reduce potential precursors of acidic deposition. The Acid Rain Program was delineated in Title IV of the CAA Amendments and required EPA to develop the program. EPA's final regulations were promulgated on January 11, 1993, and included permit provisions (40 CFR Part 72), allowance system (Part 73), continuous emission monitoring (Part 75), excess emission procedures (Part 77), and appeal procedures (Part 78).

EPA's Acid Rain Program applies to all existing and new utility units except those serving a generator less than 25 MW, existing simple cycle CTs, and certain non-utility facilities; units that fall under the program are referred to as affected units. The EPA regulations are applicable to the Project for the purposes for obtaining a permit and allowances, as well as emission monitoring. New units are required to obtain permits under the program by submitting a complete application 24 months before the date on which the unit commences operation (e.g., first fire). (Rule 62-210.370). The City has submitted the Acid Rain Program application for this project.

The permit would require the units to hold SO_2 emission allowances. An allowance is a market-based financial instrument that is equivalent to 1 ton of SO_2 emissions. Allowances can be sold, purchased, or traded.

CEM for SO_2 and NO_x is required for gas-fired and oil-fired affected units. When an SO_2 CEM is selected to monitor SO_2 mass emissions, a flow monitor is also required. Alternately, SO_2 emissions may be determined using procedures established in Appendix D, 40 CFR Part 75 (flow proportional oil sampling or manual daily oil sampling). CO_2 emissions must also be determined either through a CEM (e.g., as a diluent for NO_x monitoring) or calculation. Alternate procedures, test methods, and quality assurance/quality control (QA/QC) procedures for CEM are specified (Part 75, Appendices A through I). The acid rain CEM requirements including QA/QC procedures are, in general, more stringent than those specified in the NSPS for Subpart GG. New units are required to meet the requirements by the later of January 1, 1995, or not later than 90 days after the unit commences commercial operation. The City will install a NOx CEMS and utilize the alternative procedures for SO_2 and CO_2 in accordance with the applicable Title IV appendixes.

TABLE 3-1
NATIONAL AND STATE AAQS, ALLOWABLE PSD INCREMENTS, AND SIGNIFICANT IMPACT LEVELS

		AAQS ($\mu g/m^3$)[a]			PSD Increments ($\mu g/m^3$)[a]		
Pollutant	**Averaging Time**	**Primary Standard**	**Secondary Standard**	**Florida**	**Class I**	**Class II**	**PSD Class II Significant Impact Levels ($\mu g/m^3$)** [b]
Particulate Matter[c] (PM_{10})	Annual Arithmetic Mean	50	50	50	4	17	1
	24-Hour Maximum	150	150	150	8	30	5
Sulfur Dioxide	Annual Arithmetic Mean	80	NA	60	2	20	1
	24-Hour Maximum	365	NA	260	5	91	5
	3-Hour Maximum	NA	1,300	1,300	25	512	25
Carbon Monoxide	8-Hour Maximum	10,000	10,000	10,000	NA	NA	500
	1-Hour Maximum	40,000	40,000	40,000	NA	NA	2,000
Nitrogen Dioxide	Annual Arithmetic Mean	100	100	100	2.5	25	1
Ozone[c]	1-Hour Maximum	235	235	235	NA	NA	NA
Lead	Calendar Quarter Arithmetic Mean	1.5	1.5	1.5	NA	NA	NA

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

[a] Short-term maximum concentrations are not to be exceeded more than once per year except for the PM_{10} and ozone AAQS. The 24-hour PM_{10} AAQS is attained when the expected number of days per year with a 24-hour concentration above 150 μ/m^3 is equal to or less than 1. For modeling purposes, compliance is based on the sixth highest 24-hour concentration over a 5-year period. For ozone, the daily maximum 1-hour concentration cannot be exceeded an average of more than one per year.

[b] Maximum concentrations are not to be exceeded.

[c] On July 18, 1997, EPA promulgated revised AAQS for particulate matter and ozone. For particulate matter, $PM_{2.5}$ standards were introduced with a 24-hour standard of 65 g/m^3 (3-year average of 98th percentile) and an annual standard of 15 g/m^3 (3-year average at community monitors).
The ozone standard was modified to be 0.08 ppm; achieved when 3-year average of 99th percentile is 0.08 ppm 157 μ/m^3 or less. FDEP has not yet adopted these standards.

Sources: Federal Register, Vol. 43, No. 118, June 19, 1978.
40 CFR 50; 40 CFR 52.21.
Chapter 62-204, F.A.C.

TABLE 3-2
PSD SIGNIFICANT EMISSION RATES

Pollutant	Regulated Under	Significant Emission Rate (TPY)
Sulfur Dioxide	NAAQS, NSPS	40
Particulate Matter [PM(TSP)]	NSPS	25
Particulate Matter (PM_{10})	NAAQS	15
Nitrogen Dioxide	NAAQS, NSPS	40
Carbon Monoxide	NAAQS, NSPS	100
Volatile Organic Compounds (Ozone)	NAAQS, NSPS	40
Lead	NAAQS	0.6
Sulfuric Acid Mist	NSPS	7
Total Fluorides	NSPS	3
Total Reduced Sulfur	NSPS	10
Reduced Sulfur Compounds	NSPS	10
Hydrogen Sulfide	NSPS	10
Mercury	NESHAP	0.1

NAAQS = National Ambient Air Quality Standards.
NSPS = New Source Performance Standards.
NESHAP = National Emission Standards for Hazardous Air Pollutants.

Sources: 40 CFR 52.21; Rule 62-212.400.

TABLE 3-3
SUMMARY OF MAXIMUM POTENTIAL ANNUAL EMISSIONS FOR THE PROPOSED HOPKINS UNIT 2 REPOWERING PROJECT
COMPARED TO THE PSD SIGNIFCANT EMISSION RATES

Pollutant	Annual Emissions (TPY)							PSD Significant Emission Rate (tons/year)	PSD Review Required?
	Maximum Potential Annual Emissions (TPY) for CT and DB Operating Scenarios [a]					Actual Emissions from Existing Unit 2 [b]	Emission Changes-Proposed Project with Existing Unit 2 Shutdown		
	A	B	C	D	E				
SO_2	43.4	50.5	211.7	211.7	43.4	1642.0	-1,430	40	No
PM	48.2	65.2	111.8	111.8	39.4	136.3	-25	25	No
PM_{10}	48.2	65.2	111.8	111.8	39.4	97.5	14	15	No
NO_x	142.0	164.9	243.7	265.7	255.6	843.3	-578	40	No
CO	171.1	264.6	340.1	340.1	171.1	241.1	99	100	No
VOC (as methane)	31.2	46.8	47.4	47.4	31.2	19.7	28	40	No
Sulfuric Acid Mist	4.3	5.8	39.7	39.7	4.3	73.0	-33	7	No
Lead	0.000	0.000	0.05	0.05	0.00	0.019	0	0.6	No
Mercury	0.0000	0.0000	0.00	0.00	0.00	0.0014	0	0.1	No

[a] Based on the following hours of operation for each operating scenario:

	A	B	C	D	E
Combined Cycle Operation					
CT, natural gas-firing	8,760	5,110	1,610	5,110	0
CT and duct burner, natural gas-firing	0	3,650	3,650	150	0
CT, fuel oil-firing	0	0	3,500	0	0
CT, fuel oil-firing; duct burner, natural gas-firing	0	0	0	3,500	0
CT, fuel oil-firing; duct burner, natural gas-firing					
Simple Cycle Operation	0	0	0	0	8,760

[b] Based on maximum annual average PM, PM10, CO, VOC, lead, and mercury emissions based on AOR data for the 24-month consecutive period from 2001 to 2005. For SO_2 and NO_x, based on the maximum annual average emissions from monthly CEM data from March 2001 to February 2006.

TABLE 3-4
SUMMARY OF MAXIMUM SHORT-TERM EMISSIONS
FOR THE PROPOSED HOPKINS UNIT 2 REPOWERING PROJECT

Pollutant		CT Natural Gas-Firing Emission Rate	CT Natural Gas-Firing Basis	CT Distillate Oil-Firing Emission Rate	CT Distillate Oil-Firing Basis
Combined Cycle Operation					
		No Duct Firing		*No Duct Firing*	
SO_2		9.9 lb/hr	2 gr S/100 scf	102.0 lb/hr	0.05% S
PM/PM_{10}	CT	9.0 lb/hr	filterable	37.6 lb/hr	filterable
PM/PM_{10}	CT/SCR	11.0 lb/hr	filterable	37.6 lb/hr	filterable
NO_x	CT/SCR	32.4 lb/hr	5 ppmvd@15%O2	77.5 lb/hr	10 ppmvd@15%O2
CO		39.1 lb/hr	9.9 ppmvd@15%O2	82.2 lb/hr	17.4 ppmvd@15%O2
VOC		7.1 lb/hr	3.16 ppmvd@15%O2	7.5 lb/hr	2.77 ppmvd@15%O2
		Duct Firing with Gas [a]		*Duct Firing with Gas* [a]	
SO_2		13.8 lb/hr	2 gr S/100 scf	105.9 lb/hr	2 gr S/100 scf (DB)
PM/PM_{10}	CT/SCR	20.3 lb/hr	filterable	47.0 lb/hr	filterable
NO_x	CT/SCR	45.0 lb/hr	5 ppmvd@15%O2	102.6 lb/hr	10 ppmvd@15%O2
CO		90.3 lb/hr	16.7 ppmvd@15%O2	133.4 lb/hr	21.2 ppmvd@15%O2
VOC		15.7 lb/hr	5.7 ppmvd@15%O2	16.0 lb/hr	5.2 ppmvd@15%O2
Simple Cycle Operation					
SO_2		9.9 lb/hr	2 gr S/100 scf	NA	
PM/PM_{10}		9.0 lb/hr	filterable	NA	
NO_x		58.4 lb/hr	9 ppmvd@15%O2	NA	
CO		39.1 lb/hr	9.9 ppmvd@15%O2	NA	
VOC		7.1 lb/hr	3.2 ppmvd@15%O2	NA	

Note: Based on 59 °F ambient inlet air temperature.
NA= not applicable

[a] Basis of duct burner emissions :

