



REPORT

PREVENTION OF SIGNIFICANT DETERIORATION APPLICATION FOR

THE EFFINGHAM PLANT EXPANSION PROJECT

EFFINGHAM COUNTY, GEORGIA

Mackinaw Power

Prepared For: Mackinaw Power
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July 2010

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APPLICATION

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List of Acronyms and Abbreviations

AAC	acceptable ambient concentration
AAQS	ambient air quality standard
acfm	actual cubic feet per minute
ACGIH	American Conference of Government Industrial Hygienists
AERMOD	American Meteorological Society and EPA Regulatory Model
AIG	ammonia injection grid
AQRV	air quality-related value/visibility test
BACT	best available control technology
bhp	brake horsepower
BPIP	Building Profile Input Program
Btu/lb	British thermal units per pound
Btu/scf	British thermal units per standard cubic feet
°C	degrees Celsius
CAA	Clean Air Act
CAIR	clean air interstate rule
CEM	continuous emission monitoring
CFR	Code of Federal Regulations
CH ₄	methane
CLS	Charleston International Airport
CO	carbon monoxide
CO ₂	carbon dioxide
CO ₂ e	carbon dioxide equivalent
CT	combustion turbine
DAT	deposition analysis thresholds
DLN	dry low-NO _x
EPA	US Environmental Protection Agency
EPD	(Georgia) Environmental Protection Division
EPRI	Electric Power Research Institute
ESP	electrostatic precipitator
°F	degrees Fahrenheit
F.A.C.	Florida Administrative Code
FGR	flue gas recirculation
FLAG	Federal Land Manager's Air Quality Relative Values Workgroup
FLM	Federal Land Manager
ft	foot
ft-msl	feet above mean sea level
g/kW-hr	grams per kilowatt-hour
gal	gallons
gal/day	gallons per day
gal/yr	gallons per year
GAQM	Guideline on Air Quality Models
GCP	good combustion practices
GE	General Electric
GEP	good engineering practice
GHG	greenhouse gases
GP	Georgia-Pacific
gpm	gallons per minute
g/s	grams per second
H ₂	hydrogen
H ₂ O	water
HAP	hazardous air pollutants
HC	hydrocarbons
Hg	mercury
HHV	high-heating value
hr/yr	hours per year

SHH	highest, second-highest
ID	inside diameter
IWAQM	Interagency Workgroup on Air Quality Models
K ₂ CO ₃	potassium carbonate
KNO ₃	potassium nitrate
KHI	Kawasaki Heavy Industries Ltd.
km	kilometer
kW	kilowatt
kW-hr	kilowatt-hour
kW-hr/yr	kilowatt-hours per year
kPa	kilopascals
LAER	lowest achievable emission rate
lb/hr	pounds per hour
lb/MMBtu	pound per million British thermal units
lb/MW-hr	pound per megawatt hour
LNB	low-NO _x burner
m ³	cubic meter
mg/m ³	milligrams per cubic meter
MACT	maximum achievable control technology
MMBtu/hr	British thermal unit per hour
msl	mean sea level
MW	megawatt
N ₂	nitrogen
N ₂ O	nitrous oxide
NAD83	North American Datum 1983
NED	National Elevation Dataset
NESHAP	National Emission Standards for Hazardous Air Pollutants
NH ₃	ammonia
NO	nitric oxide
NO ₂	nitrogen dioxide
NO _x	nitrogen oxides
NPS	National Park Service
NSCR	non-selective catalytic reduction
NSPS	new source performance standards
NSR	new source review
NWA	national wildlife area
NWS	National Weather Service
O ₂	oxygen
O ₃	ozone
OLM	Ozone Limiting Method
OSHA	Occupational Health and Safety Administration
Pb	lead
PEM	predictive emission monitor
PM	particulate matter
PM ₁₀	particulate matter less than 10 microns
PM _{2.5}	particulate matter less than 2.5 microns
ppm	parts per million
ppmvd	parts per million, by volume dry
PRIME	Plume Rise Model Enhancement
PSD	prevention of significant deterioration
PVMM	Plume Volume Molar Ratio Method
QA/QC	quality assurance/quality control
RBAC	risk-based air concentrations
RBL	RACT/BACT/LAER Clearinghouse
RfC	reference concentration
SAM	sulfuric acid mist
SAV	Savannah International Airport

APPLICATION

SIP AIR PERMIT APPLICATION

EPD Use Only

Date Received:

Application No.

FORM 1.00: GENERAL INFORMATION

1. Facility Information

Facility Name: Effingham County Power Plant

AIRS No. (if known): 04-13- 103 - 00012

Facility Location: Street: 3440 McCall Road

City: Rincon Georgia Zip: 31326 County: Effingham

2. Facility Coordinates

Latitude: 32° 16' 43" **NORTH** Longitude: 81° 17' 01" **WEST**

UTM Coordinates: EAST

NORTH

ZONE

3. Facility Owner

Name of Owner: Effingham County Power, LLC

Owner Address Street: 3440 McCall Road

City: Rincon State: Georgia Zip: 31326

4. Permitting Contact and Mailing Address

Contact Person: Matthew Lydon

Title: EH&S Manager

Telephone No.: (912) 826-3277

Ext.

Fax No.: (912) 826-3203

Email Address: mlydon@camsops.com

Mailing Address: Same as: Facility Location: ☒Owner Address: Other: ☐

If Other: Street Address:

City: _____ State: _____ Zip: _____

5. Authorized Official

Name: R. Eric Garrett

Title: General Manager

Address of Official Street: 3440 McCall Road

City: Rincon State: Georgia Zip: 31326

This application is submitted in accordance with the provisions of the Georgia Rules for Air Quality Control and, to the best of my knowledge, is complete and correct.

Signature:

Date: 7/22/10

6. Reason for Application: (Check all that apply)

- ☐ New Facility (to be constructed)
 ☐ Revision of Data Submitted in an Earlier Application
☒ Existing Facility (initial or modification application)
 Application No.: _____
☒ Permit to Construct
 Date of Original Submittal: _____
☐ Permit to Operate
☐ Change of Location
☐ Permit to Modify Existing Equipment:
 Affected Permit No.: _____

7. Permitting Exemption Activities (for permitted facilities only):

Have any exempt modifications based on emission level per Georgia Rule 391-3-1-.03(6)(i)(3) been performed at the facility that have not been previously incorporated in a permit?

- ☒ **No**
☐ **Yes, please fill out the SIP Exemption Attachment** (See Instructions for the attachment download)

8. Has assistance been provided to you for any part of this application?

- ☐ **No**
☐ **Yes, SBAP**
☒ **Yes, a consultant has been employed or will be employed.**

If yes, please provide the following information:

Name of Consulting Company: Golder Associates, Inc.
 Name of Contact: Sal Mohammad and Robert C. McCann, Jr.
 Telephone No.: (352) 336-5600 Fax No.: (352) 336-6603
 Email Address: smohammad@golder.com and bmccann@golder.com
 Mailing Address: Street: 6026 NW 1st Place
 City: Gainesville State: FL Zip: 32607

Describe the Consultant's Involvement:

Prepare permit application, control technology analysis, air dispersion modeling, air toxics analysis, prepare PSD report, and other related analysis.

9. Submitted Application Forms: Select only the necessary forms for the facility application that will be submitted.

No. of Forms	Form
1	2.00 Emission Unit List
1	2.01 Boilers and Fuel Burning Equipment
1	2.02 Storage Tank Physical Data
	2.03 Printing Operations
	2.04 Surface Coating Operations
	2.05 Waste Incinerators (solid/liquid waste destruction)
	2.06 Manufacturing and Operational Data
1	3.00 Air Pollution Control Devices (APCD)
	3.01 Scrubbers
	3.02 Baghouses & Other Filter Collectors
	3.03 Electrostatic Precipitators
1	4.00 Emissions Data
1	5.00 Monitoring Information
	6.00 Fugitive Emission Sources
1	7.00 Air Modeling Information

10. Construction or Modification Date

Estimated Start Date: July 2011

11. If confidential information is being submitted in this application, were the guidelines followed in the "Procedures for Requesting that Submitted Information be treated as Confidential"?

☐ No ☐ Yes ☒ N/A

12. New Facility Emissions Summary

Criteria Pollutant	New Facility	
	Potential (tpy)	Actual (tpy)
Carbon monoxide (CO)	537.1	537.1
Nitrogen oxides (NOx)	282.3	282.3
Particulate Matter (PM)	112.3	112.3
PM <10 microns (PM10)	111.4	111.4
PM <2.5 microns (PM2.5)	108.7	108.7
Sulfur dioxide (SO ₂)	25.3	25.3
Volatile Organic Compounds (VOC)	46.3	46.3
Total Hazardous Air Pollutants (HAPs)	10.8	10.8
Individual HAPs Listed Below:		
See Table A15 of Attachment A		

13. Existing Facility Emissions Summary

Criteria Pollutant	Current Facility		After Modification	
	Potential (tpy)	Actual (tpy)	Potential (tpy)	Actual (tpy)
Carbon monoxide (CO)	292	224.1	829.1	761.2
Nitrogen oxides (NOx)	222	109.2	504.3	391.5
Particulate Matter (PM)	96	59.3	208.3	171.6
PM <10 microns (PM10)	92	56.8	203.4	168.2
PM <2.5 microns (PM2.5)	92	56.8	200.7	165.5
Sulfur dioxide (SO ₂)	10	5.2	35.3	30.5
Volatile Organic Compounds (VOC)	27	16.2	73.3	62.5
Total Hazardous Air Pollutants (HAPs)	13	5.7	23.8	16.5
Individual HAPs Listed Below:				

14. 4-Digit Facility Identification Code:

SIC Code: 4911	SIC Description: Electric Services
NAICS Code: 221112	NAICS Description: Electric power generation, fossil fuel (e.g., coal, oil, gas)

15. Description of general production process and operation for which a permit is being requested. If necessary, attach additional sheets to give an adequate description. Include layout drawings, as necessary, to describe each process. References should be made to source codes used in the application.

Application is for the construction of a nominal net 668-MW combined cycle power generation facility consisting of two natural gas-fired combustion turbines (CTs) and associated heat recovery steam generators (HRSGs) including duct burners, one steam turbine, one fuel heater, one auxiliary boiler, one 10-cell mechanical draft cooling tower, one 6-cell mechanical draft cooling tower, and one fuel oil storage tank.

See PSD Report in Attachment A for additional information.

16. Additional information provided in attachments as listed below:

- Attachment A - PSD Report
- Attachment B - Acid Rain Forms
- Attachment C - Certification of Representation
- Attachment D -
- Attachment E -
- Attachment F -

17. Additional Information: Unless previously submitted, include the following two items:

- ☒ Plot plan/map of facility location or date of previous submittal: see PSD Report
- ☒ Flow Diagram or date of previous submittal: see PSD Report

Facility Name: Effingham County Power Plant

Date of Application: June 11, 2010

FORM 2.00 – EMISSION UNIT LIST

Emission Unit ID	Name	Manufacturer and Model Number	Description
CTG3	Combustion Turbine Unit 3	GE 7FA CT	Natural gas-fired nominal 180-MW combustion turbine
CTG4	Combustion Turbine Unit 4	GE 7FA CT	Natural gas-fired nominal 180-MW combustion turbine
DB3	Duct Burner Unit 3	to be decided	470 MMBtu/hr (HHV) duct burner
DB4	Duct Burner Unit 4	to be decided	470 MMBtu/hr (HHV) duct burner
FP2	Fuel Heater Unit 2	to be decided	8.75 MMBtu/hr natural gas-fired fuel heater
AB2	Auxiliary Boiler Unit 2	to be decided	17.0 MMBtu/hr natural gas-fired boiler
CT3	Mechanical Draft Cooling Tower	to be decided	10-cell mechanical draft cooling tower
CT4	Inlet Chiller Cooling Tower	to be decided	6-cell inlet chiller cooling tower
T01	Fuel Oil Tank	to be decided	2,350,000 gal fuel oil tank (fixed roof)

Date of Application: June 11, 2010

[illegible]

(a) Based on 59 °F ambient temperature. See PSD Report in Attachment A.

Facility Name: Effingham County Power Plant

Date of Application: June 11, 2010

FUEL DATA

Emission Unit ID	Fuel Type	Potential Annual Consumption				Hourly Consumption		Heat Content		Percent Sulfur		Percent Ash in Solid Fuel	
		Total Quantity		Percent Use by Season		Max.	Avg.	Min.	Avg.	Max.	Avg.	Max.	Avg.
		Amount	Units	Ozone Season May 1 - Sept 30	Non-ozone Season Oct 1 - Apr 30								
CTG3	NG	16,644*	10 ⁶ scf	41.9	58.1	1.9 × 10 ⁶ scf	NA	23,864 Btu/lb	NA	0.5 gr/100 scf	NA	NA	NA
CTG3	Diesel	109.2*	10 ⁶ lbs	41.9	58.1	109,234 lbs	NA	19,093 Btu/lb	NA	0.0015%	NA	NA	NA
CTG4	NG	16,644*	10 ⁶ scf	41.9	58.1	1.9 × 10 ⁶ scf	NA	23,864 Btu/lb	NA	0.5 gr/100 scf	NA	NA	NA
CTG4	Diesel	109.2*	10 ⁶ lbs	41.9	58.1	109,234 lbs	NA	19,093 Btu/lb	NA	0.0015 %	NA	NA	NA
DB3	NG	1,790.5*	10 ⁶ scf	41.9	58.1	0.447 × 10 ⁶ scf	NA	23,864 Btu/lb	NA	0.5 gr/100 scf	NA	NA	NA
DB4	NG	1,790.5*	10 ⁶ scf	41.9	58.1	0.447 × 10 ⁶ scf	NA	23,864 Btu/lb	NA	0.5 gr/100 scf	NA	NA	NA
FP2	NG	73.00*	10 ⁶ scf	41.9	58.1	8,333 scf	NA	23,864 Btu/lb	NA	0.5 gr/100 scf	NA	NA	NA
AB2	NG	40.48*	10 ⁶ scf	41.9	58.1	16,190 scf	NA	23,864 Btu/lb	NA	0.5 gr/100 scf	NA	NA	NA

Fuel Supplier Information

Fuel Type	Name of Supplier	Phone Number	Supplier Location			
			Address	City	State	Zip
NG	Georgia Natural Gas					
Diesel	To be decided					

*Fuel consumption data based on maximum consumption potential at baseload and 20°F ambient temperature.

Facility Name:

Effingham County Power Plant

Date of Application:

June 11, 2010

Form 3.00 – AIR POLLUTION CONTROL DEVICES - PART A: GENERAL EQUIPMENT INFORMATION

[illegible]

Facility Name: Effingham County Power Plant

Date of Application: June 11, 2010

Form 3.00 – AIR POLLUTION CONTROL DEVICES – PART B: EMISSION INFORMATION

[illegible]

* Natural gas firing at baseload operation with duct firing at 59 °F.