Pollutant	Natural Gas-Firing	Oil-Firing
PM_{10}	0.0120 lb/MMBtu	0.0150 lb/MMBtu
NO_x	0.10 lb/MMBtu	0.15 lb/MMBtu
CO	0.072 lb/MMBtu	0.10 lb/MMBtu
VOC	0.012 lb/MMBtu	0.012 lb/MMBtu

APPENDIX A

EXPECTED PERFORMANCE AND EMISSIONS INFORMATION FOR THE COMBUSTION TURBINE AND DUCT BURNER

TABLE A-SUM-1
SUMMARY OF MAXIMUM SHORT-TERM EMISSIONS FOR THE HOPKINS 2 REPOWERING PROJECT

		Maximum Hourly Emissions (lb/hr) [a, b]				
		Combined Cycle (CC)				Simple Cycle (SC)
	CT Fuel:	NG	NG	FO	FO	NG
Pollutant	Load:	100%	100% w/DB on NG	100%	100% w/DB on NG	100%
Combustion Turbine						
SO_2		9.90	13.8	102.0	105.9	9.90
PM		11.0	20.3	37.6	47.0	9.00
PM_{10}		11.0	20.3	37.6	47.0	9.00
NO_x		32.4	45.0	77.5	102.6	58.4
CO		39.1	90.3	82.2	133.4	39.1
VOC (as methane)		7.12	15.7	7.5	16.0	7.12
Sulfuric Acid Mist		0.99	1.77	20.4	21.2	0.99
Lead		0.00	0.00	0.028	0.028	0.00
Mercury		0.00	0.00	0.0024	0.0024	0.00
HAPs		0.78	1.09	2.45	2.45	0.78
Combustion Turbines:	2					
SO_2		19.8	27.6	204.0	211.9	19.8
PM		22.0	40.7	75.2	93.9	18.0
PM_{10}		22.0	40.7	75.2	93.9	18.0
NO_x		64.8	89.9	154.9	205.1	117
CO		78.1	181	164	266.9	78.1
VOC (as methane)		14.24	31.3	14.9	32.0	14.24
Sulfuric Acid Mist		1.98	3.55	40.80	42.4	1.98
Lead		0.00	0.00	0.055	0.055	0.00
Mercury		0.00	0.00	0.0047	0.0047	0.00
HAPs		1.56	2.17	4.91	4.9	1.56

[a] Based on 59 °F ambient inlet air temperature.
Source: GE, 2005 - CT Performance Data;
Golder, 2005

TABLE A-SUM-2
SUMMARY OF MAXIMUM ANNUAL EMISSIONS FOR THE HOPKINS 2 REPOWERING PROJECT

Operating Scenario	HP2 Repowering- Maximum Emissions (TPY) based on hours for					Actual [c] Emissions- 2-yr Average (TPY)	Net Emissions (Maximum Future Potential - Actual) based on hours for					PSD Significant Emission Rate (TPY)
	A	B	C	D	E		A	B	C	D	E	
CC/ CT-NG	8,760	5,110	1,610	5,110	0		8,760	5,110	1,610	5,110	0	
CC/ CT & DB- NG	0	3,650	3,650	150	0		0	3,650	3,650	150	0	
CC/ CT -FO	0	0	3,500	0	0		0	0	3,500	0	0	
	0	0	0	0	0		0	0	0	0	0	
CC/ CT -FO; DB -NG	0	0	0	3,500	0		0	0	0	3,500	0	
SC/ NG	0	0	0	0	8,760		0	0	0	0	8,760	
TOTAL	8,760	8,760	8,760	8,760	8,760		8,760	8,760	8,760	8,760	8,760	
Combustion Turbine												
SO_2	43.4	50.5	211.7	211.7	43.4	1,642.0	-1,599	-1,591	-1,430	-1,430	-1,599	40
PM	48.2	65.2	111.8	111.8	39.4	136.3	-88	-71	-25	-25	-97	25
PM_{10}	48.2	65.2	111.8	111.8	39.4	97.5	-49	-32	14	14	-58	15
NO_x	142.0	164.9	243.7	265.7	255.6	843.3	-701	-678	-600	-578	-588	40
CO	171.1	264.6	340.1	340.1	171.1	241.1	-70	23	99	99	-70	100
VOC (as methane)	31.2	46.8	47.4	47.4	31.2	19.7	11	27	28	28	11	40
Sulfuric Acid Mist	4.3	5.8	39.7	39.7	4.3	73.0	-68.7	-67.3	-33.3	-33.3	-68.7	7
Lead	0.00	0.00	0.05	0.05	0.00	0.02	-0.019	-0.019	0.030	0.030	-0.019	0.6
Mercury	0.000	0.000	0.004	0.004	0.000	0.0014	-0.001	-0.001	0.003	0.003	-0.001	0.1
HAPs	3.4	4.0	6.9	6.4	3.4							
Combustion Turbines: 2												
SO_2	87	101	423	423	87	1,642.0	-1,555	-1,541	-1,219	-1,219	-1,555	40
PM	96	130	223.6	224	79	136.3	-40	-6	87	87	-57	25
PM_{10}	96	130	223.6	224	79	97.5	-1	33	126	126	-19	15
NO_x	284	330	487	531	511	843.3	-559	-514	-356	-312	-332	40
CO	342	529	680	680	342	241.1	101	288	439	439	101	100
VOC (as methane)	62.4	93.5	94.7	94.7	62.4	19.7	43	74	75	75	43	40
Sulfuric Acid Mist	8.7	11.5	79.5	79.5	8.7	73.0	-64.4	-61.5	6.5	6.5	-64.4	7
Lead	0.000	0.000	0.097	0.097	0.000	0.02	-0.019	-0.019	0.08	0.08	-0.02	0.6
Mercury	0.000	0.000	0.008	0.008	0.000	0.0014	-0.001	-0.001	0.007	0.007	-0.001	0.1
HAPs	6.83	7.95	13.81	12.7	6.8							

[b] Basis of Emissions for Hopkins 2 Repowering:

	Natural gas		Fuel oil			
SO2	2 gr S/100 scf		0.050%	S		
PM	filterable			filterable		(includes ammonium sulfate from SCR for CC operation)
PM10	filterable			filterable		(includes ammonium sulfate from SCR for CC operation)
NOx	5 ppmvd	(5	10	ppmvd	(10	w/DB) CC operation (corrected to 15% oxygen)
NOx	9 ppmvd		NA			SC operation (corrected to 15% oxygen)
CO	12 ppmvd	(29	25	ppmvd	(50	w/DB)
VOC	3.5 ppmvw	(8.7	3.5	ppmvw	(7.9	w/DB) (assumes 50% UHC)

[c] Actual emissions based on CEMS for SO_2 and NO_x; AP-42 factors for other pollutants.
CEMS data used from March 2001 to February 2006. AOR data used 2001 to 2005.
Emission factors based on latest factors from AP-42 and used for all years (AOR emissions adjusted accordingly). PM/PM10 factors based on filterable PM.

TABLE A-1
DESIGN INFORMATION AND STACK PARAMETERS FOR THE HOPKINS UNIT 2 REPOWERING PROJECT
GE FRAME 7FA, DRY LOW NO_X COMBUSTOR, NATURAL GAS, BASE LOAD, WITH NATURAL GAS DUCT FIRING

Parameter		CT Only Turbine Inlet Temperature 25 °F	 59 °F	 95 °F		CT with Duct Burner (Natural Gas) Turbine Inlet Temperature 25 °F w/DB	 59 °F w/DB	 95 °F w/DB
Combustion Turbine Performance								
Power output (MW)	p	187.8	174.40	160.3		187.8	174.4	160.3
Heat rate (Btu/kWh, LHV)	p	9,110	9,270	9,495		9,110	9,270	9,495
(Btu/kWh, HHV)		10,112	10,290	10,539		10,112	10,290	10,539
Heat Input (MMBtu/hr, LHV)	p	1,710.9	1,616.7	1,522		1,711	1,616.7	1,522
(MMBtu/hr, HHV)		1,899	1,795	1,689		1,899	1,795	1,689
Evaporative Cooler	p	Off	On	On		Off	On	On
Relative Humidity (%)	p	87	78	50		87	78	50
Natural gas								
Fuel heating value (Btu/lb, LHV)	p	20,714	20,714	20,714		20,714	20,714	20,714
(Btu/lb, HHV)		22,993	22,993	22,993		22,993	22,993	22,993
(HHV/LHV)		1.110	1.110	1.110		1.110	1.110	1.110
Duct Burner (DB)								
Heat input (MMBtu/hr, HHV)		0	0	0		765	712	663
(MMBtu/hr, LHV)		0	0	0		688.8	641.1	596.9
CT/DB Exhaust Flow								
Mass Flow (lb/hr)- with no margin		3,826,000	3,607,000	3,382,000	c	3,856,721.2	3,635,594	3,408,622
- provided	p	3,826,000	3,607,000	3,382,000				
Temperature (°F)	p	1,081	1,114	1,144		1,081	1,114	1,144
Moisture (% Vol.)	p	7.54	8.55	10.28	c	10.26	11.21	12.88
Oxygen (% Vol.)	p	12.77	12.57	12.22	c	9.76	9.61	9.30
Molecular Weight	c	28.49	28.38	28.19	c	28.31	28.20	28.02
	p	28.49	28.37	28.18				
Fuel Usage								
Natural Gas								
Fuel usage CT (lb/hr) = Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu (Fuel Heat Content, Btu/lb (LHV))								
Heat input (MMBtu/hr, LHV)		1,711	1,617	1,522		1,711	1,617	1,522
Heat content (Btu/lb, LHV)		20,714	20,714	20,714		20,714	20,714	20,714
Fuel usage (lb/hr)- calculated	c	82,596	78,049	73,477		82,596	78,049	73,477
		1,036						
Heat content (Btu/cf, LHV)- assumed		933	933	933		933	933	933
Fuel density (lb/ft^3)		0.0451	0.0451	0.0451		0.0451	0.0451	0.0451
Fuel usage (cf/hr)- calculated		1,832,961	1,732,040	1,630,584		1,832,961	1,732,040	1,630,584
Fuel Usage - Duct Burner Only								
Fuel usage (lb/hr)- calculated		0	0	0	c	33,253	30,950	28,816
Fuel usage (cf/hr)- calculated		0	0	0		737,941	686,838	639,485
Bypass Stack and Flow Conditions								
Stack Height (ft)		150	150	150		150	150	150
Diameter (ft)		18	18	18		18	18	18
Velocity (ft/sec) = Volume flow (acfm) / [((diameter)² /4) x 3.14159] / 60 sec/min								
Mass flow (lb/hr)		3,826,000	3,607,000	3,382,000		NA	NA	NA
Stack Temperature (°F)		1,081	1,114	1,144		NA	NA	NA
Molecular weight		28.49	28.38	28.19		NA	NA	NA
Volume flow (acfm)		2,517,808	2,433,691	2,341,021		NA	NA	NA
Diameter (ft)		18	18	18		NA	NA	NA
Velocity (ft/sec)- calculated		164.9	159.4	153.3		NA	NA	NA
HRSG Stack and Flow Conditions								
Stack Height (ft)		150	150	150		150	150	150
Diameter (ft)		18	18	18		18	18	18
Mass flow (lb/hr)		3,826,000	3,607,000	3,382,000		3,856,721	3,635,594	3,408,622
Stack Temperature (°F)		203.0	202.0	201.0		189.0	188.0	190
Molecular weight		28.49	28.38	28.19		28.31	28.20	28.02
Volume flow (acfm)		1,083,262	1,023,573	964,723		1,075,526	1,016,095	961,902
Diameter (ft)		18	18	18		18	18	18
Velocity (ft/sec)- calculated		70.9	67.0	63.2		70.4	66.5	63.0

Note: Universal gas constant = 1,545 ft-lb(force)/°R; atmospheric pressure = 2,116.8 lb(force)/ft²; 14.7 lb/ft^3.