Facility Name: Effingham County Power PlantDate of Application: June 11, 2010**FORM 4.00 – EMISSION INFORMATION**

Emission Unit ID	Air Pollution Control Device ID	Stack ID	Pollutant Emitted	Emission Rates				
				Hourly Actual Emissions (lb/hr)	Hourly Potential Emissions (lb/hr)	Actual Annual Emission (tpy)	Potential Annual Emission (tpy)	Method of Determination
Natural Gas Firing:								
CTG3 & DB3	SCR1	S007	NO _x	28.8	28.8	139.1	139.1	See Attachment A, PSD Report
CTG3 & DB3	NA	S007	CO	52.9	52.9	266.1	266.1	See Attachment A, PSD Report
CTG3 & DB3	NA	S007	VOC	6.2	6.2	22.7	22.7	See Attachment A, PSD Report
CTG3 & DB3	NA	S007	PM/PM ₁₀ /PM _{2.5}	13.6	13.6	54.1	54.1	See Attachment A, PSD Report
CTG3 & DB3	NA	S007	SO ₂	3.4	3.4	12.6	12.6	See Attachment A, PSD Report
CTG3 & DB3	NA	S007	SAM	0.6	0.6	2.3	2.3	See Attachment A, PSD Report
CTG3 & DB3	NA	S007	HAPS	1.02	1.02	5.4	5.4	See Attachment A, PSD Report
CTG4 & DB4	SCR2	S008	NO _x	28.8	28.8	139.1	139.1	See Attachment A, PSD Report
CTG4 & DB4	NA	S008	CO	52.9	52.9	266.1	266.1	See Attachment A, PSD Report
CTG4 & DB4	NA	S008	VOC	6.2	6.2	22.7	22.7	See Attachment A, PSD Report
CTG4 & DB4	NA	S008	PM/PM ₁₀ /PM _{2.5}	13.6	13.6	54.1	54.1	See Attachment A, PSD Report
CTG4 & DB4	NA	S008	SO ₂	3.4	3.4	12.6	12.6	See Attachment A, PSD Report
CTG4 & DB4	NA	S008	SAM	0.6	0.6	2.3	2.3	See Attachment A, PSD Report
CTG4 & DB4	NA	S008	HAPS	1.02	1.02	5.4	5.4	See Attachment A, PSD Report

Facility Name: Effingham County Power Plant Date of Application: June 11, 2010

FORM 4.00 – EMISSION INFORMATION

Emission Unit ID	Air Pollution Control Device ID	Stack ID	Pollutant Emitted	Emission Rates				
				Hourly Actual Emissions (lb/hr)	Hourly Potential Emissions (lb/hr)	Actual Annual Emission (tpy)	Potential Annual Emission (tpy)	Method of Determination
Fuel Oil Firing:								
CTG3 & DB3	SCR1	S007	NO _x	90.0	90.0	139.1	139.1	See Attachment A, PSD Report
CTG3 & DB3	NA	S007	CO	138.1	138.1	266.1	266.1	See Attachment A, PSD Report
CTG3 & DB3	NA	S007	VOC	12.5	12.5	22.7	22.7	See Attachment A, PSD Report
CTG3 & DB3	NA	S007	PM/PM ₁₀ /PM _{2.5}	18.3	18.3	54.1	54.1	See Attachment A, PSD Report
CTG3 & DB3	NA	S007	SO ₂	3.9	3.9	12.6	12.6	See Attachment A, PSD Report
CTG3 & DB3	NA	S007	SAM	0.7	0.7	2.3	2.3	See Attachment A, PSD Report
CTG3 & DB3	NA	S007	HAPS	2.4	2.4	5.4	5.4	See Attachment A, PSD Report
CTG4 & DB4	SCR2	S008	NO _x	90.0	90.0	139.1	139.1	See Attachment A, PSD Report
CTG4 & DB4	NA	S008	CO	138.1	138.1	266.1	266.1	See Attachment A, PSD Report
CTG4 & DB4	NA	S008	VOC	12.5	12.5	22.7	22.7	See Attachment A, PSD Report
CTG4 & DB4	NA	S008	PM/PM ₁₀ /PM _{2.5}	18.3	18.3	54.1	54.1	See Attachment A, PSD Report
CTG4 & DB4	NA	S008	SO ₂	3.9	3.9	12.6	12.6	See Attachment A, PSD Report
CTG4 & DB4	NA	S008	SAM	0.7	0.7	2.3	2.3	See Attachment A, PSD Report
CTG4 & DB4	NA	S008	HAPS	2.4	2.4	5.4	5.4	See Attachment A, PSD Report

Facility Name: Effingham County Power PlantDate of Application: June 11, 2010**FORM 4.00 – EMISSION INFORMATION**

Emission Unit ID	Air Pollution Control Device ID	Stack ID	Pollutant Emitted	Emission Rates				
				Hourly Actual Emissions (lb/hr)	Hourly Potential Emissions (lb/hr)	Actual Annual Emission (tpy)	Potential Annual Emission (tpy)	Method of Determination
FGH2	NA	S009	NO _x	0.44	0.44	1.92	1.92	See Attachment A, PSD Report
FGH2	NA	S009	CO	0.72	0.72	3.14	3.14	See Attachment A, PSD Report
FGH2	NA	S009	VOC	0.05	0.05	0.20	0.20	See Attachment A, PSD Report
FGH2	NA	S009	PM/PM ₁₀ /PM _{2.5}	0.06	0.06	0.28	0.28	See Attachment A, PSD Report
FGH2	NA	S009	SO ₂	0.012	0.012	0.052	0.052	See Attachment A, PSD Report
AB2	NA	S010	NO _x	1.67	1.67	2.08	2.08	See Attachment A, PSD Report
AB2	NA	S010	CO	1.39	1.39	1.74	1.74	See Attachment A, PSD Report
AB2	NA	S010	VOC	0.09	0.09	0.11	0.11	See Attachment A, PSD Report
AB2	NA	S010	PM/PM ₁₀ /PM _{2.5}	0.12	0.12	0.15	0.15	See Attachment A, PSD Report
AB2	NA	S010	SO ₂	0.023	0.023	0.029	0.029	See Attachment A, PSD Report
CT3	NA	S011A-S011J	PM	0.78	0.78	3.4	3.4	See Attachment A, PSD Report
CT3	NA	S011A-S011J	PM ₁₀	0.59	0.59	2.58	2.58	See Attachment A, PSD Report
CT3	NA	S011A-S011J	PM _{2.5}	0.002	0.002	0.01	0.01	See Attachment A, PSD Report

Facility Name: Effingham County Power Plant

Date of Application: June 11, 2010

FORM 4.00 – EMISSION INFORMATION

Emission Unit ID	Air Pollution Control Device ID	Stack ID	Pollutant Emitted	Emission Rates				
				Hourly Actual Emissions (lb/hr)	Hourly Potential Emissions (lb/hr)	Actual Annual Emission (tpy)	Potential Annual Emission (tpy)	Method of Determination
CT4	NA	S012A-S012F	PM	0.05	0.05	0.22	0.22	See Attachment A, PSD Report
CT4	NA	S012A-S012F	PM ₁₀	0.04	0.04	0.17	0.17	See Attachment A, PSD Report
CT4	NA	S012A-S012F	PM _{2.5}	0.0001	0.0001	0.0007	0.0007	See Attachment A, PSD Report
T01 ²	NA	NA	VOC	0.11	0.11	0.49	0.49	See Attachment A, PSD Report

Notes:

1. Hourly emissions are worst-case emissions shown in Tables 2-1 and 2-2 of the PSD report. Annual emissions are based on 59°F ambient temperature and are shown in Table 2-3.
2. For CTG3 & DB3 and CTG4 & DB4, potential annual emissions represent natural gas and fuel oil combined firing and includes startup and shutdown.

Facility Name: Effingham County Power Plant
Date of Application: June 11, 2010

FORM 5.00 MONITORING INFORMATION

Emission Unit ID/ APCD ID	Emission Unit/APCD Name	Monitored Parameter		Monitoring Frequency
		Parameter	Units	
CTG3 & DB3	Combustion Turbine & Duct Burner Unit 1	NO _x	ppm	Continuous
CTG3 & DB3	Combustion Turbine & Duct Burner Unit 1	CO	ppm	Continuous
CTG4 & DB4	Combustion Turbine & Duct Burner Unit 2	NO _x	ppm	Continuous
CTG4 & DB4	Combustion Turbine & Duct Burner Unit 2	CO	ppm	Continuous

Comments:

Facility Name: Effingham County Power PlantDate of Application: June 11, 2010**FORM 7.00 – AIR MODELING INFORMATION: Stack Data**

Stack ID	Emission Unit ID(s)	Stack Information			Dimensions of largest Structure Near Stack		Exit Gas Conditions at Maximum Emission Rate			
		Height Above Grade (ft)	Inside Diameter (ft)	Exhaust Direction	Height (ft)	Longest Side (ft)	Velocity (ft/sec)	Temperature (°F)	Flow Rate (acfm)	
									Average	Maximum
S007	CTG3 & DB3	165	19.0	Toward the Sky	90	71.2	61.3	202.0	1,043,661	1,043,661
S008	CTG4 & DB4	165	19.0	Toward the Sky	90	71.2	61.3	202.0	1,043,661	1,043,661
S009	FP2	19.2	2.6	Toward the Sky	—	—	5.51	825	1,755	1,755
S010	AB2	39.1	2.6	Toward the Sky	—	—	18.1	476	5,762	5,762
S011A-S011J	CT3	43	33	Toward the Sky	—	—	1,877	99	1,605,357	1,605,357
S012A-S012F	CT4	42	21.4	Toward the Sky	—	—	482	99	173,344	173,344

NOTE: If emissions are not vented through a stack, describe point of discharge below and, if necessary, include an attachment. List the attachment in Form 1.00 *General Information*, Item 16.

Exhaust gas conditions for S001 and S002 are based on natural gas fired baseload operation at 59°F with duct-firing. See PSD Report.

Facility Name: Effingham County Power Plant **Date of Application:** June 11, 2010

FORM 7.00 AIR MODELING INFORMATION: Chemicals Data

[illegible]

ATTACHMENT A
PSD REPORT

1.0 INTRODUCTION AND EXECUTIVE SUMMARY

1.1 Introduction

Mackinaw Power is proposing to expand the power generation capacity of the existing Effingham Power Plant in Effingham County, Georgia, by constructing and operating a second 2x1 combined cycle power island with a nominal net electrical output of 668 megawatts (MW) (Figures 1-1 and 1-2). The project is referred to as the Effingham Power Expansion Project (the “Project”). The existing Effingham Power Plant is located on McCall Road approximately 5 kilometers (km) west of Rincon, Georgia.

The Project will have a “2-on-1” combined cycle configuration and will consist of:

- Two nominal 180-MW GE Model 7FA combustion turbines (CTs) that will operate in combined cycle mode fired primarily by natural gas with ultra low-sulfur diesel (ULSD) fuel as a backup fuel
- Two heat recovery steam generators (HRSGs) each equipped with a duct burner together with selective catalytic reduction (SCR) for control of nitrogen oxides (NO_x). The CT units will also have dry low-NO_x (DLN) burners
- One steam turbine generator (STG) (approximately 325 MW)
- One auxiliary boiler
- A fuel gas heater
- A 10-cell mechanical draft cooling tower
- A 6-cell mechanical draft cooling tower for inlet chiller systems
- A fuel oil storage tank
- Associated equipment

1.2 New Source Review Requirements

Under the New Source Review (NSR) regulations, an area is designated as attainment or unclassified if the air quality in the area meets the National Ambient Air Quality Standards (NAAQS). Effingham County has been designated as an attainment or unclassifiable area for sulfur dioxide (SO₂), particulate matter (PM), particulate matter less than 10 micrometers (µm) in diameter (PM₁₀), particulate matter less than 2.5 µm in diameter (PM_{2.5}), nitrogen dioxide (NO₂), carbon monoxide (CO), and lead. An attainment area is again classified into three classes depending on the amount or “increment” of additional air pollution allowed in each area – Class I, Class II, and Class III. All areas of Effingham County are classified as Class II, where moderate deterioration is permitted.

Prevention of Significant Deterioration (PSD) regulations are promulgated under Title 40, Part 52.21 of the Code of Federal Regulations (40 CFR 52.21) and implemented through delegation to the Georgia Department of Natural Resources, Environmental Protection Division (Georgia EPD). Georgia EPD has adopted by reference EPA PSD regulations [Chapter 391-3-1-.02 (7)].

The permitting of the Project requires an air construction permit and PSD review and approval. The existing Effingham Plant is currently a major source of criteria air pollutants. The Project will be a modification of a major source of air emissions. The PSD regulations require a PSD review for new or modified sources that increase air emissions above certain threshold amounts. Because certain threshold amounts will be exceeded by the Project, the Project is subject to PSD review.

The total potential emissions in tons per year (TPY) associated with this Project are presented in Table 1-1. Based on the emissions from the proposed Project, a PSD review is required for each of the following regulated pollutants:

- Particulate matter with aerodynamic diameter of 10 microns or less (PM₁₀)
- Fine particulate matter (PM_{2.5})
- Nitrogen dioxide (NO₂)
- Carbon monoxide (CO)
- Volatile organic compounds [VOCs (for ozone)]

Based on the PSD requirements, the Project is required to undergo the following analyses related to PSD for each pollutant emitted in significant amounts:

- Control technology review
- Source impact analysis
- Air quality analysis (monitoring)
- Source information
- Additional impact analyses

Best available control technology (BACT) analyses were conducted for each pollutant with emissions greater than the U.S. Environmental Protection Agency (EPA) significance threshold. During natural gas firing, the proposed BACT to control NO_x emissions from the two CTs operating in combined cycle mode is the use of DLN burners and SCR. The NO_x concentration will be limited to 2.5 parts per million (ppm), volume dry (ppmvd), corrected to 15-percent oxygen (O₂) when firing natural gas. During fuel oil firing, NO_x emissions will be controlled by water injection and SCR (using aqueous ammonia) and limited to 10 ppmvd, corrected to 15-percent O₂. Duct burners using only natural gas may be fired when the CTs are firing natural gas or fuel oil.

The proposed BACT for PM₁₀ and PM_{2.5} are good combustion practices utilizing the DLN combustor and firing natural gas fuel and ultra low-sulfur fuel oil. The proposed BACT for CO and VOC is also good combustion practices.

Fuel oil firing in the CTs will be limited to 1,000 hours per year (hr/yr) per unit.

1.3 Summary of Results

Results from the analyses presented in this PSD air permit application lead to the following conclusions:

- The proposed BACT for each applicable pollutant provides the maximum degree of emissions reduction that is achievable when energy, environmental, and economic impacts and technical feasibility are considered.
- National and State Ambient Air Quality Standards (AAQS) will not be exceeded as a result of the operation of the Project.
- Applicable PSD increments will not be exceeded as a result of the operation of the Project.
- Non-criteria pollutants emitted from the Project will not adversely affect the public.
- Visibility impacts from the Project's plume on Class I and II areas are not anticipated to have a significant impairment to local visibility or regional haze.
- No effects are expected to soils and vegetation as a result of the operation of the Project.
- The operation of the Project is not expected to adversely affect population or economic growth in the area; thus, no additional secondary emissions or impacts are anticipated.

As substantiated in this application, the Project will be constructed and operated in compliance with all applicable state and federal rules, regulations, and laws.

1.4 Air Permit Application Organization

The air permit application is divided into seven major sections.

- Section 2.0 presents a description of the facility, including air emissions and stack parameters.
- Section 3.0 provides a review of the PSD requirements applicable to the proposed Project.
- Section 4.0 includes the control technology review with discussions on BACT.
- Section 5.0 discusses the ambient air monitoring analysis (pre-construction monitoring) required by PSD regulations.
- Section 6.0 presents a summary of the air modeling approach and results used in assessing the compliance of the proposed Project with AAQS, PSD increments, and good engineering practice (GEP) stack height regulations.
- Section 7.0 provides the additional impact analyses for soils, vegetation, and visibility.

2.0 PROJECT DESCRIPTION

2.1 Site Description

The Effingham Power Plant is located on McCall Road in Effingham County, Georgia, approximately 5 km west of Rincon and 28 km northwest of Savannah. The Project will be located adjacent to and northeast of the existing power block. The surroundings of the Effingham Plant are flat and rural with the site elevation approximately 75 feet above mean sea level (ft-msl).

2.2 Project Sources

The Project will add a second power block at the existing Effingham Power Plant, a mirror image of the existing power block, which will consist of two nominal 180-MW General Electric (GE) 7FAs that will operate in combined cycle mode, two HRSGs with two 470-million British thermal unit per hour (MMBtu/hr) high-heating value (HHV) duct burners (one per HRSG), one nominal 325-MW STG, and associated equipment. The total electric power capacity of the Project will be approximately 685 MW (nominal gross).

The Project will also consist of the auxiliary boiler, fuel gas heater, 10-cell mechanical draft cooling tower, 6-cell cooling tower, and a fuel oil storage tank.

2.2.1 Combined Cycle Units

A CT is an internal combustion engine that operates with rotary motion to drive an electric generator to produce electricity. CTs are essentially composed of three major components: compressor, combustor, and power turbine. In the compressor section, ambient air is drawn in, compressed and directed to the combustor section where fuel is introduced, ignited, and burned. The rotary power is achieved by the expansion of the combustion gases through the power turbine. For this Project, the combustion process is based on lean premix staged combustion. For lean premix combustors, fuel and air are thoroughly mixed in an initial stage resulting in a uniform, lean, unburned fuel/air mixture that is delivered to a secondary stage where the combustion reaction takes place. Manufacturers use different types of fuel/air staging, including fuel staging, air staging, or both; however, the same staged lean premix principle is applied. CTs using staged combustion are also referred to as DLN combustors.

Hot gases from the combustion section are diluted with additional air from the compressor section and directed to the power turbine section at very high temperatures. Energy from the hot exhaust gases, which expand in the power turbine section, is recovered in the form of shaft horsepower. More than 50 percent of the shaft horsepower is needed to drive the internal compressor, and the balance of recovered shaft horsepower is available to drive an external load. The heat content of the exhaust gases exiting the turbine can be exhausted to the atmosphere without heat recovery (referred to as simple cycle mode) or directed to a HRSG to produce steam for a steam turbine (referred to as combined cycle mode).

In combined cycle mode, the gas turbine drives an electric generator, and the steam from the HRSG drives a steam turbine, which also drives an electric generator.

The duct burners in the HRSGs may be fired to add further heat energy to the gas turbine exhaust gases flowing through the boilers, increasing the production of steam to be sent to the steam turbine. Each duct burner will have a maximum heat input rate of 470 MMBtu/hr (HHV) and will be fired by only natural gas. The duct burners will be used when the Project is operating at or near baseload conditions. For permitting purposes, the duct burners are assumed to operate for a maximum of 4,000 hr/yr.

The GE 7FA CTs will have an inlet chilling system at the turbine air inlet that reduces the inlet air temperature. Because cooled air is denser, cooling the turbine inlet air even by a few degrees can increase the mass flow substantially resulting in substantial increase in turbine power output and efficiency. The advantage of an inlet chiller system is that it can cool the inlet air regardless of ambient humidity and a broad range of cooling can be achieved. The drawback is that a source is needed for the chilled water. The Project will include a 6-cell cooling tower to provide chilled water.

Process flow diagrams of the facility operating at baseload in combined cycle mode at ambient temperatures of 20, 59, and 95 degrees Fahrenheit (°F) (with inlet chilling and duct firing) are presented in Figures 2-1 through 2-3, respectively.

The Project will be capable of continuous operation at baseload for up to 8,760 hr/yr at an annual capacity factor of 100 percent. However, the CTs typically will operate between 50 and 100 percent of load for an annual average capacity factor of approximately 40 to 60 percent. The economic incentive is to dispatch the Plant as near to 100-percent load whenever possible. The CTs may be operated individually or in combination. ULSD fuel with 0.0015-percent sulfur content (by weight) will be used as a backup fuel up to a maximum of 1,000 hr/yr per unit.

Natural gas will be transported to the site via pipeline and will be the primary fuel used for the CTs and the only fuel for the HRSG duct burners. ULSD fuel oil will be supplied via trucks and stored on-site in a storage tank.

Air emissions controls will consist of state-of-the-art DLN burners and SCR using aqueous ammonia for NO_x emissions control during natural gas-firing. The DLN combustors for the GE 7FA CTs have premixed fuel zones plus a standard diffusion flame pilot burner for flame stability. Low NO_x levels are achieved by introducing fuel primarily to the pre-mix zones to create a very uniform temperature in the combustion zone. This also reduces the amount of fuel being combusted from the pilot nozzle.

SCR and water injection will be used to control NO_x during fuel oil-firing. Water injection reduces NO_x emissions by reducing the temperature of the combustion chamber.

NO_x emission levels for natural gas and fuel oil firing will also be controlled with an SCR system that will reduce NO_x emissions from the CTs and duct burners to 2.5 ppmvd, corrected to 15 ppmvd at 15-percent O₂ for natural gas firing and to 10 ppmvd at 15-percent O₂ for fuel oil firing, both based on a 24-hour averaging period.

To provide the proper operating temperature range for the required conversion efficiency and system economy, the SCR will be located in the HRSG. The catalyst will be provided in modules, field installed into a structural steel reactor housing integral to the HRSG. Ammonia (NH₃) is carried by a diluent and injected into the exhaust gas upstream of the catalyst modules. NO_x emissions are reduced by a chemical reaction with the NH₃ in the presence of the catalyst.

The aqueous NH₃ handling system will include primary and standby diluent air blowers (each sized for 100-percent capacity), NH₃ flow control and measurement devices, an NH₃/air mixing chamber, distribution header(s), and an NH₃ injection grid (AIG). Overall control of the system will be handled by the distribution control system. The reactor housing will include an internal support structure for the catalyst modules, access manways and catalyst loading openings, and instrument connections for monitoring catalyst performance.

Good combustion practices and the use of natural gas as primary fuel and ultra low-sulfur fuel oil as backup fuel will minimize potential emissions of PM₁₀, PM_{2.5}, and other pollutants (e.g., trace metals). Good combustion practices will be utilized to reduce CO and VOC emissions. Because of the pipeline-quality natural gas and ULSD fuel, the SO₂ and sulfuric acid mist (SAM) emissions from the CTs will be very minimal. Sulfur content of natural gas will be limited to 0.5 grain per 100 standard cubic feet (scf).

2.2.2 Auxiliary Boiler

The Project will also have an auxiliary boiler with a maximum heat input rating of 17 MMBtu/hr. The auxiliary boiler will supply steam during startup sequences and will operate for a maximum 2,500 hr/yr. The auxiliary boiler will be fired by natural gas only and use low-NO_x burners (LNBs) in tandem with flue gas recirculation (FGR). The auxiliary boiler is used to provide high-temperature steam during periods when the combined cycle generating units are offline to accommodate more rapid combined cycle startup following shutdowns. The auxiliary boiler will not operate once the combined cycle unit achieves steady-state operations.

2.2.3 Fuel Gas Heater

The Project will have one fuel gas heater, with a maximum heat input rate of 8.75 MMBtu/hr. The heater will be fired by natural gas. The fuel gas heater is required to ensure that the natural gas supplied to the CTs meets the condition specifications of the gas turbine manufacturer.

2.2.4 Cooling Towers

The Project will have one cooling tower comprising 10 cells. The cooling tower will be used to provide cool water to the condensing steam turbine. A separate 6-cell cooling tower will be used for the inlet chiller system. The towers will be mechanical draft counter flow design and will be equipped with high-efficiency drift eliminators. Drift eliminators use inertial separation caused by airflow direction changes to remove water droplets from the airstream exhausting from the cooling tower. Drift rate from the towers will be limited to 0.001 percent.

2.2.5 Fuel Oil Storage Tank

The ULSD fuel for the CTs will be stored in a fixed-roof fuel oil storage tank with a nominal capacity of 2,350,000 gallons. This is equivalent to about 3.5 days of storage with both CTs operating at full load.

2.3 Project Emissions and Stack Parameters

2.3.1 Combined Cycle Units

The Project CTs will operate only in combined cycle mode and will typically operate from 50 to 100 percent of their full load capacity. At CT operating loads below 100 percent, the mass emissions of all criteria pollutants decrease as load decreases to approximately 50 percent of full load.

The estimated maximum hourly emissions and exhaust information representative of the proposed GE 7FA CT burning natural gas and operating at 100-, 75-, and 50-percent load conditions for combined cycle mode are presented in Table 2-1. Estimated maximum emissions and stack conditions for fuel oil firing are presented in Table 2-2. The information in Table 2-1 is presented for one CT unit operation based on natural gas combustion for air inlet ambient temperatures of 20, 59, and 95°F. The same information is provided in Table 2-2 but for fuel oil firing. These temperatures represent the range of ambient temperatures that the CTs are most likely to experience. As shown, hourly emissions are highest at 20°F. Although the annual average temperature for the Project site is about 67°F, annual emissions are estimated assuming an ambient temperature of 59°F, which represents conservatively higher annual emissions.

The data in the tables were derived from other GE 7FA CTs from recent similar projects and data provided by Mackinaw Power, which are based on the existing GE 7FA CTs at the Effingham Power Plant. Since inlet chillers will be used only at high ambient temperatures, stack and operating parameters for the inlet chiller case were assumed equal to the 59°F case. When the inlet chillers are operating, the CTs generate more mass emissions of pollutants than when the chillers are not operating, because the mass flow of air passed through the volumetrically limited machines is increased. To provide a conservative estimate of maximum pollutant emissions, the maximum emissions assume that the inlet chillers would be used when the ambient temperature is 95°F.

The estimated maximum hourly emissions and exhaust information when the duct burner is fired are also presented in Tables 2-1 and 2-2. These maximum hourly emissions are based on a duct burner with a maximum heat input rate of 470 MMBtu/hr (HHV).

Table 2-3 presents emissions and exhaust parameters during startups and shutdowns (SU/SD). Emissions for certain pollutants such as NO_x, CO, and VOCs are higher during SU/SD than operations at normal operating conditions primarily due to lower combustion efficiency at lower loads. Higher SU/SD emissions are also due to the fact that the efficiency of the emissions control devices such as SCR is dependent on temperature, and until an optimum temperature is reached, the control device is not fully functional.

Emissions estimates for NO_x, CO, and VOCs during the SU/SD events were developed based on emissions data collected during the SU/SD events of the existing GE 7FA CTs at the Effingham Plant. SU/SD emissions are based on natural gas firing only. Two types of startups are considered – cold and warm. Each cold startup will take about 5 hours and each warm startup will take about 2.5 hours for the CTs to reach baseload. The duration of the typical shutdown event is approximately 1 hour. A total of 300 SU/SD events are considered for the year, which includes 290 warm startups and 10 cold startups. The 300 shutdowns have been included in the emissions calculation.

Each type of startup is preceded by engine downtime – at least 48 hours downtime before a cold start and between 2 to 48 hours downtime before a warm start. As shown in Table 2-4, different operating scenarios are analyzed with the maximum CT-only operating hours (8,760 hours) adjusted downward to account for SU/SD operating hours; 4,000 hours of duct firing; 1,000 hours of fuel oil firing; and an estimate of the amount of downtime between shutdown and startups, which is assumed to be a total of 1,060 hr/yr.

Excess emissions resulting from SU/SD and malfunction will be minimized by following best operational practices, operating air pollution control equipment in a manner consistent with good air pollution control practices, and minimizing the duration of excess emissions. These procedures are consistent with the procedures in Georgia EPD rules for excess emissions [Chapter 391-3-1-.02(a)7].

The maximum potential annual emissions for the CTs are presented in Table 2-4. The potential annual emissions are based on the 59°F ambient air condition since it represents a nominal average between the higher emission levels at the 20°F ambient condition (winter) and the 95°F ambient condition (summer). It also represents the temperature referenced in the new source performance standards (NSPS) for stationary combustion turbines (40 CFR Part 60, Subpart KKKK). The maximum emissions are presented for several operating scenarios that include the CTs operating at 100 percent with duct firing up to 4,000 hr/yr, fuel oil firing for up to 1,000 hr/yr, 300 SU/SD events, and downtime for up to 1,060 hr/yr.

2.3.2 Other Project Emissions

The Project will have two mechanical draft cooling towers (one 10-cell and one 6-cell). PM in the form of drift will result from the operation of the towers. The towers will be equipped with high-efficiency drift eliminators that will reduce drift to 0.001 percent of the circulating water flow rate. Since the drift will contain dissolved solids, PM will be formed when the drift aerosols evaporate in the atmosphere. Maximum total dissolved solids (TDS) content of the water is 1,000 ppm by weight. Table 2-5 presents information on the cooling tower and the potential PM, PM₁₀, and PM_{2.5} emissions from the drift.

The emission estimates for the natural gas fuel heater and the auxiliary boiler are presented in Tables 2-6 and 2-7, respectively. Annual operation of the auxiliary boiler will be limited to 2,500 hr/yr. The VOC emissions from the fuel oil storage tank will be less than 0.5 TPY (see Appendix A).

2.3.3 Maximum Project Annual Emissions

The overall potential annual emissions for the Project including the CTs, cooling towers, fuel gas heater, auxiliary boiler, and fuel oil storage tank are presented in Table 2-8.

Estimates of hazardous air pollutants (HAPs) emissions for the Project are presented in Table 2-9, which shows total annual HAP emissions and maximum individual HAP emissions. Emissions were estimated based on the following references:

- EPA's Compilation of Air Pollutant Emission Factors, also known as AP-42; Chapter 1.4, Natural Gas Combustion; and Chapter 3.1 Stationary Gas Turbines
- AB 2588 Combustion Emission Factors, Ventura County Air Pollution Control District, Ventura, CA, 2001

As shown in Table 2-8, the maximum total emissions of HAPs are estimated to be 10.8 TPY with maximum emissions of any single HAP at 3.6 TPY (i.e., for formaldehyde). The existing Effingham Power Plant is currently not a major source of HAPs, and the Project will not cause it to become a major source of HAPs. Therefore, the requirements of 40 CFR 63.43 for a maximum achievable control technology are not applicable to the Project.

Details of criteria pollutant and HAP emissions calculations are presented in Appendix A.

2.4 Site Layout, Structures, and Stack Sampling Facilities

A plot plan of the proposed facility is presented in Figure 2-4. The dimensions of the buildings and structures are presented in Section 6.0. Stack sampling facilities will be constructed in accordance to Georgia Rules for Air Quality Control, Chapter 391-3-1-.02(3), Sampling. Profiles of a CT and HRSG are presented in Figure 2-5.

The plot plan shows the existing facility property lines, major process equipment and structures, and all emission points. The entrance to the site has security gates to control site access. The fenced property boundary is shown in the figure.

3.0 AIR QUALITY REVIEW REQUIREMENTS AND APPLICABILITY

Federal and state air regulatory requirements for a new or modified source of air pollution are discussed in Sections 3.1 through 3.4. The applicability of these regulations to the proposed Project is presented in Section 3.5.

3.1 National and State Ambient Air Quality Standards

The existing applicable National and Georgia AAQS are presented in Table 3-1. Primary NAAQS were promulgated to protect the public health and secondary NAAQS were promulgated to protect the public welfare from any known or anticipated adverse effects associated with the presence of pollutants in the ambient air. Areas of the country in violation of NAAQS are designated as nonattainment areas, and new or modified sources located in or near these areas may be subject to more stringent air permitting requirements.

3.2 PSD Requirements

3.2.1 General Requirements

Under federal and State of Georgia 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. Georgia's State Implementation Plan (SIP), which contains PSD regulations, has been approved by the EPA. Therefore, PSD approval authority has been granted to Georgia EPD.

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 the CAA. "Potential to emit" means the capability, at maximum design capacity, to emit a pollutant after the application of control equipment. Once a new source or a modification is determined to be a "major" for a particular pollutant, any pollutant emitted in amounts greater than the PSD significant emission rates is subject to PSD review. The PSD significant emission rates are presented in Table 3-2.

EPA regulations identify certain increases above an air quality baseline concentration level of SO₂, PM₁₀, and NO₂ concentrations that would constitute significant deterioration. The EPA Class designations and allowable PSD increments are presented in Table 3-1. The magnitude of the allowable increment depends on the classification of the area in which a new source (or modification) will be located or have an impact. Two classifications are designated based on criteria established in the CAA Amendments. Congress authorized EPA to classify areas as Class I (international parks, national wilderness areas, and memorial parks larger than 5,000 acres and national parks larger than 6,000 acres) or as Class II (all areas not designated as Class I). No Class III areas, which would be allowed greater deterioration than Class II areas, were designated. The State of Georgia has adopted the EPA Class designations and allowable PSD increments for SO₂, PM₁₀, and NO₂ increments.

PSD review is used to determine whether significant air quality deterioration will result from the new or modified facility. Federal PSD requirements are contained in 40 CFR 52.21, Prevention of Significant Deterioration of Air Quality. The Georgia EPD has adopted by reference EPA PSD regulations in Chapter 391-3-1-.02(7). Major facilities or major modifications to an existing major facility are required to undergo the following analyses related to PSD for each pollutant emitted in significant amounts:

- Control technology review
- Source impact analysis
- Air quality analysis (monitoring)
- Source information
- Additional impact analyses

In addition to these analyses, a new facility or major modification also must be reviewed with respect to GEP stack height regulations. Discussions concerning each of these requirements are presented in the following sections.

3.2.2 Control Technology Review

The control technology review requirements of the federal and state PSD regulations require that all applicable federal and state emissions-limiting standards be met and that BACT be applied to control emissions from the source. The BACT requirements are applicable to all regulated pollutants for which the increase in emissions from the facility exceeds the respective significant emission rate (see Table 3-2).

BACT is defined in 40 CFR 52.21(b)(12) as:

An emissions limitation (including a visible emission standard) based on the maximum degree of reduction of each pollutant subject to regulation under the Act which would be emitted by any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts, and other costs, determination is achievable through application of production processes and available methods, systems, and techniques) for control of such pollutant. In no event shall application of best available control technology (BACT) result in emissions of any pollutant, which would exceed the emissions allowed by any applicable standard under 40 CFR Parts 60 and 61. If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular part of a source or facility would make the imposition of an emission standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of BACT. Such standard shall, to the degree possible, set forth the emissions reductions achievable by implementation of such design, equipment, work practice, or operation and shall provide for compliance by means, which achieve equivalent results.