Source: GE, 2006 - CT Performance Data; Golder, 2006 - DB Calculations.

TABLE A-2
MAXIMUM EMISSIONS FOR CRITERIA POLLUTANTS FOR THE HOPKINS UNIT 2 REPOWERING PROJECT
GE FRAME 7FA, DRY LOW NOX COMBUSTOR, NATURAL GAS, BASE LOAD, WITH NATURAL GAS DUCT FIRING

Parameter	CT Only *Turbine Inlet Temperature* 25 °F	59 °F	95 °F	CT with Duct Burner *Turbine Inlet Temperature* 25 °F w/DB	59 °F w/DB	95 °F w/DB
Particulate from CT, DB, and SCR						
Total PM_{10} = PM_{10} (front half) + PM_{10} ($(NH_4)_2SO_4$) from SCR only						
a. PM_{10} (front half) (lb/hr)						
CT- provided	9.0	9.0	9.0	9.0	9.0	9.0
DB (lb/hr) - calculated	0.0	0.0	0.0	9.2	8.5	8.0
Total CT/DB emission rate (lb/hr)	9.0	9.0	9.0	18.2	17.5	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	10.5	9.9	9.3	14.7	13.8	13.0
Conversion (%) from SO_2 to SO_3	9.8	9.8	9.8	9.8	9.8	9.8
MW SO_3/ SO_2 (80/64)	1.3	1.3	1.3	1.3	1.3	1.3
Conversion (%) from SO_3 to $(NH_4)_2(SO_4)$	100	100	100	100	100	100
MW $(NH_4)_2$ SO_4/ SO_3 (132/80)	1.7	1.7	1.7	1.7	1.7	1.7
SCR Particulate (lb/hr)- calculated	2.12	2.00	1.88	2.97	2.79	2.62
CT emission rate (lb/hr) [a + b] assumes SCR	11.1	11.0	10.9	11.1	11.0	10.9
HRSG stack emission rate (lb/hr) [a + b]	11.1	11.0	10.9	21.1	20.3	19.6
(lb/mmBtu, HHV)	0.0059	0.0061	0.0064	0.0079	0.0081	0.0083
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)	1,832,961	1,732,040	1,630,584	2,570,901	2,418,878	2,270,068
Sulfur content (grains/ 100 cf)	2	2	2	2	2	2
lb SO_2 /lb S (64/32)	2	2	2	2	2	2
CT emission rate (lb/hr)	10.5	9.9	9.3	10.5	9.9	9.3
HRSG stack emission rate (lb/hr)	10.5	9.9	9.3	14.7	13.8	13.0
(lb/MW)	0.056	0.057	0.058			
Nitrogen Oxides						
NOx (lb/hr) = NOx (ppmvd@ 15% O_2) x {[20.9 x (1-Moisture (%)/100] - Oxygen, dry(%)} x 2116.8 lb/ft^2 x Volume flow (acfm) x 46 (mole. wgt NOx) x 60 min/hr / [1545 x (CT temp.(°F) + 460) x (20.9-15) x 1,000,000 (adj. for ppm)]						
CT/DB, ppmvd @15% O_2	9	9	9	14.5	14.4	14.4
Moisture (%)	7.54	8.55	10.28	10.26	11.21	12.88
Oxygen (%)	12.77	12.57	12.22	9.76	9.61	9.30
Turbine Flow (acfm)	2,517,808	2,433,691	2,341,021	2,553,753	2,468,107	2,373,678
Turbine Exhaust Temperature (°F)	1,081	1,114	1,144	1,081	1,114	1,144
CT emission rate (lb/hr)	61.8	58.4	55.0	61.8	58.4	55.0
(lb/MW)	0.3	0.3	0.3	NA	NA	NA
HRSG emission rate (lb/hr)	61.8	58.4	55.0	138.2	129.5	121.2
HRSG stack emission rate, ppmvd @ 15% O_2	5.0	5.0	5.0	5.0	5.0	5.0
HRSG Stack emission rate (lb/hr)	34.3	32.4	30.5	47.8	45.0	42.2
(lb/MW)	0.18	0.19	0.19			
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	12	12	12	28.6	28.5	28.6
Basis, ppmvd @ 15% O2 - calculated	9.99	9.90	9.73	16.8	16.7	16.5
Moisture (%)	7.54	8.55	10.28	10.26	11.21	12.88
Oxygen (%)	12.77	12.57	12.22	9.76	9.61	9.30
Turbine Flow (acfm)	2,517,808	2,433,691	2,341,021	2,553,753	2,468,107	2,373,678
Turbine Exhaust Temperature (°F)	1,081	1,114	1,144	1,081	1,114	1,144
CT emission rate (lb/hr)	41.7	39.1	36.2	41.7	39.1	36.2
HRSG stack emission rate (lb/hr)	41.7	39.1	36.2	96.8	90.3	83.9

TABLE A-2
MAXIMUM EMISSIONS FOR CRITERIA POLLUTANTS FOR THE HOPKINS UNIT 2 REPOWERING PROJECT
GE FRAME 7FA, DRY LOW NOX COMBUSTOR, NATURAL GAS, BASE LOAD, WITH NATURAL GAS DUCT FIRING

Parameter	CT Only Turbine Inlet Temperature			CT with Duct Burner Turbine Inlet Temperature		
	25 °F	59 °F	95 °F	25 °F w/DB	59 °F w/DB	95 °F w/DB
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	3.50	3.50	3.50	8.6	8.7	8.8
Basis, ppmvd @ 15% O2 - calculated	3.15	3.16	3.16	5.67	5.71	5.80
Moisture (%)	7.54	8.55	10.28	10.26	11.21	12.88
Oxygen (%) wet	12.77	12.57	12.22	9.76	9.61	9.30
Oxygen (%) dry						
Turbine Flow (acfm)	2,517,808	2,433,691	2,341,021	2,553,753	2,468,107	2,373,678
Turbine Exhaust Temperature (°F)	1,081	1,114	1,144	1,081	1,114	1,144
CT emission rate (lb/hr)	7.52	7.12	6.72	7.52	7.12	6.72
HRSG stack Emission rate (lb/hr)	7.52	7.12	6.72	16.70	15.66	14.67
Sulfuric Acid Mist						
Sulfuric Acid Mist (lb/hr)= SO_2 emission (lb/hr) x Conversion to H_2SO_4 (% by weight)/100						
CT SO_2 emission rate (lb/hr) - provided	10.5	9.9	9.3	10.5	9.9	9.3
CT Conversion to H_2SO_4 (% by weight) - provided	10	10	10	10	10	10
DB SO_2 emission rate (lb/hr) - provided	0	0	0	4	4	4
DB Conversion to H_2SO_4 (%) - provided	20	20	20	20	20	20
CT emission rate (lb/hr)	1.05	0.99	0.93	1.05	0.99	0.93
HRSG stack Emission rate (lb/hr)	1.05	0.99	0.93	1.89	1.77	1.66
Lead						
Lead (lb/hr) = NA						
Emission Rate Basis	NA	NA	NA	NA	NA	NA
CT emission rate (lb/hr)	NA	NA	NA	NA	NA	NA
HRSG stack Emission rate (lb/hr)	NA	NA	NA	NA	NA	NA

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

Source: GE, 2006 - CT Performance Data; Golder, 2006 - DB Calculations.

TABLE A-3
DESIGN INFORMATION AND STACK PARAMETERS FOR THE HOPKINS UNIT 2 REPOWERING PROJECT
GE FRAME 7FA, DRY LOW NO_X COMBUSTOR, NATURAL GAS, 75% LOAD

Parameter	Turbine Inlet Temperature		
	25 °F	59 °F	95 °F
Combustion Turbine Performance			
Power output (MW)	140.9	130.8	120.3
Heat rate (Btu/kWh, LHV)	9,840	10,080	10,410
(Btu/kWh, HHV)	10,923	11,189	11,555
Heat Input (MMBtu/hr, LHV)	1,387	1,319	1,252
(MMBtu/hr, HHV)	1,539	1,464	1,390
Relative Humidity (%)	87	78	50
Fuel heating value (Btu/lb, LHV)	20,714	20,714	20,714
(Btu/lb, HHV)	22,993	22,993	22,993
(HHV/LHV)	1.110	1.110	1.110
CT Exhaust Flow			
Mass Flow (lb/hr)- with no margin	3,019,000	2,905,000	2,798,000
- provided	3,019,000	2,905,000	2,798,000
Temperature (°F)	1,136	1,161	1,186
Moisture (% Vol.)	7.66	8.45	9.74
Oxygen (% Vol.)	12.64	12.57	12.43
Molecular Weight	28.48	28.39	28.24
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)	1,387	1,319	1,252
Heat content (Btu/lb, LHV)	20,714	20,714	20,714
Fuel usage (lb/hr)- calculated	66,935	63,653	60,457
Heat content (Btu/cf, LHV)- assumed	933	933	933
Fuel density (lb/ft^3)	0.0450	0.0450	0.0450
Fuel usage (cf/hr)- calculated	1,485,951	1,413,074	1,342,125
Bypass Stack and Flow Conditions			
Stack Height (ft)	150	150	150
Diameter (ft)	18	18	18
Velocity (ft/sec) = Volume flow (acfm) / [((diameter)² /4) x 3.14159] / 60 sec/min			
Mass flow (lb/hr)	3,019,000	2,905,000	2,798,000
Stack Temperature (°F)	1,136	1,161	1,186
Molecular weight	28.48	28.39	28.24
Volume flow (acfm)	2,058,166	2,017,660	1,983,749
Diameter (ft)	18	18	18
Velocity (ft/sec)- calculated	134.8	132.1	129.9
HRSG Stack and Flow Conditions			
Stack Height (ft)	150	150	150
Diameter (ft)	18	18	18
Mass flow (lb/hr)	3,019,000	2,905,000	2,798,000
Stack Temperature (°F)	187	188	190
Molecular weight	28.48	28.39	28.24
Volume flow (acfm)	834,099	806,317	783,135
Diameter (ft)	18	18	18
Velocity (ft/sec)- calculated	54.6	52.8	51.3

Note: Universal gas constant = 1,545 ft-lb(force)/°R; atmospheric pressure = 2,116.8 lb(force)/ft²; 14.7 lb/ft^3

Source: GE, 2006 - CT Performance Data; Golder, 2006.