BACT was promulgated within the framework of the PSD requirements in the 1977 amendments of the CAA [Public Law 95-95; Part C, Section 165(a)(4)]. The primary purpose of BACT is to optimize consumption of PSD air quality increments and thereby enlarge the potential for future economic growth

without significantly degrading air quality (EPA; 1978, 1980). Guidelines for the evaluation of BACT can be found in EPA's *Guidelines for Determining Best Available Control Technology (BACT)* (EPA, 1978), in the *PSD Workshop Manual-Draft* (EPA, 1980), and in the *New Source Review Workshop Manual-Draft* (EPA, 1990). These guidelines were promulgated by the EPA to provide a consistent approach to BACT and to ensure that the impacts of alternative emission control systems are measured by the same set of parameters. In addition, through implementation of these guidelines, BACT analyses must be conducted on a case-by-case basis, and BACT in one area may differ from BACT in another area. According to the EPA (1980), "BACT analyses for the same types of emissions unit and the same pollutants in different locations or situations may determine that different control strategies should be applied to the different sites, depending on site-specific factors. Therefore, BACT analyses must be conducted on a case-by-case basis."

BACT requirements are intended to ensure that the control systems incorporated in the design of a facility reflect the latest in control technologies used in a particular industry and take into consideration existing and future air quality in the vicinity of the proposed facility. BACT cannot be less stringent than any applicable NSPS for a source. An evaluation of the air pollution control techniques and systems is required, including a cost-benefit analysis of alternative control technologies capable of achieving a higher degree of emission reduction than the proposed control technology. The cost-benefit analysis requires the documentation of the material, energy, and economic penalties associated with the proposed and alternative control systems, as well as the environmental benefits derived from these systems. A decision on BACT is to be based on sound judgment, balancing environmental benefits with energy, economic, and other impacts (EPA, 1978).

The EPA has issued a draft guidance document on the top-down approach entitled, *Top-Down Best Available Control Technology Guidance Document* (EPA, 1990). EPA's BACT guidelines include a "top-down" approach to determine the "best available control technology" for application at a particular facility. These guidelines discuss the BACT as a "case-by-case" analysis to identify the most stringent emission control technologies that have been applied to the same or similar source categories, and then to select a BACT emission rate, taking into account technical feasibility and energy, environmental, and economic impacts specific to the project. The most effective control alternative not rejected from the analysis is proposed as BACT.

EPA's BACT guidelines establish a specific five-step analytical process for conducting a BACT determination. The five steps consist of:

1. Identifying the potentially applicable control technologies for the proposed process or source
2. Evaluating the technical options for feasibility taking into consideration source-specific factors
3. Comparing the remaining control technologies based on effectiveness

4. Evaluating the remaining options taking into consideration energy, environmental and economic impacts
5. Selecting BACT based on the above analyses

3.2.3 Source Impact Analysis

A source impact analysis must be performed for a proposed major source or major modification subject to PSD review, and for each pollutant for which the increase in emissions exceeds the PSD significant emission rate (see Table 3-2). PSD regulations specifically provide for the use of atmospheric dispersion models in performing impact analyses, estimating baselines and future air quality levels, and determining compliance with AAQS and allowable PSD increments. Models designated by the EPA must normally be used in performing the impact analysis. Specific applications for other than EPA-approved models require EPA's consultation and prior approval. Guidance for the use and application of dispersion models is presented in EPA's publication *Guideline on Air Quality Models* (Appendix W to 40 CFR Part 51, Federal Register dated November 9, 2005).

To address compliance with AAQS and PSD Class II increments, a source impact analysis must be performed for the criteria pollutants. However, this analysis is not required for a specific pollutant if the net increase in impacts as a result of the new source or modification is below significant impact levels, as presented in Table 3-1. The significant impact levels are threshold levels that are used to determine the level of air impact analyses needed for the project. If the new or modified source's impacts are predicted to be less than significant, then the source's impacts will not have a significant adverse affect on air quality, and additional modeling with other sources is not required. However, if the source's impacts are predicted to be greater than the significant impact levels, additional modeling with other sources is required to demonstrate compliance with AAQS and PSD increments.

For PM_{2.5}, EPA has proposed that one of three options could be significant impact levels (SILs) for the 24-hour and annual average, but does not presume that the levels are appropriate and recognizes that states could adopt different interim levels with appropriate records. Because SILs for the 1-hour NO₂ and SO₂ concentrations have not been proposed yet, states can provide interim levels until EPA promulgates the SILs for these pollutants. The presumed SILs for this project are discussed in Section 6.2.

The EPA has proposed significant impact levels for Class I areas as follows (also presented in Table 3-1):

- SO₂
 - 3-hour - 1 microgram per cubic meter (µg/m³)
 - 24-hour - 0.2 µg/m³
 - Annual - 0.1 µg/m³
- PM₁₀
 - 24-hour - 0.3 µg/m³
 - Annual - 0.2 µg/m³
- NO₂
 - Annual - 0.1 µg/m³

Although these levels have not been officially promulgated as part of the PSD review process and may not be binding for states in performing PSD reviews, the proposed levels serve as a guideline in assessing a source's impact in a Class I area. EPA's action to incorporate Class I significant impact levels in the PSD process is part of implementing the NSR provisions of the 1990 CAA Amendments. Because the process of developing the regulations will be lengthy, the EPA believes that the proposed rules concerning the significant impact levels are appropriate to assist states in implementing the PSD permitting process. The Georgia EPD has accepted the use of these significant impact levels. Source impact analyses for PSD Class I areas are performed if the source is within 200 km of the Class I area.

Various lengths of record for meteorological data can be used for impact analysis. A 5-year period is normally used with corresponding evaluation of highest, second-highest (HSH) short-term concentrations for comparison to AAQS or PSD increments. The meteorological data are selected based on an evaluation of measured weather data from a nearby weather station that represents weather conditions at the project site. The criteria used in this evaluation include determining the distance of the project site to the weather station, comparing topographical and land use features between the locations, and determining availability of necessary weather parameters. The selection of the weather data for the Project was proposed in a modeling protocol submitted to Georgia EPD and approved by them prior to initiating air modeling.

The term "HSH" refers to the highest of the second-highest concentrations at each receptor for each year (i.e., the highest concentration at each receptor is discarded, and the highest of the remaining concentrations at each receptor is identified). The second-highest concentration is important because the short-term AAQS specify that the standard cannot be exceeded at any location more than once a year. If fewer than 5 years of meteorological data are used in the modeling analysis, the highest concentration at each receptor normally must be used for comparison to air quality standards.

Similarly, the term "H6H" refers to the highest of the sixth-highest concentrations at each receptor over 5 years (i.e., the six highest concentrations at each receptor for 5 years combined is identified, and the highest five concentrations at each receptor are discarded; the highest remaining concentration is used).

The term "baseline concentration" evolves from federal and state PSD regulations and refers to a concentration level corresponding to a specified baseline date and certain additional baseline sources.

By definition, in the PSD regulations as amended August 7, 1980, baseline concentration means the ambient concentration level that exists in the baseline area at the time of the applicable baseline date. A baseline concentration is determined for each pollutant for which a baseline date is established and includes:

1. The actual emissions representative of facilities in existence on the applicable date.
2. The allowable emissions of major stationary facilities that commenced before January 6, 1975, for SO₂ and PM₁₀ concentrations, or February 8, 1988, for NO₂ concentrations, but that were not in operation by the applicable baseline date.

The following emissions are not included in the baseline concentration and therefore affect PSD increment consumption:

1. Actual emissions from any major stationary facility on which construction commenced after January 6, 1975, for SO₂ and PM₁₀ concentrations, and after February 8, 1988, for NO₂ concentrations.
2. Actual emission increases and decreases at any stationary facility occurring after the baseline date.

In reference to the baseline concentration, the term “baseline date” actually includes three different dates:

1. The major facility baseline date, which is January 6, 1975, in the cases of SO₂ and PM₁₀, and February 8, 1988, in the case of NO₂.
2. The minor facility baseline date, which is the earliest date after the trigger date on which a major stationary facility or major modification subject to PSD regulations submits a complete PSD application.
3. The trigger date, which is August 7, 1977, for SO₂ and PM₁₀, and February 8, 1988, for NO₂.

The Georgia EPD has also adopted an air toxics policy. Air quality impacts for toxic air pollutants emitted by the Project will be assessed by the Georgia EPD procedures in *Guideline for Ambient Impact Assessment of Toxic Air Pollutant Emissions* (Revised June 21, 1998). This policy requires atmospheric dispersion modeling for all non-criteria pollutants for which a threshold limit value or unit risk factor has been developed. The Georgia EPD has established acceptable ambient concentration (AAC) levels that are annual and/or 24-hour average concentrations not to be exceeded by the proposed source.

3.2.4 Air Quality Monitoring Requirements

In accordance with requirements of 40 CFR 52.21(m), any application for a PSD permit must contain an analysis of continuous ambient air quality data in the area affected by the proposed major stationary facility or major modification. For a new major facility, the affected pollutants are those that the facility potentially would emit in significant amounts. For a major modification, the pollutants are those for which the net emissions increase exceeds the significant emission rate (refer to Tables 3-2 and 3-3).

Ambient air monitoring for a period of up to 1 year generally is appropriate to satisfy the PSD monitoring requirements. A minimum of 4 months of data are required. Existing data from the vicinity of the proposed source may be used if the data meet certain quality assurance requirements; otherwise, additional data may need to be gathered.

The regulations include an exemption that excludes or limits the pollutants for which an air quality analysis must be conducted. This exemption states that Georgia EPD may exempt a proposed major stationary facility or major modification from the monitoring requirements with respect to a particular pollutant if the emissions increase of the pollutant from the facility or modification would cause, in any area, air quality impacts less than the *de minimis* levels presented in Table 3-2.

3.2.5 Source Information/GEP Stack Height

Source information must be provided to adequately describe the proposed Project. The general type of information required for this Project is presented in Section 2.0.

The 1977 CAA Amendments require that the degree of emission limitation required for control of any pollutant not be affected by a stack height that exceeds GEP or any other dispersion technique. On July 8, 1985, EPA promulgated final stack height regulations (EPA, 1985a). The Georgia EPD [Chapter 391-3-1.02(7)(b)4] has adopted identical regulations. GEP stack height is defined as the highest of:

1. 65 meters; or
2. A height established by applying the formula:
$$H_g = H + 1.5L$$

where: H_g = GEP stack height,
 H = Height of the structure or nearby structure, and
 L = Lesser dimension (height or projected width) of nearby structure(s); or
3. A height demonstrated by a fluid model or field study.

“Nearby” is defined as a distance up to five times the lesser of the height or width dimensions of a structure or terrain feature, but not greater than 0.8 km. Although GEP stack height regulations require that the stack height used in modeling for determining compliance with AAQS and PSD increments not exceed the GEP stack height, the actual stack height may be greater.

The stack height regulations also allow increased GEP stack height beyond that resulting from the above formula in cases where plume impaction occurs. Plume impaction is defined as concentrations measured or predicted to occur when the plume interacts with elevated terrain. Elevated terrain is defined as terrain that exceeds the height calculated by the GEP stack height formula.

3.2.6 Additional Impact Analysis

In addition to air quality impact analyses, federal and Georgia PSD regulations require analyses of the impairment to visibility and the impacts on soils and vegetation that would occur as a result of the proposed source [40 CFR 52.21(o)]. These analyses are to be conducted primarily for PSD Class I areas. Impacts as a result of general commercial, residential, industrial, and other growth associated with

the source also must be addressed. These analyses are required for each pollutant emitted in significant amounts (see Table 3-2).

3.2.7 Air Quality Related Values

An air quality related values (AQRVs) analysis is required to assess the potential risk to AQRVs in PSD Class I areas. The Wolf Island National Wilderness Area (NWA) is the closest Class I area to Effingham Power Plant, and is located about 101 km (63 miles) from the Plant. The Okefenokee NWA is located about 162 km and the Cape Romain NWA is located about 167 km away from the Plant. No other Class I areas are located within 200 km from the Plant.

The U.S. Department of the Interior in 1978 administratively defined AQRVs to be:

All those values possessed by an area except those that are not affected by changes in air quality and include all those assets of an area whose vitality, significance, or integrity is dependent in some way upon the air environment. These values include visibility and those scenic, cultural, biological, and recreational resources of an area that are affected by air quality.

Important attributes of an area are those values or assets that make an area significant as a national monument, preserve, or primitive area. They are the assets that are to be preserved if the area is to achieve the purposes for which it was set aside (Federal Register, 1978).

AQRVs include visibility, freshwater and coastal wetlands, dominant plant communities, unique and rare plant communities, soils and associated periphyton, and the wildlife dependent on these communities for habitat. Rare, endemic, threatened, and endangered species of the national park and bioindicators of air pollution (e.g., lichens) must also be evaluated.

3.3 Nonattainment Rules

Based on the current nonattainment provisions [Chapter 391-3-1-.03(8)(c)], all major new facilities and modifications to existing major facilities located in a nonattainment area must undergo nonattainment review. A new major facility is required to undergo this review if the proposed pieces of equipment have the potential to emit 100 TPY or more of the nonattainment pollutant.

3.4 Emission Standards

3.4.1 New Source Performance Standards

The NSPS are a set of national emission standards that apply to specific categories of new sources. As stated in the CAA Amendments of 1977, 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 NSPS are contained in 40 CFR Part 60. The proposed Project will be subject to one or more NSPS.

3.4.1.1 Combustion Turbine and Duct Burner - Subpart KKKK

The applicable NSPS for the Combustion Turbines and duct burners is 40 CFR 60, Subpart KKKK, Standards of Performance for Stationary Combustion Turbines. The Subpart KKKK requirements supersede the 40 CFR 60, Subpart GG requirements for CTs that will commence construction after February 18, 2005 and apply to units with a maximum heat input capacity of 10 MMBtu/hr or greater. Subpart KKKK also applies to emissions from any associated HRSG and duct burners and supersedes the requirements of 40 CFR 60, Subparts Da, Db, and Dc. For natural gas-fired CTs greater than 850 MMBtu/hr heat input, NO_x emissions are limited to 15 ppm corrected to 15-percent O₂ or 0.43 pound per megawatt hour (lb/MW-hr). For CTs firing fuels other than natural gas with greater than 850 MMBtu/hr heat input, NO_x emissions are limited to 42 ppm corrected to 15-percent O₂ or 1.3 lb/MW-hr. For CTs located in the continental U.S., SO₂ emissions are limited to 0.90 lb/MW-hr gross output or 0.060 lb/MMBtu heat input.

In addition to emission limitations, the Project will be subject to the General Provisions in 40 CFR 60, Subpart A, including, but not limited to the following requirements for notification, record keeping, and performance testing:

40 CFR 60.7 – Notification and Record Keeping

- (a)(1) Notification of the date of construction - within 30 days after such date.
- (a)(3) Notification of actual date of initial startup - within 15 days after such date.
- (a)(5) Notification of date which demonstrates commencement of the continuous emissions monitoring (CEM) system – not less than 30 days prior to date.
- (b) Maintain records of the startup, shutdown, and malfunctions.
- (c) Excess emissions reports - by the 30th day following the end of the each six month period. (Required even if no excess emissions occur.)
- (f) Maintain a file of all measurements for 2 years.

40 CFR 60.8 – Performance Tests

- (a) Must be performed within 60 days after achieving maximum production rate, but no later than 180 days after initial startup.
- (b) Reference test methods shall be used unless use of alternative methods approved.
- (c) Emission limits shall not apply during periods of startup, shutdown, and malfunction.
- (d) Notification of performance tests at least 30 days prior to them occurring.

There are many other additional requirements within Subpart KKKK that apply to different types of CT operations. Below is a list of the requirements and exemptions that would specifically apply to the CT operations. These are in addition to the Subpart KKKK requirements applicable to all CT operations.

40 CFR 60.4340 – Monitoring for NO_x

- (b) How to demonstrate continuous compliance for NO_x if water or steam injection is not used – Owner or operator may install, calibrate, maintain and operate a continuous emission monitoring (CEM) as described in 40 CFR 60.4335(b) and 40 CFR 60.4345 to demonstrate continuous compliance.

40 CFR 60.4365 – Monitoring for SO₂

NSPS requires monitoring the fuel sulfur content. However, the owner or operator can be exempt from the sulfur content monitoring and may elect not to monitor the total sulfur content of the fuel combusted in the turbine, if the fuel is demonstrated not to exceed potential sulfur emissions of 0.06 lb SO₂/MMBtu heat input for units located in the continental U.S. The fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel can be provided that shows the maximum total sulfur content is 20 grains/100 scf or less.

40 CFR 60.4350 – Excess Emissions

- (h) For combined cycle and combined heat and power units with heat recovery, such as the Project's CTs, the calculated hourly average emission rates as described in 40 CFR 60.4350(f) are used to assess excess emissions on a 30 operating day rolling average basis. Excess emissions for NO_x are defined in 40 CFR 60.4380(b)(1). Excess emissions for SO₂ are defined in 40 CFR 60.4385(a).

40 CFR 60.4400 – Performance Tests for NO_x

- (a) Initial and subsequent performance tests for NO_x shall be conducted on an annual basis and no more than 14 calendar months following the previous performance test.

40 CFR 60.4415 – Performance Tests for SO₂

Initial and subsequent performance tests for SO₂ shall be conducted on an annual basis and no more than 14 calendar months following the previous performance test. Performance tests can be conducted by choosing to periodically determine the sulfur content of natural gas. ASTM Method D5287 is followed for collecting representative fuel samples of natural gas and ASTM Method D1072, or alternatively D3246, D4084, D4468, D4810, D6228, or D6667 can be used to analyze the samples. Alternately, a performance test can be conducted by measuring SO₂ concentration using EPA Methods 6, 6C, 8, or 20.

3.4.1.2 Fuel Heater and Auxiliary Boiler - Subpart Dc

The applicable NSPS for the fuel heater and the auxiliary boiler is 40 CFR Part 60, Subpart Dc, Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units. This subpart applies to a steam generating unit that has a maximum design heat input capacity of 100 MMBtu/hr (HHV) or less, but greater than or equal to 10 MMBtu/hr.

For natural gas-fired units, no pollutant emission limits are specified in the NSPS.

3.4.1.3 Fuel Oil Storage Tank - Subpart Kb

The applicable NSPS is 40 CFR Part 60, Subpart Kb--Standards of Performance for Volatile Organic Liquid Storage Vessels (including petroleum liquid storage vessels for which construction, reconstruction, or modification commenced after July 23, 1984). This subpart applies to each storage vessel with a capacity greater than or equal to 75 cubic meters (m^3) that is used to store volatile organic liquids (VOLs) for which construction, reconstruction, or modification is commenced after July 23, 1984.

However, this subpart does not apply to storage vessels with a capacity greater than or equal to 151 m^3 storing a liquid with a maximum true vapor pressure less than 3.5 kilopascals (kPa) or with a capacity greater than or equal to 75 m^3 but less than 151 m^3 storing a liquid with a maximum true vapor pressure less than 15.0 kPa.

3.4.2 Maximum Achievable Control Technology

The EPA has, and is currently developing, emissions standards for HAPs for various industrial categories. These new NESHAPs are based on the use of Maximum Achievable Control Technology (MACT). The adopted standards are contained in 40 CFR Part 63. Sources that emit more than 10 TPY of a single HAP or 25 TPY of total HAPs are required to apply MACT for the promulgated industrial category or to obtain a case-by-case MACT determined from the applicable regulatory authority after submitting a MACT analysis.

3.4.3 Clean Air Interstate Rule

The Clean Air Interstate Rule (CAIR) was promulgated under 40 CFR Part 96 to reduce the emissions of precursor pollutants to O_3 and fine particulate formation, and therefore the interstate transport of O_3 and fine particulates. CAIR applies to electric utility steam generating units. CAIR regulates NO_x and SO_2 emissions.

3.4.4 Georgia Rules

The Georgia EPD regulations for existing and new stationary sources are covered in Chapter 391 3-1-.02. The Georgia EPD has adopted the EPA NSPS by reference in Chapter 391-3-1-.02(8); Subsections (b)38 for stationary CTs and (b)3 for duct burners. Therefore, the Project must meet the same emissions, performance testing, monitoring, reporting, and record keeping requirements as those described in the EPA regulations. Georgia EPD has authority for implementing NSPS requirements in Georgia.

3.4.5 Georgia Air Permitting Requirements

The Georgia EPD regulations require any new source to obtain an air permit prior to construction. Major new sources must meet the appropriate PSD and nonattainment requirements as discussed previously. Required permits and approvals for air pollution sources include NSR for nonattainment areas, PSD, NSPS, National Emission Standards for Hazardous Air Pollutants (NESHAP), Permit to Construct,

and Permit to Operate. The requirements for construction permits and approvals are contained in Chapter 391-3-1-.03.

3.5 Source Applicability

3.5.1 Area Classification

The Project will be located in Effingham County, which has been designated by EPA and Georgia EPD as an attainment area for all criteria pollutants. Effingham County and surrounding counties are designated as PSD Class II areas for SO₂, PM₁₀, and NO₂. The nearest PSD Class I areas to the site are the Wolf Island NWA, Okefenokee NWA, and Cape Romain NWA located about 101, 162, and 167 km from the Effingham Power Plant, respectively. Other PSD Class I areas are located more than 200 km from the site.

Based on discussions with the Georgia EPD, the minor facility baseline date has been triggered in Effingham County. As a result, pollutant emissions from other PSD increment-consuming sources would need to be included in an air quality impact analysis if the Project's impacts are expected to be greater than the significant impact levels.

3.5.2 PSD Review

3.5.2.1 Pollutant Applicability

The existing Effingham Power Plant is a major source of air pollution. The proposed Project is considered to be a "major modification of a major facility" because the annual emissions of several regulated pollutants from the proposed Project are estimated to exceed EPA's significant emissions rate thresholds. Therefore, PSD review is required for any pollutant for which the emissions are considered major or exceed the significant emission rates. As shown in Table 3-3, potential emissions from the Project will be greater than the significant emission rate levels for NO_x, CO, VOCs, PM₁₀, and PM_{2.5}.

There are three Class I areas located within 200 km from the Effingham Plant. As a result, PSD Class I analyses were performed to determine if the Project's impacts would be less than the PSD Class I significant impact levels.

3.5.2.2 Emission Standards

The applicable NSPS for the CTs and duct burners is 40 CFR Part 60, Subpart KKKK. The proposed emissions for the CTs will be well below the specified limits (see Section 4.0). The applicable NSPS for the fuel heater and auxiliary boiler is 40 CFR Part 60, Subpart Dc. For natural gas-fired units, no pollutant emission limits are specified in the NSPS. Excess emissions from startup, shutdown, and malfunction will be minimized by following procedures in Georgia EPD rules for excess emissions [Chapter 391-3-1-.02(a)7]. These procedures include implementing best operational practices, operating

air pollution control equipment in a manner consistent with good air pollution control practice, and minimizing the duration of excess emissions.

The NSPS for Volatile Organic Liquid Storage Vessels is 40 CFR Part 60, Subpart Kb. The fuel oil storage tank will contain distillate fuel oil, a VOL as defined in Subpart Kb. However, since the true vapor pressure of distillate fuel oil is less than 3.5 kPa, this NSPS does not apply to the storage tank.

3.5.3 Ambient Monitoring Analysis

Based on the estimated pollutant emissions from the proposed Project (see Table 3-3), pre-construction ambient monitoring analyses for PM₁₀, PM_{2.5}, NO₂, CO, and ozone (O₃) (based on NO_x emissions) are required to be submitted as part of the application. However, if the net increase in impact of these pollutants is less than the applicable *de minimis* monitoring concentration (100 TPY of NO_x or VOC in the case of O₃), then an exemption from submittal of pre-construction ambient monitoring data may be obtained [40 CFR 52.21(i)(8)]. In addition, if EPA has not established an acceptable ambient monitoring method for the pollutant, monitoring is not required.

Submission of pre-construction monitoring data should not be required for this Project because, as shown in Table 3-4, the proposed Project's impacts are predicted to be below the applicable *de minimis* monitoring concentration levels for all pollutants except O₃. The Project's VOC emissions are less than the monitoring emission level of 100 TPY for O₃, but NO_x emissions are greater than 100 TPY. Existing ambient O₃ air quality data in the region demonstrate attainment of the AAQS. For SAM, although the Project's emissions are greater than the significant emission rate, EPA has established no acceptable monitoring method for this pollutant. Therefore, an exemption from the preconstruction monitoring requirement for sulfuric acid is requested in accordance with the PSD regulations.

3.5.4 GEP Stack Height Impact Analysis

The GEP stack height regulations allow any stack to be at least 65 meters [213 feet (ft)] high. The proposed HRSG stacks will be 165 ft. GEP stack height evaluations were also made for the other proposed sources. These stack heights do not exceed the applicable GEP stack heights. However, as discussed in Section 6.0, Air Quality Modeling Approach, building downwash effects must be considered in the modeling analysis if the stack heights are less than GEP. As a result, the potential for downwash of emissions from the CTs and other sources caused by nearby structures is included in the modeling analysis.

3.5.5 Nonattainment Rules

The Project will be located in Effingham County, which is classified as an attainment area for all criteria pollutants. Therefore, the nonattainment rules do not apply to this Project.

3.5.6 Maximum Achievable Control Technology

Emissions of HAPs for the Project and existing facility will be less than 10 TPY of a single HAP and 25 TPY of all HAPs. Therefore, MACT regulations are not applicable to the Project.

3.5.7 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), an allowance system (Part 73), continuous emission monitoring (Part 75), excess emission procedures (Part 77), and appeal procedures (Part 78). The Georgia EPD has implemented rules that are consistent with the federal permit regulations applicable to facilities affected by the requirements of Title IV of the CAA Amendments.

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 proposed Project for the purposes for obtaining a permit and allowances, as well as emissions monitoring. New units are required to obtain permits under the program by submitting a complete application 24 months before the later of January 1, 2000, or the date on which the unit begins serving an electric generator greater than 25 MW. The Effingham Power Plant has an Acid Rain Permit for the existing CTs. An application is submitted in Attachment B to revise the existing Plant Acid Rain permit.

Continuous emission monitoring (CEM) for SO₂ and NO_x is required for gas- and oil-fired affected units. SO₂ emissions for natural gas may be determined using procedures established in Appendix D, 40 CFR Part 75. Carbon dioxide (CO₂) 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 CEM requirements including QA/QC procedures are, in general, more stringent than those specified in the NSPS for Subpart KKKK. 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 Project will be required to either install CEM for NO_x or establish predictive emission monitors (PEMs) to meet the Part 75 requirements.

The 1990 CAA Amendments also established a federally mandated air operating permitting program. The program requires states to adopt regulations consistent with the CAA and the implementing regulations promulgated by EPA in 40 CFR 70. The program applies to "Title V or Part 70" sources that include major stationary sources of air pollutants. The State of Georgia has adopted the requirements of 40 CFR 70 in Georgia Rule 391-3-1-.03(10), which specify that all applicable sources, such as those

proposed for this Project, have a Part 70 permit to operate. After construction of the proposed Project, an application will be submitted to revise the existing Tile V permit of the Effingham Power Plant.

The 1990 CAA Amendments required both the EPA and the Occupational Safety and Health Administration (OSHA) to issue regulations that would help prevent accidental releases of hazardous chemicals. EPA was required to address the consequences of accidental releases beyond a facility's property while OSHA was required to address the consequences on the facility's property. The EPA met their obligation with the promulgation of 40 CFR 68, Accidental Release Prevention Requirements: Risk Management Programs Under the Clean Air Act Section 112(r)(7), in June 1996. The rule applies to all stationary sources that have a regulated substance present in a process in more than the listed threshold quantity. If the threshold quantity for a regulated substance is exceeded, then the facility would need to develop a risk management plan. Aqueous NH_3 is a regulated substance if its concentration is 20 percent or more in a mixture. Since the aqueous NH_3 proposed for the SCR system for this Project will be in a mixture that contains less than 20-percent NH_3 , the Project does not need to develop a risk management plan as specified in the rule. However, the Project is subject to the general duty clause under Section 112(r)(1) of the CAA. The general duty clause directs owners and operators of stationary sources to identify hazards that may result from accidental releases, to design and maintain a safe facility, and to minimize the consequences of releases when they occur. The general duty clause applies to all stationary sources that have any "extremely hazardous substance" that are not limited to the list of regulated substances under Section 112(r) or under OSHA's regulations.

The CAIR program, a market-based cap-and-trade program to limit NO_x and SO_2 emissions, generally applies to stationary boilers and CTs that fire any amount of fossil fuel at any time and serve a generator with a nameplate capacity of more than 25 MW producing electricity for sale. The CTs for this Project have a generation capacity greater than 25 MW and the electricity generated will be sold to the grid. The CAIR program will, therefore, apply to the CTs. The Project will obtain the appropriate number of allowances for commercial operations, including securing any set-asides made available by Georgia EPD.

On October 30, 2009, the EPA published a final regulation for the Mandatory Reporting of Greenhouse Gases (GHGs) in the Federal Register. The rule was incorporated into Title 40, Part 98 of the Code of Federal Regulations (40 CFR 98). The GHG Mandatory Reporting Rule requires annual reporting of emissions of GHGs by certain source categories, as well as by suppliers of fuel, fossil fuels and industrial GHGs. The GHG emissions are defined as CO_2 , methane (CH_4), nitrous oxide (N_2O), and certain fluorinated gases.

Beginning in calendar year 2010, electric generating facilities subject to the Acid Rain Program, or that contain electric generating units that collectively emit 25,000 metric tonnes of CO_2 equivalent (CO_2e) will be required to report their annual GHG emissions to EPA.

For each electricity generating unit that is subject to the requirements of the Acid Rain Program or is otherwise required to monitor and report to EPA CO₂ emissions year-round according to 40 CFR 75 must report under Subpart D the annual mass emissions of CO₂, N₂O, and CH₄.

On June 3, 2010, EPA released the PSD and Title V Greenhouse Gas Tailoring Rule to require a broad range of facilities to reduce their GHG emissions under the CAA. EPA is tailoring the applicability criteria that determine which stationary sources and modification projects become subject to permitting requirements for GHG emissions under the PSD and Title V programs of the CAA. This rulemaking is necessary because without it, PSD and Title V requirements would apply, as of January 2, 2011, at the 100 or 250 TPY levels provided under the CAA.

Beginning in January 2011, if facilities modify their operations and increase emissions of other pollutants covered by the CAA as well as increase GHG emissions by 75,000 TPY, they will be required to conduct a BACT analysis for GHG emissions. Starting in July 2011, all newly built facilities that emit more than 100,000 TPY of GHG will come under the requirements of the CAA for those GHG emissions.

EPA has not determined BACT levels nor provided guidance in evaluating what constitutes BACT for CO₂ and other GHG emissions. Similar to other pollutants, BACT will be determined on a case-by-case basis, considering cost and effectiveness of the different control options. EPA is now developing these BACT guidelines. EPA will also begin another rulemaking process next year to address smaller CO₂ sources, but will not require permits for small emitters until at least April 30, 2016.

4.0 BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS

4.1 Introduction

The 1977 CAA Amendments established requirements for the approval of pre-construction permit applications under the PSD program. As discussed in Subsection 3.2.2, one of these requirements is that BACT be applied to all applicable pollutants. This section presents the proposed BACT for these pollutants. The approach to the BACT analysis is based on the regulatory definitions of BACT, as well as consideration of EPA's current policy guidelines requiring a "top-down" approach. A BACT determination requires a site-specific analysis of the technical, economic, environmental, and energy impacts of the proposed and alternative control technologies [see Rule 62-212.400 of the Florida Administrative Code (F.A.C.)].

The "top-down" approach consists of the following five steps, as described in the New Source Review Workshop Manual-Draft (EPA, 1990):

- 1) Identification of all available control technologies
- 2) Elimination of technically infeasible control options
- 3) Ranking of the technically feasible control technologies based on their effectiveness
- 4) Evaluation of the economic, environmental, and energy impacts of the feasible control options
- 5) Selection of BACT based on consideration of the above factors

The PSD regulations require that new major stationary sources and major modifications to existing major sources undergo a control technology review for each pollutant that may potentially be emitted above significant amounts. In the case of the proposed Project, PM/PM₁₀/PM_{2.5}, NO_x, CO, and VOC emissions require a BACT analysis utilizing the top-down approach. In each case, BACT is an emission limitation that meets the maximum degree of emission reduction after taking into account the proposed Project's specific economic, environmental, and energy impacts, as well as consideration of the application of the technologies proposed. If it is impractical to impose an emission limit, a work practice standard may be specified.