TABLE A-4
MAXIMUM EMISSIONS FOR CRITERIA POLLUTANTS FOR THE HOPKINS UNIT 2 REPOWERING PROJECT
GE FRAME 7FA, DRY LOW NO_X COMBUSTOR, NATURAL GAS, 75% LOAD

Parameter	Turbine Inlet Temperature 25 °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) (lb/hr)			
CT- 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	8.5	8.1	7.7
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	1.72	1.63	1.55
CT emission rate (lb/hr) [a]	9.0	9.0	9.0
HRSG stack emission rate (lb/hr) [a + b]	10.7	10.6	10.6
(lb/mmBtu, HHV)	0.0070	0.0073	0.0076
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)	1,485,951	1,413,074	1,342,125
Sulfur content (grains/ 100 cf)	2	2	2
lb SO_2 /lb S (64/32)	2	2	2
CT emission rate (lb/hr)	8.5	8.1	7.7
HRSG Stack emission rate (lb/hr)	8.5	8.1	7.7
Nitrogen Oxides			
NOx (lb/hr) = NOx (ppmvd@ 15% O_2) x {[20.9 x (1-Moisture (%)/100] - Oxygen, dry(%)} x 2116.8 lb/ft^2 x Volume flow (acfm) x 46 (mole. wgt NOx) x 60 min/hr / [1545 x (CT temp.(°F) + 460) x (20.9-15) x 1,000,000 (adj. for ppm)]			
CT / DB, ppmvd @15% O_2	9	9	9.0
Moisture (%)	7.66	8.45	9.74
Oxygen (%)	12.64	12.57	12.43
Turbine Flow (acfm)	2,058,166	2,017,660	1,983,749
Turbine Exhaust Temperature (°F)	1,136	1,161	1,186
CT Emission rate (lb/hr)	49.5	47.1	44.7
HRSG Stack emission rate, ppmvd @ 15% O_2	5	5	5.0
HRSG Stack emission rate (lb/hr)	27.5	26.2	24.9
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	12	12	12
Moisture (%)	7.66	8.45	9.74
Turbine Flow (acfm)	2,058,166	2,017,660	1,983,749
Turbine Exhaust Temperature (°F)	1,136	1,161	1,186
HRSG Exhaust Temperature (°F)	187	188	190
CT Emission rate (lb/hr)	32.9	31.5	30.0
HRSG Stack emission rate (lb/hr)	32.9	31.5	30.0

TABLE A-4
MAXIMUM EMISSIONS FOR CRITERIA POLLUTANTS FOR THE HOPKINS UNIT 2 REPOWERING PROJECT
GE FRAME 7FA, DRY LOW NO_X COMBUSTOR, NATURAL GAS, 75% LOAD

Parameter	Turbine Inlet Temperature 25 °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	3.50	3.5	3.50
Moisture (%)	7.66	8.45	9.74
Turbine Flow (acfm)	2,058,166	2,017,660	1,983,749
Turbine Exhaust Temperature (°F)	1,136	1,161	1,186
HRSG Exhaust Temperature (°F)	186.8	186.8	186.8
CT Emission rate (lb/hr)	5.94	5.73	5.55
HRSG Stack emission rate (lb/hr)	5.94	5.73	5.55
Sulfuric Acid Mist			
Sulfuric Acid Mist (lb/hr)= SO_2 emission (lb/hr) x Conversion to H_2SO_4 (% by weight)/100			
CT SO_2 emission rate (lb/hr) - provided	8.5	8.1	7.7
CT Conversion to H_2SO_4 (% by weight) - provided	10	10	10
DB SO_2 emission rate (lb/hr) - provided	0	0	0
DB Conversion to H_2SO_4 (%) - provided	20	20	20
CT Emission rate (lb/hr)	0.85	0.81	0.77
HRSG Stack emission rate (lb/hr)	0.85	0.81	0.77
Lead			
Lead (lb/hr) = NA			
Emission Rate Basis	NA	NA	NA
CT Emission rate (lb/hr)	NA	NA	NA
HRSG Stack emission rate (lb/hr)	NA	NA	NA

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

Source: GE, 2006 - CT Performance Data; Golder, 2006.

TABLE A-5
DESIGN INFORMATION AND STACK PARAMETERS FOR THE HOPKINS UNIT 2 REPOWERING PROJECT
GE FRAME 7FA, DRY LOW NO_X COMBUSTOR, NATURAL GAS, 60% LOAD

Parameter	Turbine Inlet Temperature 25 °F	59 °F	95 °F
Combustion Turbine Performance			
Power output (MW)	112.7	104.6	96.2
Heat rate (Btu/kWh, LHV)	10,880	11,160	11,460
(Btu/kWh, HHV)	12,077	12,387	12,721
Heat Input (MMBtu/hr, LHV)	1,226	1,167	1,103
(MMBtu/hr, HHV)	1,361	1,296	1,224
Relative Humidity (%)	87	78	50
Fuel heating value (Btu/lb, LHV)	20,714	20,714	20,714
(Btu/lb, HHV)	22,993	22,993	22,993
(HHV/LHV)	1.110	1.110	1.110
CT Exhaust Flow			
Mass Flow (lb/hr)- with no margin	2,707,000	2,608,000	2,523,000
- provided	2,707,000	2,608,000	2,523,000
Temperature (°F)	1,167	1,190	1,200
Moisture (% Vol.)	7.52	8.32	9.54
Oxygen (% Vol.)	12.80	12.73	12.66
Molecular Weight	28.49	28.40	28.25
Fuel Usage			
Fuel usage (lb/hr) = Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu (Fuel Heat Content, Btu/lb (LHV))			
Heat input (MMBtu/hr, LHV)	1,226	1,167	1,103
Heat content (Btu/lb, LHV)	20,714	20,714	20,714
Fuel usage (lb/hr)- calculated	59,197	56,353	53,225
Heat content (Btu/cf, LHV)- assumed	933	933	933
Fuel density (lb/ft^3)	0.0450	0.0450	0.0450
Fuel usage (cf/hr)- calculated	1,314,153	1,251,028	1,181,580
Bypass Stack and Flow Conditions			
Stack Height (ft)	150	150	150
Diameter (ft)	18	18	18
Velocity (ft/sec) = Volume flow (acfm) / [((diameter)^2 /4) x 3.14159] / 60 sec/min			
Mass flow (lb/hr)	2,707,000	2,608,000	2,523,000
Stack Temperature (°F)	1,167	1,190	1,200
Molecular weight	28.49	28.40	28.25
Volume flow (acfm)	1,880,545	1,843,332	1,803,432
Diameter (ft)	18	18	18
Velocity (ft/sec)- calculated	123.2	120.7	118.1
HRSG Stack and Flow Conditions			
Stack Height (ft)	150	150	150
Diameter (ft)	18	18	18
Mass flow (lb/hr)	2,707,000	2,608,000	2,523,000
Stack Temperature (°F)	175	178	182
Molecular weight	28.49	28.40	28.25
Volume flow (acfm)	734,303	712,196	697,689
Diameter (ft)	18	18	18
Velocity (ft/sec)- calculated	48.1	46.6	45.7

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, 2006 - CT Performance Data; Golder, 2006.

TABLE A-6
MAXIMUM EMISSIONS FOR CRITERIA POLLUTANTS FOR THE HOPKINS UNIT 2 REPOWERING PROJECT
GE FRAME 7FA, DRY LOW NO_X COMBUSTOR, NATURAL GAS, 60% LOAD

Parameter	Turbine Inlet Temperature 25 °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) (lb/hr)			
CT- 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	7.5	7.1	6.8
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 $(NH_4)_2SO_4$/ SO_3 (132/80)	1.7	1.7	1.7
SCR Particulate (lb/hr)- calculated	1.52	1.44	1.36
CT emission rate (lb/hr) [a]	9.0	9.0	9.0
HRSG stack emission rate (lb/hr) [a + b]	10.5	10.4	10.4
(lb/mmBtu, HHV)	0.0077	0.0081	0.0085
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)	1,314,153	1,251,028	1,181,580
Sulfur content (grains/ 100 cf)	2	2	2
lb SO_2 /lb S (64/32)	2	2	2
CT emission rate (lb/hr)	7.5	7.1	6.8
HRSG Stack emission rate (lb/hr)	7.5	7.1	6.8
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 flow (acfm) x 46 (mole. wgt NOx) x 60 min/hr / [1545 x (CT temp.(°F) + 460) x (20.9-15) x 1,000,000 (adj. for ppm)]			
CT / DB, ppmvd @15% O_2	9	9	9
Moisture (%)	7.52	8.32	9.54
Oxygen (%)	12.80	12.73	12.66
Turbine Flow (acfm)	1,880,545	1,843,332	1,803,432
Turbine Exhaust Temperature (°F)	1,167	1,190	1,200
CT Emission rate (lb/hr)	43.5	41.4	39.1
HRSG Stack emission rate, ppmvd @ 15% O_2	5	5	5
HRSG Stack emission rate (lb/hr)	24.2	23.0	21.7