As indicated previously, beginning in January 2011, if facilities modify their operations and increase emissions of other pollutants covered by the CAA as well as increase GHG emissions by 75,000 TPY, they will be required to conduct a BACT analysis for GHG emissions. Although currently not required, Georgia EPD has requested that a BACT analysis be performed for CO₂, the primary GHG for this Project.

An overview of the BACT analysis is presented in Section 4.2, and the following sections provide the required BACT analysis.

4.2 Overview of Proposed BACT

Since 2001, the Georgia EPD has issued six PSD permits with BACT determinations for projects involving natural gas and/or fuel oil-fired combined cycle CTs. These decisions for CTs have included the use of advanced DLN combustors and a SCR system for limiting emissions of NO_x, good combustion practices and oxidation catalyst for minimizing CO and VOC emissions, and the use of clean fuels such as pipeline-quality natural gas or ultra low-sulfur diesel for control of other emissions including PM₁₀ and PM_{2.5}. The stack exhaust NO_x concentration levels have ranged from 2.5 to 3.0 ppmvd corrected to 15-percent O₂ in these determinations.

The BACT limits proposed for the expansion project at Effingham Power Plant are consistent with the PSD permits for the CTs and other emission units. The BACT limits for this Project are as follows:

- BACT for NO_x
 - CTs
 - 2.5 ppmvd at 15-percent O₂ when firing natural gas, using state-of-the-art DLN combustion technology and SCR
 - 10 ppmvd at 15-percent O₂ when firing fuel oil, using water injection and SCR
 - Gas heater and auxiliary boiler
 - Low NO_x burners
- BACT for CO
 - CTs
 - Good combustion practices for both natural gas and fuel oil firing
 - Natural gas firing
 - 3.0 ppmvd at 15-percent O₂ without duct firing
 - 10.5 ppmvd at 15-percent O₂ with duct firing
 - Fuel oil-firing
 - 20.0 ppmvd at 15-percent O₂ without duct firing
 - 23.3 ppmvd at 15-percent O₂ with duct firing
 - Gas heater and auxiliary boiler
 - Good combustion practices
- BACT for VOC
 - CTs
 - Good combustion practices for both natural gas and fuel oil firing
 - Natural gas-firing
 - 1.4 ppmvd at 15-percent O₂ without duct firing
 - 2.0 ppmvd at 15-percent O₂ with duct firing
 - Fuel oil-firing
 - 3.5 ppmvd at 15-percent O₂ without duct firing
 - 4.6 ppmvd at 15-percent O₂ with duct firing

- Gas heater and auxiliary boiler
 - Good combustion practices
- BACT for PM₁₀/PM_{2.5}
 - CTs
 - Natural gas firing
 - Use of pipeline-quality natural gas with sulfur content no more than 0.5 percent by weight
 - 0.0084 lb/MMBtu without duct firing
 - 0.0062 lb/MMBtu with duct firing
 - Fuel oil-firing
 - Ultra low-sulfur distillate fuel with 0.0015-percent sulfur content (by weight)
 - Limited to 1,000 hours per year per turbine
 - 0.0153 lb/MMBtu without duct firing
 - 0.0103 lb/MMBtu with duct firing
 - PM_{2.5} emissions from the CTs are assumed to be same as PM₁₀ emissions
 - Gas heater and auxiliary boiler
 - Use of pipeline-quality natural gas with a maximum sulfur content of 0.5 grains/100 scf
 - Cooling towers
 - Drift eliminators from the main 10-cell mechanical draft cooling tower and the 6-cell inlet chiller cooling tower
 - Drift rate from the cooling towers limited to 0.001 percent
- BACT for CO₂
 - CTs, gas heater, and auxiliary boiler
 - Natural gas firing

4.3 Combined Cycle CTs

This section contains the BACT analysis for the NO_x, CO, VOC, and PM/PM₁₀/PM_{2.5} emissions from the combined cycle CTs.

4.3.1 Nitrogen Oxides

4.3.1.1 Previous BACT Determinations

As part of the BACT analysis, a review was performed of previous BACT determinations issued within the last 10 years (i.e., since 2000) for NO_x emissions from combined cycle CTs listed in the RACT/BACT/LAER Clearinghouse (RBLC) on EPA's web page. A summary of the BACT determinations for natural gas- and fuel oil-fired CTs are presented in Tables 4-1 and 4-2, respectively. Only large CTs with more than 100 MW electricity output or more than 1,000 MMBtu/hr heat input were included in the tables. These tables also include determinations from major source permits available on the Georgia EPD website and in other recent relevant BACT analysis reports.

As shown in Table 4-1, it is evident that the overwhelming majority of BACT emissions limits over the last 3 years for natural gas firing CTs range between 2 and 3.5 ppmvd corrected at 15-percent O₂. Almost all determinations are based on DLN and SCR. Table 4-2 shows that for oil-firing CTs, all BACT determinations are based on water injection and SCR with emissions limits ranging between 6 and 42 ppmvd at 15-percent O₂.

Georgia EPD has issued several permits for natural gas-fired CTs since 2001 and have established BACT for NO_x emissions from these CTs as DLN and/or SCR with a stack NO_x concentration of 2.5 ppmvd or higher. The most recent BACT determination for an oil-fired CT in Georgia is for the Savannah Electric's McIntosh Combined Cycle Plant in Effingham County in 2003 (permit issued April 17, 2003), which is based on water injection and SCR with an emission limit of 6 ppmvd at 15-percent O₂.

4.3.1.2 Identification of Potentially Applicable Control Technologies

A list of potential control technologies for controlling NO_x emissions from the fuel gas heater are identified below.

Water Injection

The injection of water or steam in the combustion zone of CTs reduces the flame temperature with a corresponding decrease of NO_x emissions. The amount of possible NO_x emissions reduction depends on the combustor design and the water-to-fuel ratio employed. An increase in the water-to-fuel ratio will cause a concomitant decrease in NO_x emissions until flame instability occurs. At this point, operation of the CT becomes inefficient and unreliable, and significant increases in products of incomplete combustion result (i.e., CO and VOC emissions). In modern applications, water injection is used only for units firing fuel oil.

DLN Combustors

DLN combustors, which are offered for conventional CTs manufactured by GE, Siemens, Mitsubishi Heavy Industries (MHI), and ABB, can achieve NO_x emissions concentrations as low as 9 ppmvd or less when firing natural gas. All these vendors have offered DLN combustors on advanced heavy-duty industrial units. Formation of thermal NO_x, which is a product of combustion, is inhibited by using combustion techniques where the natural gas and combustion air are premixed before ignition. For the combined cycle CTs being considered for the Project, the standard combustion chamber design includes the use of DLN combustor technology.

Selective Catalytic Reduction

SCR is a process for controlling emissions of NO_x from stationary sources. The basic principle of SCR is the reduction of NO_x to nitrogen (N₂) and water (H₂O) by the reaction of NO_x and ammonia (NH₃) within a catalyst bed. The primary reactions occurring in SCR require O₂, so that the catalyst performs more effectively at O₂ levels above 2 to 3 percent.

Several different catalysts are available for use at different exhaust gas temperatures. The longest and most common catalysts in use are base metal catalysts, which typically contain titanium and vanadium oxides and which may also contain molybdenum, tungsten, and other elements. Base metal catalysts are useful between 450 and 800°F. For high temperature operation (675 to over 1,100°F), zeolite catalysts may be used. In clean, low-temperature (350 to 550°F) applications, catalysts containing precious metals such as platinum and palladium are useful.

The mechanical operation of an SCR system is quite simple. It consists of a reactor chamber with a catalyst bed, composed of catalyst modules and an NH₃ handling and injection system, with the NH₃ injected into the flue gas upstream of the catalyst. There are no moving parts. Other than spent catalyst, the SCR process produces no waste products.

In principle, SCR can provide reductions in NO_x emissions approaching 100 percent. (Simple thermodynamic calculations indicate that a reduction of well over 99 percent is possible at 650°F.) In practice, commercial SCR systems have met control targets of over 90 percent in many cases.

SCR is cost effective for natural gas- or fuel oil-fired CTs. Less catalyst is required since the waste gas stream has lower levels of NO_x, sulfur, and PM. Combined cycle CTs frequently use SCR technology for NO_x reduction. A typical combined cycle SCR design places the reactor chamber after the super heater within a cavity of the HRSG system. The flue gas temperature in this area is within the operating range for base metal-type catalysts. For combined cycle CTs, SCR is considered an available, demonstrated technology.

SCONox Process

Goal Line Environmental Technologies developed the SCONox, a relatively new multi-pollutant post-combustion technology, which utilizes a coated oxidation catalyst to oxidize and remove NO_x and CO without a reagent such as NH₃. Now offered by EmeraChem (formerly Goal Line), the technology is marketed under the name EMx™.

The SCONox system consists of a platinum-based catalyst coated with potassium carbonate (K₂CO₃) to oxidize CO to CO₂ and NO to NO_x. CO₂ generated in the catalyst bed is exhausted to the atmosphere with the flue gas, while NO₂ absorbs onto the catalyst to form potassium nitrite (KNO₂) and potassium nitrate (KNO₃). Periodically, dilute hydrogen gas is passed across the catalyst to regenerate the potassium carbonate coating. The regeneration step converts KNO₂ and KNO₃ into K₂CO₃, water, and nitrogen gas. In order to maintain continuous operation during catalyst regeneration, the system is furnished in arrays of five-module catalyst sections. During operation, four of the five modules are online and treating flue gas, while one module is isolated from the flue gas for regeneration. NO_x reduction in the system occurs in an operating temperature range of 300 to 700°F and, therefore, must be installed in the appropriate temperature section of a HRSG.

A regeneration cycle is typically set to last for 3 to 5 minutes. Regeneration gas is produced by reacting natural gas with O_2 present in ambient air. The SCONOx system uses a gas generator to produce hydrogen and CO_2 . For SCONOx systems installed in locations of the HRSG above $500^\circ F$, a separate regeneration gas generator is not required. Instead, regeneration gas is produced by introducing natural gas directly across the SCONOx catalyst that reforms the natural gas.

The SCONOx system catalyst is subject to reduced performance and deactivation due to exposure to sulfur oxides. For this reason, an additional catalytic oxidation/absorption system (SCOSOx) to remove sulfur compounds is installed upstream of the SCONOx catalyst. The SO_2 is oxidized to sulfur trioxide (SO_3) by the SCOSOx catalyst. The SO_3 is then deposited on the catalyst and removed from the catalyst when it is regenerated. The SCOSOx catalyst is regenerated along with the SCONOx catalyst.

The SCONOx catalyst must be recoated, or “washed” every 6 months to 1 year. The frequency of washing is dependent on the sulfur content in the fuel and the effectiveness of the SCOSOx catalyst. The “washing” consists of removing the catalyst modules from the unit and placing each module in a K_2CO_3 reagent tank, which is the active ingredient of the catalyst. The SCOSOx catalyst also requires washing.

EmeraChem states that their EMxTM technology (the second-generation of the SCONOx NO_x absorber technology) is capable of reducing gas-fired NO_x emissions to less than 1.0 ppm, release undetectable levels of CO, reduce VOC emissions by >90-percent, reduce fine PM by 30 percent, and reduce sulfur emissions by 95 percent.

Commercial experience with the SCONOx control system is limited. The NO_x reduction system was commercially demonstrated first at the 32-MW (GE LM2500 turbine) Sunlaw Federal Cogeneration Facility located in Vernon, California. NO_x emissions from the process were <2 ppm during 100-percent operation, and <1 ppm for 90-percent operation. Other installations of the technology include a 15-MW (Solar Titan 130 turbines) installation at the University of California, San Diego, and a 45-MW (Alstom GTX100 turbine) installation at the City of Redding Municipal Electric Plant. A number of smaller installations are also operating – two 5-MW installations at the Wyeth BioPharma cogeneration facility, Andover, Massachusetts, and a 5-MW installation at the Montefiore Medical Center, Bronx, New York. Actual NO_x emissions from these smaller installations are typically below 1.5 ppm, with substantial periods below 1.0 ppm.

EmeraChem states that the process is scalable. Alstom Power, one of the EMxTM licensees, engineered and installed the technology on one of their GTX100 (43-MW class) gas turbines. This size and design is a reproducible module that would be replicated several times for larger installations. Alstom has already produced preliminary designs for several standard-size plants that match standard sizes of larger turbines.

The number of permitted and operating EMx[™] installations is growing, and the future of the EMx[™] technology is very promising. Cummins Engine Company, one of EmeraChem's equity investors, has helped apply the technology to internal combustion engines – particularly diesel engines. Despite the future promise commercial experience to date with the SCONOx control system is limited to just a few small units. The Project's combustion turbines are approximately 200 MW each and there is no experience of the SCONOx system on turbines of this size.

XONON[™] Catalytic Combustor

The XONON[™] Combustion System is a catalytic combustion system developed by Catalytica Energy Systems, Inc., that is designed to avoid high temperatures created in conventional combustors. The XONON[™] combustor utilizes a catalyst integrated into the gas turbine combustor to limit temperature below the temperature where NO_x is formed. It also lowers CO and VOC emissions.

The XONON[™] technology is installed as an integral part of the combustor. Conventional combustion fuel and air are supplied to combustor; however, rather than combusting the fuel in a flame, the XONON[™] system combusts the fuel using a catalyst at lower temperatures. Fuel and air are thoroughly mixed prior to entering a catalyst region that acts to combust the fuel, releasing its energy. The XONON[™] catalyst module consists of a channel structure whereby the fuel-air mixture readily passes through the channels coated with the catalyst. As fuel and O₂ molecules contact the channel walls, the molecules and catalyst interact and are rearranged at temperatures well below those of flame combustion. Energy is extracted from the fuel in this manner, producing CO₂ and water byproducts. Nitrogen molecules are not involved in the XONON[™] chemistry and pass through the channels unchanged, thereby preventing the formation of NO_x.

The XONON[™] technology was first designed into the combustor of a 1.4-MW Kawasaki Model M1A-13A gas turbine at Silicon Valley Power in Santa Clara, California, in 1999. Since its installation, the turbine has operated as a demonstration of XONON[™]'s performance. The California EPA's Air Resources Board (CA EPA, 2004) evaluated NO_x and CO CEM system data and concluded that XONON[™] achieved a NO_x level of 2.5 ppmvd at 15-percent O₂ and a CO level of 6.0 ppmvd at 15-percent O₂.

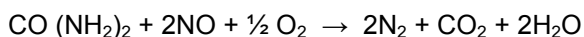
Other commercial installations of the XONON[™] technology include a 1.5-MW Kawasaki M1A-13X installation at Sonoma Development Center in Eldridge, California, and a 1.4-MW Kawasaki GPB15X installation at Plains Exploration & Production Company in San Luis Obispo, California. The Eldridge installation's expected performance was 3 ppmvd NO_x and 10 ppmvd CO. According to the manufacturer, the unit has consistently achieved continuous NO_x emission levels below the emission target, and on the average, NO_x emissions are under 2.0 ppmvd at 15-percent O₂. Based on the manufacturer's report, the unit at the Plains Exploration & Production Co. has achieved NO_x emissions around 0.8 ppmvd at 15-percent O₂ on the average.

Kawasaki Gas Turbines-Americas started selling GPB 15X generators including a 1.4-MW M1A-13X gas turbine equipped with XONON™ in December 2000. Furthermore, Catalytica Energy Systems is working with GE to incorporate XONON™ into their GE10 gas turbines (11.3 MW) and Solar Turbines for use in their Solar Taurus 70 gas turbines.

In September 2006, the XONON™ Combustion System (referred to as the XONON™ Cool Combustion® technology) was sold to Kawasaki Heavy Industries, Ltd. (KHI). Kawasaki is currently making the technology available to the gas turbine generators in the 1- to 1.4-MW range (KHI, 2008).

NOxOUT Process

The NOxOUT process originated from the initial research by the Electric Power Research Institute (EPRI) in 1976 on the use of urea to reduce NO_x. EPRI licensed the proprietary process to Fuel Tech, Inc., for commercialization. In the NOxOUT process, aqueous urea is injected into the flue gas stream ideally within a temperature range of 1,600 to 1,900°F. In the presence of O₂, the following reaction results:



The amount of urea required is most cost-effective when the treatment rate is 0.5 to 2 moles of urea per mole of NO_x. In addition to the original EPRI urea patents, Fuel Tech claims to have a number of proprietary catalysts capable of expanding the effective temperature range of the reaction to between 1,600 and 1,950°F. Advantages of the system are as follows:

- Low capital and operating costs as a result of use of urea injection
- The proprietary catalysts used are nontoxic and nonhazardous, thus eliminating potential disposal problems

Disadvantages of the system are as follows:

- Formation of NH₃ from excess urea treatment rates and/or improper use of reagent catalysts
- Sulfur trioxide (SO₃), if present, will react with NH₃ created from the urea to form ammonium bisulfate, potentially plugging the cold-end equipment downstream

Commercial application of the NOxOUT system has been limited to oil- and coal-fired boilers and municipal solid waste combustors and has not been demonstrated on any combined cycle gas turbines (FTEK, 2008a). The NOxOUT ULTRA process is an approach to convert urea reagent to NH₃ for use on SCR system. The NOxOUT ULTRA system has been demonstrated on a 90-MW GE 7EA gas turbine. However, it is not known to have been installed on any large gas turbines for commercial operation (FTEK, 2008b).

Thermal DeNO_x

Thermal DeNO_x is Exxon Research and Engineering Company's patented process for NO_x reduction. The process is a high-temperature selective noncatalytic reduction (SNCR) of NO_x using NH₃ as the reducing agent. Thermal DeNO_x requires the exhaust gas temperature to be above 1,800°F. However, use of NH₃ plus hydrogen lowers the temperature requirement to about 1,000°F. For some applications, the high temperature must be achieved by additional firing in the exhaust stream before NH₃ injection.

The only known commercial applications of Thermal DeNO_x are on heavy industrial boilers, large furnaces, and incinerators that consistently produce exhaust gas temperatures above 1,800°F. There are no known applications on or experience with combined cycle units. Temperatures of 1,800°F require alloy materials constructed with very large piping and components since the exhaust gas volume would be increased by several times. As with the NO_xOUT process, high capital, operating, and maintenance costs are expected because of material requirements, an additional natural gas-fired exhaust heater system, and fuel consumption. Uncontrolled emissions would increase because of the additional fuel burning.

Selective Non-Catalytic Reduction

SNCR is a post-combustion NO_x emission control technology that reduces NO_x into nitrogen gas and water vapor by reacting the flue gas with a reagent. SNCR systems can either use NH₃ or urea as reagents. The chemical reaction for this technology is driven by high temperatures normally found in combustion sources, typically from 1,600 to 2,100°F. SNCR is "selective" in that the reagent reacts primarily with NO_x.

SNCR is a proven and reliable technology. SNCR was first applied commercially in 1974 and has been installed on approximately 400 applications worldwide. Applications include utility boilers and a broad range of industrial applications including wood-fired boilers, coal-fired boilers, co-generation boilers, pulp and paper boilers, steel industry furnaces, refinery process units, process heaters, cement kilns, municipal waste combustors, glass-melting furnaces, hazardous waste incinerators, and other combustion-type sources. Urea-based SNCR has been applied commercially to sources ranging in size from a 60-MMBtu/hr (gross heat input) paper mill sludge incinerator to a 640-MW pulverized coal-fueled, wall-fired electric utility boiler [Institute of Clean Air Companies (ICAC), 2006].

Non-Selective Catalytic Reduction

Stationary non-selective catalytic reduction (NSCR), as with the automobile sector, involves the use of a three-way catalyst technology to promote the reduction of NO_x to nitrogen and water and simultaneous oxidation of CO and hydrocarbons (HC) to CO₂ and water. NO_x is reduced by the CO and hydrogen (H₂) over the catalyst under slightly rich or stoichiometric conditions to produce CO₂ and water with typical conversion efficiencies in the range 80- to 99-percent achievable together with corresponding decreases in HC and CO.

NSCR can be applied to various spark ignited internal combustion engines that are rich-burn, including natural gas-fueled engines. These types of engines are commonly found in the following applications: gas gathering and storage, gas transmission, power generation, combined heat and power, cogeneration/trigeneration, irrigation, inert gas production, and non-road mobile machinery. NSCR has been used routinely in the automotive industry to reduce vehicular carbon monoxide, hydrocarbons, and NO_x emissions with over a billion catalyst units equipped to automobiles since the mid-1970s. The application of NSCR to stationary gas engines for the control of NO_x and CO first became commercially available in North America in the late 1980s, and more than 5,000 stationary engine installations are in service today (ICAC, 2006).

4.3.1.3 Identification of Technically Feasible Control Alternatives

In this section, the technical feasibility of each potentially applicable control technology is assessed. Those technologies that are found to be technically infeasible will not be considered further in the BACT analysis.

Water Injection

Water injection is a demonstrated technology and considered technically feasible.

DLN Combustors

DLN combustors are available, demonstrated, and technically feasible for units in either simple cycle or combined cycle configurations. The DLN combustion technology alone can achieve 9 ppm (corrected to 15-percent O_2 dry conditions) when firing natural gas.

SCR

SCR has been demonstrated successfully in numerous applications and is considered technically feasible for the proposed combined cycle CTs.

NO_xOUT

As discussed previously, commercial application of the NO_xOUT system is limited mainly to boilers, and the NO_xOUT ULTRA system has not been commercially operated on any large combined cycle gas turbine unit; therefore, these technologies are not considered available or technically feasible. Even if the NO_xOUT process were technically feasible for the proposed Project, the operating temperature range of the combined cycle exhaust is below the NO_xOUT application temperature of 1,600 to 1,950°F. The maximum exhaust gas temperature of the proposed CTs is below 1,100°F. Raising the exhaust temperature to the required level would require installation of a natural gas-fired heater. This would be economically prohibitive and would result in an increase in fuel consumption, an increase in the volume of gases that must be treated by the control system, and an increase in uncontrolled air emissions including NO_x .

Thermal DeNOx

As discussed previously, there are no known applications of the Thermal DeNOx technology to combined cycle units. Since this technology has not been demonstrated for combined cycle units, it is not considered available or technically feasible. Additionally, even if this technology were technically feasible, the operating temperatures for the Thermal DeNOx technology (approximately 1,800°F) would require higher temperature alloy materials constructed with very large piping and components since the exhaust gas volume would be increased significantly. As with the NOxOUT process, high capital, operating, and maintenance costs would be expected because of material requirements, a natural gas-fired exhaust heating system, and fuel consumption. Uncontrolled emissions would increase because of the additional fuel burning.

SNCR

Because the exhaust temperatures from the proposed CTs will not approach the operating temperature window for SNCR, this technology is not technically feasible for this application. The CT exhaust temperature is typically around 1,100°F; the temperature at the exhaust stack downstream of the HRSG is expected to range between approximately 150 and 290°F, which is far below the range of SNCR application. Further, a review of EPA's RBLC database and discussions with control technology vendors do not indicate that SNCR systems have been successfully installed for combined cycle gas turbines. Based on the above limitations (i.e., operating temperature range and lack of actual application to combined cycle units), SNCR is considered technically infeasible.

NSCR

As discussed previously, the NSCR process requires low O₂ content in the exhaust gas stream to be effective. Combined cycle unit exhaust streams have high O₂ levels (greater than 12 percent); and therefore, cannot use the NSCR process. As a result, NSCR is not a technically feasible add-on NO_x control device for combined cycle units.

SCONox

The SCONox control technology is not considered available (and therefore is considered technically infeasible) since it has not been commercially demonstrated on large combined cycle CTs. The proposed CTs are GE 7FA turbines with a nominal generating capacity of 200 MW, approximately four times larger than the 45-MW (Alstom GTX100 turbine) installation at the City of Redding Municipal Electric Plant. Technical problems associated with scale-up of the SCONox technology are unknown given the large differences in machine flow rates. Additional concerns with the SCONox control technology include process complexity (multiple catalytic oxidation / absorption / regeneration systems), reliance on only one supplier, and relatively brief operating history of the technology.

XONON

While the XONON™ catalytic combustion system is applied directly to the CT, application on a large combined cycle unit has not been demonstrated. The XONON™ technology is not considered available since the technology is still in the commercial demonstration stage.

Summary

Based on the preceding discussion, the following technologies are considered to be technically feasible:

- Water injection
- DLN Combustors
- SCR

4.3.1.4 Ranking of Technically Feasible Control Alternatives

Water injection, DLN combustors, and SCR are compatible technologies and can be applied together. Water injection and DLN combustors are pre-combustion technologies and SCR is a post-combustion technology. Considered together, this would be the best control strategy for the control of NO_x. Therefore, a ranking is not required to establish the top technology.

4.3.1.5 Evaluation of Economic, Environmental, and Energy Impacts of Feasible Technologies

Energy Impacts

Water injection and DLN combustors are inherent to the combustion process and do not create any energy impacts. The SCR technology would require additional auxiliary power to overcome the draft loss across the catalyst, to supply hot dilution air for mixing with the NH₃, and to pump NH₃ into the vaporizer.

Environmental Impacts

Water injection or properly tuned DLN combustors do not create negative environmental impacts since these systems are designed and operated to achieve the optimum balance between CO and NO_x emissions. SCR requires storage and use of NH₃, which can cause environmental consequences if not handled and stored properly. NH₃ for the SCR can be in either liquid form or created from solid urea. If liquid NH₃ is used, storage of this substance may trigger requirements as specified by OSHA and the Community Right-to-Know Act. NH₃ slip (i.e., unreacted NH₃ emitted from the stack) is typically 9 ppm or less but has the potential to increase with increasing NH₃ feed rates. Additionally, during the life of the Project, the catalyst would require periodic regeneration or replacement. The used catalyst would be returned to the catalyst supplier for regeneration or would be disposed of in accordance with all applicable regulations.

Economic Impacts

The water injection system and DLN combustors are part of the standard design of modern combined cycle CTs and do not create any economic impacts. The cost of control using SCR has been presented by EPA as \$3,000 to \$6,000 per ton of NO_x removed (EPA, 2003).

4.3.1.6 Selection of BACT and Rationale

Mackinaw Power proposes DLN combustors, water injection, and SCR as BACT for the combined cycle CTs. These technologies are the only feasible control technologies and together, they represent the best NO_x control option. As shown in Tables 4-1 and 4-2, all NO_x BACT determinations for large natural gas and fuel oil-fired CTs are based on these control technologies. The proposed BACT emissions limits are 2.5 ppmvd, corrected to 15-percent O₂ for natural gas firing and 10 ppmvd, corrected to 15-percent O₂ for fuel oil firing, both based on a 24-hour averaging period. There will also be limited hours of fuel oil firing – fuel oil will be limited to 1,000 hours per year per CT.

The most recent NO_x BACT determination in Georgia for natural gas-fired CT is for the Live Oaks Power Project in Glynn County (Permit No. 4911-127-0075-P-02-0, issued April 8, 2010) based on an emissions limit of 2.5 ppmvd at 15-percent O₂. The most recent BACT determination in Georgia for an oil-fired CT is for McIntosh Combined Cycle Facility (permit issued April 17, 2003) in Effingham County based on an emissions limit of 6 ppmvd at 15-percent O₂.

The proposed limits are lower than the NSPS under 40 CFR 60, Subpart KKKK. Mackinaw Power currently operates two identical GE 7FA CTs at the Effingham Plant, which are only natural gas fired, and NO_x emissions are controlled using DLN combustors and SCR system.

4.3.2 Carbon Monoxide (CO) and Volatile Organic Compounds (VOC)

4.3.2.1 Previous BACT Determinations

CO and VOC BACT determinations are presented together in this section since the same emission control technologies are used for both. As part of the BACT analysis, a review was performed of previous CO and VOC BACT determinations for large CTs similar in size to the proposed CTs in EPA's RBLC database. BACT determinations issued within the last 10 years (i.e., since 2000) were identified. A summary of these BACT determinations are presented in Tables 4-3 through 4-6. Tables 4-3 and 4-4 summarize CO BACT determinations for natural gas and oil firing, respectively. Tables 4-5 and 4-6 summarize VOC BACT determinations for natural gas and oil firing, respectively.

From the review of previous BACT determinations, it is evident that almost all CO and VOC BACT determinations for both natural gas and fuel oil-fired CTs have been based on oxidation catalyst systems and good combustion practices (GCP). The use of clean fuel has been named as BACT along with GCP for most determinations for fuel oil-fired CTs. Based on RBLC data for natural gas-fired CTs, there have been seven BACT determinations for CO and three for VOC in Georgia since 2000. These

determinations in Georgia are based on emissions limits in the range of 1.8 to 9.0 ppmvd at 15-percent O₂ for CO and 1.8 to 2 ppmvd at 15-percent O₂ for VOC. Based on RBLC data, there has been only one CO and VOC BACT determination in Georgia for fuel oil-fired CTs – the McIntosh Combined Cycle Facility (permit issued in 2003).

The most recent CO and VOC BACT determination for a large CT in Georgia is for the Live Oaks Power Plant in Glynn County, permit issued in April 2010. The proposed Siemens SGT6 5000F CTs for the Live Oaks Plant are natural gas fired with up to 4,000 hours of duct firing per CT per year. The CO BACT emissions limits are 2.0 ppmvd at 15-percent O₂ without duct firing and 3.2 ppmvd at 15-percent O₂ with duct firing. The VOC BACT emissions limit is 2.0 ppmvd at 15-percent O₂ with and without duct firing. An oxidation catalyst system is proposed as BACT for CO and VOC for the proposed Live Oaks Power Plant.

4.3.2.2 Identification of Potentially Applicable Control Technologies

Combustion is a thermal oxidation process in which carbon and hydrogen contained in a fuel combine with oxygen in the combustion zone to form CO₂ and H₂O. Incomplete combustion occurs when there is not enough oxygen to allow the fuel to react completely to produce CO₂ and water. CO and VOC are a result of incomplete or partial combustion of fossil fuel. Carbon in the fuel that does not experience the required temperature or residence time will form CO or other organic compounds instead of being fully oxidized to CO₂. The important parameters in CO formation are combustion temperatures, fuel residence time, and local stoichiometric ratio of fuel and air (i.e., mixing of fuel and air). Properly designed and operated combustion units typically emit low levels of CO and VOC.

The following control options are evaluated in the BACT analysis. These control options were selected based on recent CO and VOC BACT analysis for large CTs and recent BACT determinations from the RBLC database.

Combustion Controls

CO and VOC emissions are generated from the incomplete combustion of carbon in the fuel and organic compounds. Optimization of the combustion chamber designs and operation practices that improve the oxidation process and minimize incomplete combustion is the primary mechanism available for lowering CO and VOC emissions. This process is often referred to as combustion controls. The combustion system design in modern CTs provides all of the factors required to facilitate complete combustion. These factors include continuous mixing of air and fuel in the proper proportions, extended residence time, and consistent high temperatures in the combustion chamber. As a result, CO and VOC emissions from CTs are inherently low.

GCPs are typically employed to ensure that the CTs are operated as designed.

Oxidation Catalyst

Catalytic oxidation technology is primarily designed to reduce CO emissions (VOC emissions are also reduced to a lesser extent). Oxidation catalysts operate at elevated temperatures. In the presence of an oxidation catalyst, excess O₂ in the exhaust reacts with CO to form CO₂. No chemical reagent is necessary. The oxidation catalyst is typically a precious metal catalyst. None of the catalyst components is considered toxic.

Oxidation catalysts are susceptible to fine particles suspended in the exhaust gases that can foul and poison the catalyst. Catalyst poisoning reduces catalyst activity and pollutant removal efficiencies. The most effective oxidation of CO and VOC emissions is achieved if the catalyst bed is located prior to the HRSG in the high-temperature region.

SCONox Process

The SCONox system previously described in Subsection 4.3.1 also controls CO. The SCONox system employs a single catalyst to simultaneously oxidize CO to CO₂ and NO to NO₂. The SCONox operates at a temperature range of 300 to 700°F and, therefore, must be installed in the appropriate temperature section of a HRSG.

4.3.2.3 Evaluation of Technically Feasible Control Alternatives

In this section, the technical feasibility of each potentially applicable control technology is assessed. Those technologies that are found to be technically infeasible will not be considered further in the BACT analysis.

Combustion Controls

Combustion controls have been applied successfully on combined cycle units similar to those proposed for the Project and are considered technically feasible.

Oxidation Catalyst

Oxidation catalyst technology has been applied successfully on combined cycle units similar to those proposed for the Project and is considered technically feasible.