TABLE A-6
MAXIMUM EMISSIONS FOR CRITERIA POLLUTANTS FOR THE HOPKINS UNIT 2 REPOWERING PROJECT
GE FRAME 7FA, DRY LOW NO_X COMBUSTOR, NATURAL GAS, 60% LOAD

Parameter	Turbine Inlet Temperature 25 °F	59 °F	95 °F
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	12	12	12
Moisture (%)	7.52	8.32	9.54
Turbine Flow (acfm)	1,880,545	1,843,332	1,803,432
Turbine Exhaust Temperature (°F)	1,167	1,190	1,200
HRSG Exhaust Temperature (°F)	175	178	182
CT Emission rate (lb/hr)	29.5	28.3	27.1
HRSG Stack emission rate (lb/hr)	29.5	28.3	27.1
Volatile Organic Compounds			
VOCs (lb/hr) = VOC(ppmvd) x [1-Moisture(%)/100] x 2116.8 lb/ft^2 x Volume flow (acfm) x 16 (mole. wgt as methane) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]			
Basis, ppmvw	3.50	3.5	3.50
Moisture (%)	7.52	8.32	9.54
Turbine Flow (acfm)	1,880,545	1,843,332	1,803,432
Turbine Exhaust Temperature (°F)	1,167	1,190	1,200
HRSG Exhaust Temperature (°F)	175	175	175
CT Emission rate (lb/hr)	5.32	5.14	5.00
HRSG Stack emission rate (lb/hr)	5.32	5.14	5.00
Sulfuric Acid Mist			
Sulfuric Acid Mist (lb/hr)= SO_2 emission (lb/hr) x Conversion to H_2SO_4 (% by weight)/100			
CT SO_2 emission rate (lb/hr) - provided	7.5	7.1	6.8
CT Conversion to H_2SO_4 (% by weight) - provided	10	10	10
DB SO_2 emission rate (lb/hr) - provided	0	0	0
DB Conversion to H_2SO_4 (%) - provided	20	20	20
CT Emission rate (lb/hr)	0.75	0.71	0.68
HRSG Stack emission rate (lb/hr)	0.75	0.71	0.68
Lead			
Lead (lb/hr) = NA			
Emission Rate Basis	NA	NA	NA
CT Emission rate (lb/hr)	NA	NA	NA
HRSG Stack emission rate (lb/hr)	NA	NA	NA

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

Source: GE, 2006 - CT Performance Data; Golder, 2006.

TABLE A-7
DESIGN INFORMATION AND STACK PARAMETERS FOR THE HOPKINS UNIT 2 REPOWERING PROJECT
GE FRAME 7FA, DRY LOW NO_X COMBUSTOR, DISTILLATE OIL, BASE LOAD, WITH NATURAL GAS DUCT FIRING

Parameter		CT Only Turbine Inlet Temperature			CT with Duct Burner (Natural Gas) Turbine Inlet Temperature		
		25 °F	59 °F	95 °F	25 °F w/DB	59 °F w/DB	95 °F w/DB
Combustion Turbine Performance							
Power output (MW)	p	198.9	187.9	172.4	198.9	187.9	172.4
Heat rate (Btu/kWh, LHV)	p	9,860	9,935	10,090	9,860	9,935	10,090
(Btu/kWh, HHV)		10,452	10,531	10,695	10,452	10,531	10,695
Heat Input (MMBtu/hr, LHV)	p	1,961.2	1,866.8	1,739.5	1,961.2	1,866.8	1,739.5
(MMBtu/hr, HHV)		2,079	1,979	1,844	2,079	1,979	1,844
Evaporative Cooler		Off	On	On	Off	On	On
Relative Humidity (%)	p	87	78	50	87.0	78.0	50.0
Fuel oil							
Fuel heating value (Btu/lb, LHV)	p	18,300	18,300	18,300	18,300	18,300	18,300
(Btu/lb, HHV)		19,398	19,398	19,398	19,398	19,398	19,398
(HHV/LHV)		1.060	1.060	1.060	1.060	1.060	1.060
Fuel heating value (Btu/lb, LHV)		NA	NA	NA	18,300	18,300	18,300
(Btu/lb, HHV)		NA	NA	NA	19,398	19,398	19,398
(HHV/LHV)		NA	NA	NA	1.11	1.11	1.11
Duct Burner (DB)							
Heat input (MMBtu/hr, HHV)		0	0	0	764.6	711.6	662.6
(MMBtu/hr, LHV)		0	0	0	688.8	641.1	596.9
CT Exhaust Flow							
Mass Flow (lb/hr)- with no margin		3,995,000	3,764,000	3,512,000	4,025,724	3,792,596	3,538,625
- provided	p	3,995,000	3,764,000	3,512,000			
Temperature (°F)	p	1,059	1,096	1,130	1,059	1,096	1,130
Moisture (% Vol.)	p	10.95	11.82	12.96	13.50	14.32	15.43
Oxygen (% Vol.)	p	11.20	10.97	10.77	8.35	8.16	7.98
Molecular Weight	c	28.36	28.26	28.13	28.19	28.10	27.97
	p	28.35	28.26	28.13			
Fuel Usage							
Fuel oil							
Fuel usage CT (lb/hr) = Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu (Fuel Heat Content, Btu/lb (LHV))							
Heat input (MMBtu/hr, LHV)		1,961	1,867	1,740	NA	NA	NA
Heat content (Btu/lb, LHV)		18,300	18,300	18,300	NA	NA	NA
Fuel usage (lb/hr)- calculated	c	107,169	102,011	95,055	NA	NA	NA
Natural gas							
Fuel usage DB (lb/hr) = Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu (Fuel Heat Content, Btu/lb (LHV))							
Heat input (MMBtu/hr, LHV)		NA	NA	NA	688.8	641.1	596.9
Heat content (Btu/lb, LHV)		NA	NA	NA	20,714	20,714	20,714
Fuel usage (lb/hr)- calculated		NA	NA	NA	33,253	30,950	28,816
Heat content (Btu/cf, LHV)- assumed		NA	NA	NA	933	933	933
Fuel density (lb/ft^3)		NA	NA	NA	0.0451	0.0451	0.0451
Fuel usage (cf/hr)- calculated		NA	NA	NA	737,941	686,838	639,485
Bypass Stack and Flow Conditions							
Stack Height (ft)		150	150	150	150	150	150
Diameter (ft)		18	18	18	18	18	18
Velocity (ft/sec) = Volume flow (acfm) / [((diameter)^2 /4) x 3.14159] / 60 sec/min							
Mass flow (lb/hr)		3,995,000	3,764,000	3,512,000	NA	NA	NA
Stack Temperature (°F)		1,059	1,096	1,130	NA	NA	NA
Molecular weight		28.36	28.26	28.13	NA	NA	NA
Volume flow (acfm)		2,603,400	2,520,733	2,414,634	NA	NA	NA
Diameter (ft)		18	18	18	NA	NA	NA
Velocity (ft/sec)- calculated		170.5	165.1	158.1	NA	NA	NA
HRSG Stack and Flow Conditions							
Stack Height (ft)		150	150	150	150	150	150
Diameter (ft)		18	18	18	18	18	18
Mass flow (lb/hr)		3,995,000	3,764,000	3,512,000	4,025,724	3,792,596	3,538,625
Stack Temperature (°F)		248.0	248.0	247.0	206	204	201
Molecular weight		28.36	28.26	28.13	28.19	28.10	27.97
Volume flow (acfm)		1,213,435	1,146,966	1,073,677	1,157,102	1,090,210	1,017,182
Diameter (ft)		18	18	18	18	18	18
Velocity (ft/sec)- calculated		79.5	75.1	70.3	75.8	71.4	66.6

Note: Universal gas constant = 1,545 ft-lb(force)/°R; atmospheric pressure = 2,116.8 lb(force)/ft^2; 14.7 lb/ft^3.

Source: GE, 2006 - CT Performance Data; Golder, 2006.

TABLE A-8
MAXIMUM EMISSIONS FOR CRITERIA POLLUTANTS HOPKINS UNIT 2 REPOWERING PROJECT
GE FRAME 7FA, DRY LOW NO_X COMBUSTOR, DISTILLATE OIL, BASE LOAD, WITH NATURAL GAS DUCT FIRING

	CT Only Turbine Inlet Temperature			CT with Duct Burner (Natural Gas) Turbine Inlet Temperature		
Parameter	25 °F	59 °F	95 °F	25 °F w/DB	59 °F w/DB	95 °F w/DB
Particulate from CTand SCR						
Total PM_{10} = PM_{10} (front half) + PM_{10} ($(NH_4)_2SO_4$) from SCR only						
a. PM_{10} (front half) (lb/hr)						
CT- provided	17.0	17.0	17.0	17.0	17.0	17.0
DB (lb/hr) - calculated	0.0	0.0	0.0	9.2	8.5	8.0
Total CT/DB emission rate (lb/hr)	17.0	17.0	17.0	26.2	25.5	25.0
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	107.2	102.0	95.1	111.4	105.9	98.7
Conversion (%) from SO_2 to SO_3	9.8	9.8	9.8	9.8	9.8	9.8
MW SO_3/ SO_2 (80/64)	1.3	1.3	1.3	1.3	1.3	1.3
Conversion (%) from SO_3 to $(NH_4)_2(SO_4)$	100	100	100	100	100	100
MW $(NH_4)_2$ SO_4/ SO_3 (132/80)	1.7	1.7	1.7	1.7	1.7	1.7
SCR Particulate (lb/hr)- calculated	21.66	20.62	19.21	22.51	21.41	19.95
CT emission rate (lb/hr) [a + b] assumes SCR	38.7	37.6	36.2	38.7	37.6	36.2
HRSG stack emission rate (lb/hr) [a + b]	38.7	37.6	36.2	48.7	47.0	44.9
(lb/mmBtu, HHV)	0.0186	0.0190	0.0196	0.0171	0.0175	0.0179
Sulfur Dioxide						
CT/SO_2 (lb/hr)= Fuel oil (lb/hr) x sulfur content(% weight) x (lb SO_2 /lb S) /100						
Fuel oil Sulfur Content	0.0500%	0.0500%	0.0500%	0.0500%	0.0500%	0.0500%
Fuel oil use (lb/hr)	107,169	102,011	95,055	NA	102,011	95,055
lb SO2 / lb S (64/32)	2	2	2	2	2	2
DB/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)	NA	NA	NA	737,941	686,838	639,485
Sulfur content (grains/ 100 cf)	NA	NA	NA	2	2	2
CT emission rate (lb/hr)	107.2	102.0	95.1	107.2	102.0	95.1
HRSG stack emission rate (lb/hr)	107.2	102.0	95.1	111.4	105.9	98.7
(lb/MW)	0.54	0.54	0.55			
Nitrogen Oxides						
NOx (lb/hr) = NOx (ppmvd@ 15% O_2) x {[20.9 x (1-Moisture (%)/100] - Oxygen, dry(%)} x 2116.8 lb/ft^2 x Volume flow (acfm) x 46 (mole. wgt NOx) x 60 min/hr / [1545 x (CT temp.(°F) + 460) x (20.9-15) x 1,000,000 (adj. for ppm)]						
CT/DB, ppmvd @15% O_2	42	42	42	38.6	38.7	38.7
Moisture (%)	10.95	11.82	12.96	13.50	14.32	15.43
Oxygen (%)	11.20	10.97	10.77	8.35	8.16	7.98
Turbine Flow (acfm)	2,603,400	2,520,733	2,414,634	2,639,095	2,554,769	2,446,776
Turbine Exhaust Temperature (°F)	1,059	1,096	1,130	1,059	1,096	1,130
CT emission rate (lb/hr)	341.9	325.3	303.4	418.4	396.5	369.6
(lb/MW)	1.7	1.7	1.8	NA	NA	NA
HRSG stack emission rate, ppmvd @ 15% O_2	10	10	10	10	10	10
HRSG stack emission rate (lb/hr)	81.4	77.5	72.2	108.4	102.6	95.6
(lb/MW)	0.41	0.41	0.42			
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	25	25	25	41.9	41.8	41.9
Basis, ppmvd @ 15% O_2	17.72	17.44	17.30	21.44	21.18	21.14
Moisture (%)	10.95	11.82	12.96	13.74	14.55	15.62
Oxygen (%)	11.20	10.97	10.77	8.07	7.90	7.76
Turbine Flow (acfm)	2,603,400	2,520,733	2,414,634	2,639,095	2,554,769	2,446,776
Turbine Exhaust Temperature (°F)	1,059	1,096	1,130	1,059	1,096	1,130
CT emission rate (lb/hr)	87.8	82.2	76.1	87.8	82.2	76.1
HRSG Stack emission rate (lb/hr)	87.8	82.2	76.1	142.9	133.4	123.8

TABLE A-8
MAXIMUM EMISSIONS FOR CRITERIA POLLUTANTS HOPKINS UNIT 2 REPOWERING PROJECT
GE FRAME 7FA, DRY LOW NO_X COMBUSTOR, DISTILLATE OIL, BASE LOAD, WITH NATURAL GAS DUCT FIRING

Parameter	CT Only Turbine Inlet Temperature			CT with Duct Burner (Natural Gas) Turbine Inlet Temperature		
	25 °F	59 °F	95 °F	25 °F w/DB	59 °F w/DB	95 °F w/DB
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	3.50	3.50	3.50	7.6	7.5	7.5
Basis, ppmvd	3.93	3.97	4.02	8.8	8.8	8.9
Basis, ppmvd @ 15% O_2	2.79	2.77	2.78	5.2	5.2	5.3
Moisture (%)	10.95	11.82	12.96	13.74	14.55	15.62
Oxygen (%)	11.20	10.97	10.77	8.07	7.90	7.76
Oxygen (%-dry)	12.58	12.44	12.37	9.36	9.25	9.20
Turbine Flow (acfm)	2,603,400	2,520,733	2,414,634	2,639,095	2,554,769	2,446,776
Turbine Exhaust Temperature (°F)	1,059	1,096	1,130	1,059	1,096	1,130
CT emission rate (lb/hr)	7.89	7.46	6.99	7.89	7.46	6.99
HRSG Stack emission rate (lb/hr)	7.89	7.46	6.99	17.1	16.0	14.9
Sulfuric Acid Mist						
Sulfuric Acid Mist (lb/hr)= SO_2 emission (lb/hr) x Conversion to H_2SO_4 (% by weight)/100						
CT SO_2 emission rate (lb/hr) - provided	107.2	102.0	95.1	111.4	105.9	98.7
CT Conversion to H_2SO_4 (% by weight)	20	20	20	20	20	20
DB SO_2 emission rate (lb/hr) - provided	0	0	0	0.0	0.0	0.0
DB Conversion to H_2SO_4 (%) - provided	20	20	20	20	20	20
CT emission rate (lb/hr)	21.4	20.4	19.0	21.4	20.4	19.0
HRSG Stack emission rate (lb/hr)	21.4	20.4	19.0	22.3	21.2	19.7
Lead						
Lead (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu						
Emission Rate Basis (lb/10^{12} Btu)	14	14	14	14	14	14
CT emission rate (lb/hr)	0.0291	0.0277	0.0258	0.0291	0.0277	0.0258
HRSG stack Emission rate (lb/hr)	0.0291	0.0277	0.0258	0.0291	0.0277	0.0258

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

Source: GE, 2006 - CT Performance Data; Golder, 2006.

TABLE A-9
DESIGN INFORMATION AND STACK PARAMETERS FOR THE HOPKINS UNIT 2 REPOWERING PROJECT
GE FRAME 7FA, DRY LOW NO_X COMBUSTOR, DISTILLATE OIL, 75% LOAD

Parameter	Turbine Inlet Temperature 25 °F	59 °F	95 °F
Combustion Turbine Performance			
Power output (MW)	149.2	140.9	129.3
Heat rate (Btu/kWh, LHV)	10,580	10,740	10,940
(Btu/kWh, HHV)	11,215	11,385	11,596
Heat Input (MMBtu/hr, LHV)	1,579	1,513	1,415
(MMBtu/hr, HHV)	1,673	1,604	1,499
Relative Humidity (%)	87	78	50
Fuel heating value (Btu/lb, LHV)	18,300	18,300	18,300
(Btu/lb, HHV)	19,398	19,398	19,398
(HHV/LHV)	1.060	1.060	1.060
CT Exhaust Flow			
Mass Flow (lb/hr)- with no margin	3,085,000	2,993,000	2,848,000
- provided	3,085,000	2,993,000	2,848,000
Temperature (°F)	1,136	1,159	1,184
Moisture (% Vol.)	10.91	11.46	12.22
Oxygen (% Vol.)	10.96	10.96	10.96
Molecular Weight	28.38	28.31	28.21
Fuel Usage			
Fuel usage (lb/hr) = Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu (Fuel Heat Content, Btu/lb (LHV))			
Heat input (MMBtu/hr, LHV)	1,579	1,513	1,415
Heat content (Btu/lb, LHV)	18,300	18,300	18,300
Fuel usage (lb/hr)- calculated	86,257	82,694	77,295
HRSG Stack and Flow Conditions			
Stack Height (ft)	150	150	150
Diameter (ft)	18	18	18
Velocity (ft/sec) = Volume flow (acfm) / [((diameter)² /4) x 3.14159] / 60 sec/min			
Mass flow (lb/hr)	3,085,000	2,993,000	2,848,000
Stack Temperature (oF)	233	233	232
Molecular weight	28.38	28.31	28.21
Volume flow (acfm)	916,430	891,229	849,841
Diameter (ft)	18	18	18
Velocity (ft/sec)- calculated	60.0	58.4	55.7

Note: Universal gas constant = 1,545 ft-lb(force)/°R; atmospheric pressure = 2,116.8 lb(force)/ft²; 14.7 lb/ft^3.

Source: GE, 2006 - CT Performance Data; Golder, 2006.

TABLE A-10
MAXIMUM EMISSIONS FOR CRITERIA POLLUTANTS FOR THE HOPKINS UNIT 2 REPOWERING PROJECT
GE FRAME 7FA, DRY LOW NO_X COMBUSTOR, DISTILLATE OIL, 75% LOAD

Parameter	Turbine Inlet Temperature 25 °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) (lb/hr)			
CT- 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	86.3	82.7	77.3
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	17.43	16.71	15.62
CT emission rate (lb/hr) [a]	17.0	17.0	17.0
HRSG stack emission rate (lb/hr) [a + b]	34.4	33.7	32.6
(lb/mmBtu, HHV)	0.0206	0.0210	0.0218
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	0.050%	0.050%	0.050%
Fuel oil use (lb/hr)	86,257	82,694	77,295
lb SO2 / lb S (64/32)	2	2	2
CT emission rate (lb/hr)	86.3	82.7	77.3
HRSG Stack emission rate (lb/hr)	86.3	82.7	77.3
Nitrogen Oxides			
NOx (lb/hr) = NOx (ppmvd@ 15% O_2) x {[20.9 x (1-Moisture (%)/100] - Oxygen, dry(%)} x 2116.8 lb/ft^2 x Volume flow (acfm) x 46 (mole. wgt NOx) x 60 min/hr / [1545 x (CT temp.(°F) + 460) x (20.9-15) x 1,000,000 (adj. for ppm)]			
CT/DB, ppmvd @15% O_2	42	42	42
Moisture (%)	10.91	11.46	12.22
Oxygen (%)	10.96	10.96	10.96
Turbine Flow (acfm)	2,110,565	2,082,106	2,018,987
Turbine Exhaust Temperature (°F)	1,136	1,159	1,184
CT Emission rate (lb/hr)	272.7	261.2	244.2
HRSG Stack emission rate, ppmvd @ 15% O_2	10	10	10.0
HRSG Stack emission rate (lb/hr)	64.9	62.2	58.1
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	25	25	25
Moisture (%)	10.91	11.46	12.22
Turbine Flow (acfm)	2,110,565	2,082,106	2,018,987
Turbine Exhaust Temperature (°F)	1,136	1,159	1,184
HRSG Exhaust Temperature (°F)	233	233	232
CT Emission rate (lb/hr)	67.8	65.5	62.0
HRSG Stack emission rate (lb/hr)	67.8	65.5	62.0

TABLE A-10
MAXIMUM EMISSIONS FOR CRITERIA POLLUTANTS FOR THE HOPKINS UNIT 2 REPOWERING PROJECT
GE FRAME 7FA, DRY LOW NO_X COMBUSTOR, DISTILLATE OIL, 75% LOAD

Parameter	Turbine Inlet Temperature 25 °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
Moisture (%)	10.91	11.46	12.22
Turbine Flow (acfm)	10.96	10.96	10.96
Turbine Exhaust Temperature (°F)	2,110,565	2,082,106	2,018,987
HRSG Exhaust Temperature (°F)	1,136	1,159	1,184
CT Emission rate (lb/hr)	6.09	5.92	5.65
HRSG Stack emission rate (lb/hr)	6.09	5.92	5.65
Sulfuric Acid Mist			
Sulfuric Acid Mist (lb/hr)= SO_2 emission (lb/hr) x Conversion to H_2SO_4 (% by weight)/100			
CT SO_2 emission rate (lb/hr) - provided	86.3	82.7	77.3
CT Conversion to H_2SO_4 (% by weight) - provided	20	20	20
DB SO_2 emission rate (lb/hr) - provided	0	0	0
DB Conversion to H_2SO_4 (%) - provided	20	20	20
CT Emission rate (lb/hr)	17.25	16.54	15.46
HRSG Stack emission rate (lb/hr)	17.25	16.54	15.46
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
CT Emission rate (lb/hr)	0.0221	0.0212	0.0198
HRSG Stack emission rate (lb/hr)	0.0221	0.0212	0.0198

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

Source: GE, 2006 - CT Performance Data; Golder, 2006.

TABLE A-11
DESIGN INFORMATION AND STACK PARAMETERS FOR THE HOPKINS UNIT 2 REPOWERING PROJECT
GE FRAME 7FA, DRY LOW NO_X COMBUSTOR, DISTILLATE OIL, 60% LOAD

Parameter	Turbine Inlet Temperature 25 °F	59 °F	95 °F
Combustion Turbine Performance			
Power output (MW)	119.4	112.7	103.5
Heat rate (Btu/kWh, LHV)	11,570	11,750	12,010
(Btu/kWh, HHV)	12,265	12,455	12,730
Heat Input (MMBtu/hr, LHV)	1,382	1,324	1,243
(MMBtu/hr, HHV)	1,464	1,404	1,318
Relative Humidity (%)	87	78	50
Fuel heating value (Btu/lb, LHV)	18,300	18,300	18,300
(Btu/lb, HHV)	19,398	19,398	19,398
(HHV/LHV)	1.060	1.060	1.060
CT Exhaust Flow			
Mass Flow (lb/hr)- with no margin	2,743,000	2,667,000	2,579,000
- provided	2,743,000	2,667,000	2,579,000
Temperature (°F)	1,167	1,188	1,200
Moisture (% Vol.)	10.42	10.96	11.63
Oxygen (% Vol.)	11.23	11.23	11.33
Molecular Weight	28.42	28.35	28.25
Fuel Usage			
Fuel usage (lb/hr) = Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu (Fuel Heat Content, Btu/lb (LHV))			
Heat input (MMBtu/hr, LHV)	1,382	1,324	1,243
Heat content (Btu/lb, LHV)	18,300	18,300	18,300
Fuel usage (lb/hr)- calculated	75,492	72,361	67,923
HRSG Stack and Flow Conditions			
Stack Height (ft)	150	150	150
Diameter (ft)	18	18	18
Velocity (ft/sec) = Volume flow (acfm) / [((diameter)² /4) x 3.14159] / 60 sec/min			
Mass flow (lb/hr)	2,743,000	2,667,000	2,579,000
Stack Temperature (oF)	223	223	222
Molecular weight	28.42	28.35	28.25
Volume flow (acfm)	802,010	781,670	757,255
Diameter (ft)	18	18	18
Velocity (ft/sec)- calculated	52.5	51.2	49.6

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

Source: GE, 2006 - CT Performance Data; Golder, 2006.

TABLE A-12
MAXIMUM EMISSIONS FOR CRITERIA POLLUTANTS FOR THE HOPKINS UNIT 2 REPOWERING PROJECT
GE FRAME 7FA, DRY LOW NO_X COMBUSTOR, DISTILLATE OIL, 60% LOAD

Parameter	Turbine Inlet Temperature 25 °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) (lb/hr)			
CT- 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	75.5	72.4	67.9
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	15.26	14.63	13.73
CT emission rate (lb/hr) [a]	17.0	17.0	17.0
HRSG stack emission rate (lb/hr) [a + b]	32.3	31.6	30.7
(lb/mmBtu, HHV)	0.0220	0.0225	0.0233
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	0.050%	0.050%	0.050%
Fuel oil use (lb/hr)	75,492	72,361	67,923
lb SO2 / lb S (64/32)	2	2	2
CT emission rate (lb/hr)	75.5	72.4	67.9
HRSG Stack emission rate (lb/hr)	75.5	72.4	67.9
Nitrogen Oxides			
NOx (lb/hr) = NOx (ppmvd@ 15% O_2) x {[20.9 x (1-Moisture (%)/100] - Oxygen, dry(%)} x 2116.8 lb/ft^2 x Volume flow (acfm) x 46 (mole. wgt NOx) x 60 min/hr / [1545 x (CT temp.(°F) + 460) x (20.9-15) x 1,000,000 (adj. for ppm)]			
CT/DB, ppmvd @15% O_2	42	42	42
Moisture (%)	10.42	10.96	11.63
Oxygen (%)	11.23	11.23	11.33
Turbine Flow (acfm)	1,910,499	1,886,080	1,843,173
Turbine Exhaust Temperature (°F)	1,167	1,188	1,200
CT Emission rate (lb/hr)	236.8	227.3	213.4
HRSG Stack emission rate, ppmvd @ 15% O_2	10	10	10.0
HRSG Stack emission rate (lb/hr)	56.4	54.1	50.8
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	25	25	25
Moisture (%)	10.42	10.96	11.63
Turbine Flow (acfm)	1,910,499	1,886,080	1,843,173
Turbine Exhaust Temperature (°F)	1,167	1,188	1,200
HRSG Exhaust Temperature (°F)	28	28	28
CT Emission rate (lb/hr)	60.5	58.6	56.5
HRSG Stack emission rate (lb/hr)	60.5	58.6	56.5

TABLE A-12

MAXIMUM EMISSIONS FOR CRITERIA POLLUTANTS FOR THE HOPKINS UNIT 2 REPOWERING PROJECT

GE FRAME 7FA, DRY LOW NO_X COMBUSTOR, DISTILLATE OIL, 60% LOAD

Parameter	Turbine Inlet Temperature 25 °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
Moisture (%)	10.42	10.96	11.63
Turbine Flow (acfm)	11.23	11.23	11.33
Turbine Exhaust Temperature (°F)	1,910,499	1,886,080	1,843,173
HRSG Exhaust Temperature (°F)	1,167	1,188	1,200
CT Emission rate (lb/hr)	5.41	5.27	5.11
HRSG Stack emission rate (lb/hr)	5.41	5.27	5.11
Sulfuric Acid Mist			
Sulfuric Acid Mist (lb/hr)= SO_2 emission (lb/hr) x Conversion to H_2SO_4 (% by weight)/100			
CT SO_2 emission rate (lb/hr) - provided	75.5	72.4	67.9
CT Conversion to H_2SO_4 (% by weight) - provided	20	20	20
DB SO_2 emission rate (lb/hr) - provided	0	0	0
DB Conversion to H_2SO_4 (%) - provided	20	20	20
CT Emission rate (lb/hr)	15.10	14.47	13.58
HRSG Stack emission rate (lb/hr)	15.10	14.47	13.58
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
CT Emission rate (lb/hr)	0.0193	0.0185	0.0174
HRSG Stack emission rate (lb/hr)	0.0193	0.0185	0.0174

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

Source: GE, 2006 - CT Performance Data; Golder, 2006.

TABLE A-13
DUCT BURNER EMISSIONS: FULL DUCT FIRING

Pollutant	Emission Rate (lb/MMBtu)	AP-42	Heat Input (MMBtu/hr) (HHV) 25 °F	59 °F	95 °F	Emission Rate (lb/hr) 25 °F	59 °F	95 °F
Natural Gas-Firing								
PM-10	0.012		765	712	663	9.2	8.5	8.0
NO_x	0.10		765	712	663	76.5	71.2	66.3
CO	0.072		765	712	663	55.0	51.2	47.7
VOC	0.012		765	712	663	9.2	8.5	8.0

Natural gas-firing	AP-42 (1998)		
PM-10	1.9 lb/10^6 scf	a	0.0018 lb/MMBtu
NOx	190 lb/10^6 scf	b	0.183 lb/MMBtu
CO	84 lb/10^6 scf	b	0.081 lb/MMBtu
VOC	5.5 lb/10^6 scf	a	0.0053 lb/MMBtu

Heat content 1036 Btu/scf

[a] Table 1.4-2. Emission Factors for Criteria Pollutants and Greenhouse Gases from Natural Gas Combustion, Uncontrolled Post-NSPS

[b] Table 1.4-1. Emission Factors for Nitrogen Oxides (NOx) and Carbon Monoxide (CO) from Natural Gas Combustion

TABLE A-14
REGULATED AND HAZARDOUS AIR POLLUTANT EMISSION FACTORS AND EMISSIONS
FOR HOPKINS UNIT 2 REPOWERING PROJECT, NATURAL GAS-FIRING ONLY

Parameter	Emission Rate (lb/hr) firing Natural Gas for Operating Conditions of Base Load [a]		Natural Gas Maximum Annual Emissions (TPY) [b]
Ambient Temperature (°F):	59 °F	59 °F w/DB	59 °F
HIR (MMBtu/hr):	1,795	2,506	1 CT/HRSG
HAPs (Section 112(b) of Clean Air Act)			
1,3-Butadiene	7.72E-04	1.08E-03	4.18E-03
Acetaldehyde	7.18E-02	1.00E-01	3.89E-01
Acrolein	1.15E-02	1.60E-02	6.23E-02
Benzene	2.15E-02	3.01E-02	1.17E-01
Ethylbenzene	5.74E-02	8.02E-02	3.11E-01
Formadehyde	3.85E-01	5.34E-01	2.08E+00
Naphthalene	2.33E-03	3.26E-03	1.27E-02
Polycyclic Aromatic Hydrocarbons (PAH) [c]	3.95E-03	5.51E-03	2.14E-02
Propylene Oxide	5.20E-02	7.27E-02	2.82E-01
Toluene	5.92E-02	8.27E-02	3.21E-01
Xylene	1.15E-01	1.60E-01	6.23E-01
Antimony	0.00E+00	0.00E+00	0.00E+00
Arsenic	0.00E+00	0.00E+00	0.00E+00
Beryllium	0.00E+00	0.00E+00	0.00E+00
Cadmium	0.00E+00	0.00E+00	0.00E+00
Chromium	0.00E+00	0.00E+00	0.00E+00
Lead	0.00E+00	0.00E+00	0.00E+00
Manganese	0.00E+00	0.00E+00	0.00E+00
Mercury	0.00E+00	0.00E+00	0.00E+00
Nickel	0.00E+00	0.00E+00	0.00E+00
Selenium	0.00E+00	0.00E+00	0.00E+00
HAPs (Total)	0.780	1.086	4.22

[a] Emissions based on the following emission factors and conversion factors for firing natural gas:

Emission Factors		Value	Reference
1,3-Butadiene	(a)	0.43	lb/10^{12} Btu; AP-42,Table 3.1-3. EPA 2000
Acetaldehyde		40	lb/10^{12} Btu; AP-42,Table 3.1-3. EPA 2000
Acrolein		6.4	lb/10^{12} Btu; AP-42,Table 3.1-3. EPA 2000
Benzene		12	lb/10^{12} Btu; AP-42,Table 3.1-3. EPA 2000
Ethylbenzene		32	lb/10^{12} Btu; AP-42,Table 3.1-3. EPA 2000
Formadehyde		0.091	ppmvd @15% O_2 (see Table 15a)
Naphthalene		1.3	lb/10^{12} Btu; AP-42,Table 3.1-3. EPA 2000
Polycyclic Aromatic Hydrocarbons (PAH)		2.2	lb/10^{12} Btu; AP-42,Table 3.1-3. EPA 2000
Propylene Oxide	(a)	29	lb/10^{12} Btu; AP-42,Table 3.1-3. EPA 2000
Toluene		33	lb/10^{12} Btu; AP-42,Table 3.1-3. EPA 2000. Database
Xylene		64	lb/10^{12} Btu; AP-42,Table 3.1-3. EPA 2000
Antimony		0.00E+00	
Arsenic		0.00E+00	
Beryllium		0.00E+00	
Cadmium		0.00E+00	
Chromium		0.00E+00	
Lead		0.00E+00	
Manganese		0.00E+00	
Mercury		0.00E+00	
Nickel		0.00E+00	
Selenium		0.00E+00	

(a) Based on 1/2 the detection limit; expected emissions are lower.

[b] Annual emissions based on ambient temperature of 59 °F firing natural gas for following hours:
3,500 hours, NG w/o duct firing
5,260 hours, NG w/ duct firing

[c] Assumed to be representative of Polycyclic Organic Matter (POM) emissions, a regulated HAP.

TABLE A-15
MAXIMUM FORMALDEHYDE EMISSIONS FOR THE HOPKINS UNIT 2 REPOWERING PROJECT
GE FRAME 7FA, DRY LOW NO_X COMBUSTOR, NATURAL GAS, BASE LOAD

Parameter	CT Only Turbine Inlet Temperature 25 °F	59 °F	25 °F w/DB	59 °F w/DB
Formaldehyde (CH_2O) MW = 30				
CH_2O (lb/hr) = CH_2O (ppmvd@ 15% O2) x {[20.9 x (1-Moisture (%)/100] - Oxygen, dry(%)} x 2116.8 lb/ft2 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	0.091
Moisture (%)	7.54	8.55	10.26	11.21
Oxygen (%)	12.77	12.57	9.76	9.61
Turbine Flow (acfm)	1,083,262	1,023,573	1,075,526	1,016,095
Turbine Exhaust Temperature (°F)	203	202	189	188
CT Emission rate (lb/hr)	0.407	0.385	0.567	0.534
CT Emission rate (lb/10^{12} Btu) (HHV)	214.5	214.4	213.0	200.4

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

Source: GE, 2006 - CT Performance Data; Golder, 2006.

TABLE A-16
REGULATED AND HAZARDOUS AIR POLLUTANT EMISSION FACTORS AND EMISSIONS FOR THE HOPKINS UNIT 2 REPOWERING PROJECT
NATURAL GAS-FIRING AND DISTILLATE OIL-FIRING

Parameter	Emission Rate (lb/hr) Firing Distillate Fuel Oil [a] Base Load	Maximum Annual Emissions (TPY)		
Ambient Temperature (°F):	59 °F	Distillate Fuel Oil [b] 1	Natural Gas [d] 1	Natural Gas and Fuel Oil [e]
HIR (MMBtu/hr):	1,979	CT/HRSG	CT/HRSG	
HAPs (Section 112(b) of Clean Air Act)				
1,3-Butadiene	3.17E-02	3.17E-02	4.18E-03	3.45E-02
Acetaldehyde	0.00E+00	0.00E+00	3.89E-01	2.64E-01
Acrolein	0.00E+00	0.00E+00	6.23E-02	4.22E-02
Benzene	1.09E-01	1.09E-01	1.17E-01	1.88E-01
Ethylbenzene	0.00E+00	0.00E+00	3.11E-01	2.11E-01
Formadehyde	4.60E-01	4.60E-01	2.08E+00	1.86E+00
Naphthalene	6.93E-02	6.93E-02	1.27E-02	7.78E-02
Polycyclic Aromatic Hydrocarbons (PAH) [c]	7.92E-02	7.92E-02	2.14E-02	9.37E-02
Propylene Oxide	0.00E+00	0.00E+00	2.82E-01	1.91E-01
Toluene	0.00E+00	0.00E+00	3.21E-01	2.18E-01
Xylene	0.00E+00	0.00E+00	6.23E-01	4.22E-01
Antimony	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Arsenic	2.18E-02	2.18E-02	0.00E+00	2.18E-02
Beryllium	6.13E-04	6.13E-04	0.00E+00	6.13E-04
Cadmium	9.50E-03	9.50E-03	0.00E+00	9.50E-03
Chromium	2.18E-02	2.18E-02	0.00E+00	2.18E-02
Lead	2.77E-02	2.77E-02	0.00E+00	2.77E-02
Manganese	1.56E+00	1.56E+00	0.00E+00	1.56E+00
Mercury	2.37E-03	2.37E-03	0.00E+00	2.37E-03
Nickel	9.10E-03	9.10E-03	0.00E+00	9.10E-03
Selenium	4.95E-02	4.95E-02	0.00E+00	4.95E-02
HAPs (Total)	2.45	1.64	4.2	5.3

[a] Emissions based on the following emission factors and conversion factors for firing distillate fuel oil:

Emission Factors		Valu	Reference
Sulfuric acid mist		5	%; Conversion of SO_2 to SO_3 in gas turbine
1,3-Butadiene	(a)	16	lb/10^{12} Btu; AP-42,Table 3.1-4. EPA 2000
Acetaldehyde		0.0	
Acrolein		0.0	
Benzene		55	lb/10^{12} Btu; AP-42,Table 3.1-4. EPA 2000
Ethylbenzene		0.0	
Formadehyde		###	ppmvd @15% O_2 (see Table 16a)
Naphthalene		35	lb/10^{12} Btu; AP-42,Table 3.1-4. EPA 2000
Polycyclic Aromatic Hydrocarbons (PAH)		40	lb/10^{12} Btu; AP-42,Table 3.1-4. EPA 2000
Propylene Oxide		0.0	
Toluene		0.0	
Xylene		0.0	
Antimony		0.0	
Arsenic	(a)	11	lb/10^{12} Btu; AP-42,Table 3.1-5. EPA 2000
Beryllium	(a)	0.3	lb/10^{12} Btu; AP-42,Table 3.1-5. EPA 2000
Cadmium		4.8	lb/10^{12} Btu; AP-42,Table 3.1-5. EPA 2000
Chromium		11	lb/10^{12} Btu; AP-42,Table 3.1-5. EPA 2000
Lead		14	lb/10^{12} Btu; AP-42,Table 3.1-5. EPA 2000
Manganese		790	lb/10^{12} Btu; AP-42,Table 3.1-5. EPA 2000
Mercury		1.2	lb/10^{12} Btu; AP-42,Table 3.1-5. EPA 2000
Nickel	(a)	4.6	lb/10^{12} Btu; AP-42,Table 3.1-5. EPA 2000
Selenium	(a)	25	lb/10^{12} Btu; AP-42,Table 3.1-5. EPA 2000

(a) Based on 1/2 the detection limit; expected emissions are lower.

[b] Annual emissions based on ambient temperature of 59 °F and firing fuel oil at base load for : 3,500 hours, FO w/o duct firing

[c] Assumed to be representative of Polycyclic Organic Matter (POM) emissions, a regulated HAP.

[d] Annual emissions based on maximum emissions presented for natural gas-firing
3,500 hours, NG w/o duct firing
5,260 hours, NG w/ duct firing

[e] Maximum total annual emissions based on maximum oil-firing and natural gas firing:
0 hours, NG w/o duct firing
5,260 hours, NG w/ duct firing

TABLE A-17
MAXIMUM FORMALDEHYDE EMISSIONS FOR THE HOPKINS UNIT 2 REPOWERING PROJECT
GE FRAME 7FA, DRY LOW NO_X COMBUSTOR, DISTILLATE OIL, BASE LOAD

Parameter	CT Only Turbine Inlet Temperature 25 °F	 59 °F
Formaldehyde (CH_2O) MW = 30		
CH_2O (lb/hr) = CH_2O (ppmvd@ 15% O2) x {[20.9 x (1-Moisture (%)/100] - Oxygen, dry(%)} x 2116.8 lb/ft2 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
Moisture (%)	10.95	11.82
Oxygen (%)	11.20	10.97
Exhaust Flow (acfm)	1,213,435	1,146,966
Exhaust Temperature (°F)	248	248
CT Emission rate (lb/hr)	0.483	0.460
CT Emission rate (lb/10^{12} Btu) (HHV)	232.4	232.3

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

Source: GE, 2006 - CT Performance Data; Golder, 2006.