SCONox

As described in the BACT evaluation for NO_x in Subsection 4.5.1, the application of the SCONox system is limited to a few small turbines with no systems installed on large gas turbines similar to the ones proposed for the Project. Therefore, SCONox is considered to be not technically feasible for the Project.

4.3.2.4 Ranking of Technically Feasible Control Alternatives

Control technologies considered to be technically feasible for the proposed Project are GCP and an oxidation catalyst system. Among the two, oxidation catalyst is an add-on control technology with an estimated control efficiency of more than 80 percent. The combustion system design in modern CTs

provides all of the factors required to facilitate complete combustion. GCP is applied for the current CTs at the Effingham Plant and will be applied for the proposed CTs as well. If the oxidation catalyst system is added, GCP and oxidation catalyst together will clearly provide the most control in terms of control efficiency.

4.3.2.5 Evaluation of Economic, Environmental, and Energy Impacts of Feasible Technologies

Energy

Combustion controls are inherent to the combustion process and do not create any energy impacts. A pressure drop of about 1 to 2 inches of water would be expected across the catalyst bed. Thus, the oxidation catalyst technology requires additional power to overcome the pressure drop and there is an energy cost associated with it. As shown in Table 4-7, the estimated energy penalty is 0.1 percent of the design output of 200 MW, which at the rate of \$0.06/kWh, results in a loss of approximately \$110,000 per year per CT.

The 0.1-percent energy penalty resulting in a loss of 200 kW is equivalent to 1,752,000 kilowatt-hours per year (kW-hr/yr) per CT. Assuming an energy need of 12,000 kW-hr/yr per household, the lost energy would have been sufficient to supply the electrical needs of 146 households.

Environmental

Combustion controls do not create negative environmental impacts since these systems are designed and operated with GCP to achieve the optimum balance between CO/VOC and NO_x emissions. During the life of the CTs, however, the oxidation catalyst would require periodic regeneration or replacement. There would also be additional particulate emissions as a result of an oxidation catalyst. The particulate would result from the conversion of SO₂ to sulfates within the catalyst.

Economic Impacts

An oxidation catalyst system in addition to GCP will provide the most control of CO and VOC emissions. However, this would add considerable capital and operating costs to the proposed system with GCP. Based on a cost quote received from Eriksen in 2008 for a CO oxidation catalyst system for a CT similar in size as the proposed CTs, an economic analysis was performed to add an oxidation catalyst system for each of the proposed CTs. The cost quote was for \$3.46 million for two oxidation catalyst systems, which included a \$1.99 million for the catalyst system and \$1.47 million for design, installation, and materials. These costs were not adjusted for inflation.

The cost analysis, presented in Table 4-7 was conducted following procedures and factors from EPA's Air Pollution Control Cost Manual (sixth edition, January 2002). As shown, using a standard capital recovery factor of 0.1098 (15 years at 7-percent interest), the annualized cost of the capital investment is \$283,000 per year per CT. Additional annualized operating cost to operate the oxidation catalyst system is

estimated at \$346,000, which includes direct and indirect operating costs. The total annual cost is \$629,000 per year per CT.

Since the oxidation catalyst system can control both CO and VOC, the cost effectiveness calculation presented in Table 4-8 shows a combined cost effectiveness number for CO and VOC emissions control. The CO and VOC emissions reductions were calculated from the baseline worst-case annual emissions (see Table 2-4 in Section 2.0) for each. A control efficiency of 80 percent was used to estimate the post-oxidation catalyst emissions for each scenario except for the natural gas-only firing scenario. The proposed CO emission rate for natural gas firing without duct firing and without the oxidation catalyst is only 3.0 ppmvd. Based on previous BACT determinations with oxidation catalyst systems, it is assumed that a CO BACT limit of 2.0 ppmvd would have been proposed for natural gas firing with an oxidation catalyst system. Therefore, the oxidation catalyst system will be required to control the CO emissions for the natural gas-firing scenario from 3.0 ppmvd to 2.0 ppmvd. A control efficiency of 80 percent will reduce CO emissions from the natural gas-firing with duct firing scenario from 10 ppmvd to 2 ppmvd. For fuel oil firing, 80-percent control will reduce CO emissions from 23.0 ppmvd to 4.6 ppmvd. It was assumed that the oxidation catalyst system will also reduce startup and shutdown emissions by 80 percent. As shown in Table 4-8, the total CO emissions reduction will be 183 TPY for each CT.

The VOC emissions reduction was also estimated in a way similar to CO. A control efficiency of 50 percent was used for VOCs. As shown in Table 4-8, the total VOC emissions reduction will be 22.7 TPY for each CT. Total CO and VOC emissions reduction was estimated to be 193 TPY for each CT. Cost effectiveness was calculated based on the total annualized cost and total CO and VOC emissions reduction. As shown, the cost effectiveness was estimated to be more than \$3,200 per ton of CO or VOC emissions. This cost is considered to be high for BACT determination.

4.3.2.6 Selection of BACT and Rationale

The evaluation of the energy, environmental, and economic impacts demonstrates that an oxidation catalyst system will not be cost effective for the proposed CTs. Therefore, Mackinaw Power proposes GCP as the BACT for CO and VOC with the following emissions limits for CO and VOC:

CO – Natural Gas Firing

- Without duct firing – 3.0 ppmvd at 15-percent O₂
- With duct firing – 10.5 ppmvd at 15-percent O₂

CO – Fuel Oil Firing

- Without duct firing – 20.0 ppmvd at 15-percent O₂
- With duct firing – 23.3 ppmvd at 15-percent O₂

VOC – Natural Gas Firing

- Without duct firing – 1.4 ppmvd at 15-percent O₂
- With duct firing – 2.0 ppmvd at 15-percent O₂

VOC – Fuel Oil Firing

- Without duct firing – 3.5 ppmvd at 15-percent O₂
- With duct firing – 4.6 ppmvd at 15-percent O₂

Moreover, the air quality impacts at the proposed uncontrolled GCP CT emission rate are predicted to be much less than the PSD significant impact levels. The maximum predicted CO impacts are less than 1 percent of the applicable ambient air quality standards (see Section 6.0). Therefore, no significant environmental benefit would be realized by the installation of a CO catalyst.

4.3.3 Particulate Matter (PM/PM₁₀/PM_{2.5})

4.3.3.1 Previous BACT Determinations

A small amount of PM/PM₁₀/PM_{2.5} emissions, collectively referred to as “PM” will result from the combustion of pipeline quality natural gas and ultra low-sulfur fuel oil in the CTs, which are generally low emitters of PM. NSPS Subpart KKKK, which specifies performance standards for stationary CTs, does not set any PM emissions limits for CT operators.

As part of the BACT analysis, a review was performed for previous BACT determinations within the last 10 years for PM emissions from natural gas and fuel oil-fired large CTs in EPA’s RBLC web page. A summary of these BACT determinations are presented in Tables 4-9 and 4-10 for natural gas and fuel oil firing, respectively.

From the review of previous BACT determinations, it is evident that all PM BACT determinations are based on GCP and the use of natural gas or low-sulfur fuel. Add-on PM control technologies were not selected as BACT for any of the determinations. Georgia EPD has issued six PM BACT determinations for natural gas-fired CTs and one for fuel oil-fired CTs since early 2000 and all determinations are based on GCP or clean fuel. Previous BACT determinations in Georgia have ranged from 0.0064 to 0.011 pound per million British thermal unit (lb/MMBtu) for natural gas-fired CTs and 0.016 lb/MMBtu for McIntosh Combined Cycle Facility’s fuel oil-fired CTs (permit issued in April 2003).

4.3.3.2 Identification of Potentially Applicable Control Technologies

PM is the general term for a mixture of solid particles and liquid droplets present in the emissions stream. PM emissions from turbines primarily result from carryover of noncombustible trace constituents in the fuel. PM emissions can be classified as “filterable” or “condensable” PM. Filterable PM is that portion of the total PM that exists in the stack in either the solid or liquid state. Condensable PM is that portion of the total PM that exists as a gas in the stack but condenses in the cooler ambient air to form particulate

matter. Condensable PM is composed of organic and inorganic compounds and is generally considered to be all less than 1.0 micron in aerodynamic diameter. EPA's Compilation of Air Pollution Emission Factors (AP-42) states in Section 3.1 (Stationary Gas Turbines) – "PM emissions are negligible with natural gas firing and marginally significant with distillate oil firing because of the low ash content."

PM emissions that are less than 10 microns in diameter are referred to as PM₁₀. PM_{2.5} is PM emissions that are less than 2.5 microns in diameter. All PM₁₀ emissions from CTs are considered to be PM_{2.5}. The following control options are evaluated in the PM BACT analysis:

Good Combustion Practices (GCP)

PM emissions from natural gas combustion are inherently low, and combustion controls can further minimize the amount of PM emissions generated due to incomplete combustion in the combined cycle CTs. Optimization of the combustion chamber designs and operation practices that improve the oxidation process and minimize incomplete combustion is the primary mechanism available for lowering PM emissions. This process is often referred to as "good combustion practices." Good combustion chamber design is inherent to modern CTs.

Clean Fuel

One mechanism for the formation of particulate is the oxidation of sulfur compounds, which can precipitate as PM in the exhaust stream. The proposed CTs will burn pipeline-quality natural gas and ultra low-sulfur fuel oil. Both fuels contain very low levels of sulfur; thus, emissions of sulfur and the resulting PM are minimized through the use of these clean-burning fuels.

Fabric Filter Baghouse

A fabric filter baghouse removes particles and condensed metals from a flue gas stream by drawing dust-laden flue gas and condensables through a bank of filter tubes suspended in a housing. A filter cake, composed of the removed particulate, builds up on the "dirty" side of the bag. Periodically, the cake is removed through physical mechanisms (i.e., blast of compressed air from the clean side of the bag, mechanical shaking of the bags, etc.), which causes the cake to fall. The dust is then collected in a hopper and removed.

Electrostatic Precipitator

An electrostatic precipitator (ESP) removes dust or other fine particles from a flue gas stream by charging the particles inductively with an electric field and then attracting the particles to highly charged collector plates, from which they are removed. An ESP consists of a hopper-bottomed box containing rows of plates forming passages through which the flue gas flows. Centrally located in each passage are emitting electrodes energized with a high-voltage, negative polarity direct current. The voltage applied is high enough to ionize the gas molecules close to the electrodes, resulting in a corona current of gas ions from the emitting electrodes across the gas passages to the grounded collecting plates. When passing

through the flue gas, the charged ions collide with, and attach themselves to, fly ash particles suspended in the gas. The electric field forces the charged particles out of the gas stream towards the grounded plates, and there they collect in a layer. The plates are periodically cleaned by a rapping system to release the ash layer into ash hoppers as an agglomerated mass.

Wet Electrostatic Precipitator

A wet electrostatic precipitator (WESP) operates in the same three-step process as a dry ESP: charging, collection, and removal. Unlike with a dry ESP; however, with a WESP, the removal of particles from the collecting electrodes is accomplished by washing the collection surface using liquid, rather than mechanically rapping the collector plates. WESPs are more widely used in applications where the gas stream has a high moisture content, is below the dew point, or includes “sticky” particulate.

Wet Scrubber

Wet scrubbers trap suspended particles by direct contact with a spray of water or other liquid. In effect, a scrubber washes the particulates out of the dirty airstream as they collide with and are entrained by the tiny droplets in the spray. Several configurations of wet scrubbers are in use. In a spray-tower scrubber, an upward-flowing airstream is washed by water sprayed downward from a series of nozzles. The water is re-circulated after it is sufficiently cleaned to prevent clogging of the nozzles. In orifice scrubbers and wet-impingement scrubbers, the air and droplet mixture collides with a solid surface. Collision with a surface atomizes the droplets, reducing droplet size and thereby increasing total surface contact area. These devices have the advantage of lower water-recirculation rates.

Scrubber efficiency depends on the relative velocity between the droplets and the particulates. Venturi scrubbers achieve high relative velocities by injecting water into the throat of a venturi channel—a constriction in the flow path through which particulate-laden air is passing at high speed. As a result, Venturi scrubbers are the most efficient of the wet collectors.

4.3.3.3 Evaluation of Technically Feasible Control Alternatives

Technical feasibility of the potential control options is evaluated below. Those technologies that are found to be technically infeasible will not be considered further in the BACT analysis.

Good Combustion Practices

Good combustion chamber design to minimize incomplete combustion is inherent to modern CTs. GCP is typically employed to operate the CTs at optimum design conditions. GCP is considered technically feasible.

Clean Fuel

Both pipeline quality natural gas and ultra low-sulfur distillate fuel oil are available and feasible for use in the Project.

Add-On Controls

Add-on control devices [including fabric filtration, ESP, wet ESP (WESP), and wet scrubbers] are not technically feasible for the combined cycle CTs because of high volumes of airflow, fine particulate distribution, and inherently low uncontrolled PM emission rates. Consistent with this position and based on the information in EPA's RBLC database, no natural gas- or fuel oil-fired CT has been equipped with an add-on control device.

4.3.3.4 Ranking of Technically Feasible Control Alternatives

GCP and the use of clean fuels such as pipeline-quality natural gas and ultra low-sulfur distillate fuel oil are the only feasible PM control technologies for CTs. These technologies are compatible control strategies and, considered together, they present the best control option for PM from CTs. A ranking is therefore, not required to establish the top technology.

4.3.3.5 Evaluation of Economic, Environmental, and Energy Impacts of Feasible Technologies

Energy

GCP and clean fuels such as pipeline-quality natural gas and ultra low-sulfur fuel oil do not create any energy impacts.

Environmental

No negative environmental impacts are expected from GCP and the use of clean fuels.

Economic

GCP is part of standard operating practice at the Effingham Power Plant and used for the existing CTs at the Plant. Use of GCP for the proposed CTs will not create any economic impacts. Pipeline-quality natural gas is available in close proximity to the site and is not expected to create any adverse economic impacts. Cost of ultra low-sulfur fuel oil is only marginally higher than low-sulfur fuel oil. So there will be some additional cost to burn ultra low-sulfur oil. However, oil firing will be limited and not more than 100 hours per year per CT.

4.3.3.6 Selection of BACT and Rationale

Based on the identification and technical evaluation of the available control technologies, the proposed BACT for PM emissions from the combined cycle CTs is GCP and use of natural gas and ultra low-sulfur fuel oil. The proposed PM emissions rates are:

- Natural gas-firing – 0.0084 lb/MMBtu (without duct firing) and 0.0062 lb/MMBtu (with duct firing)
- Fuel oil-firing – 0.0153 pound per hour (lb/hr) (without duct firing) and 0.0103 lb/hr (with duct firing)

The proposed BACT determination is consistent with the BACT determinations for natural gas- and fuel oil-fired combined cycle CTs found in EPA's RBLC database. The proposed BACT emissions limits are consistent with most BACT emissions limits in Georgia (see Tables 4-9 and 4-10).

4.4 Auxiliary Boiler

This section contains the BACT analysis for the proposed auxiliary boiler. The auxiliary boiler has a maximum design heat input rating of 17 MMBtu/hr and will be exclusively fueled by pipeline quality natural gas. The boiler will be used during the startup and shutdown sequences of the CTs to provide steam to the steam cycle and shorten the cold and warm start duration, thus decreasing start-up emissions. Mackinaw Power proposes to limit the hours of operation of the auxiliary boiler to 2,500 hr/yr. Based on emissions calculation presented in Table 2-7, the auxiliary boiler will potentially emit about 2 TPY of NO_x or CO, 0.11 TPY of VOC, and 0.15 TPY of PM emissions.

A search of EPA's RBLC database was conducted for previous BACT determinations for auxiliary boiler and a summary of previous 5 years of determination is presented in Table 4-11. It is evident that most of the BACT determinations are based on GCP and LNBs. FGR has been used as BACT in addition to LNB for NO_x control in some of the permits. However, these are for large auxiliary boilers with more than 29 MMBtu/hr of heat input rating. The proposed auxiliary boiler for the Project has a heat input rating of 17 MMBtu/hr. Based on the very low baseline emissions, coupled with the limit on operating hours and the results of the RBLC research, add-on controls are not considered to be feasible for the proposed auxiliary boiler.

LNBs are designed to limit NO_x formation by controlling the stoichiometric temperature profiles of the combustion process. This control is achieved by design features that regulate the aerodynamic distribution and mixing of the fuel and air, resulting in one or more of the following conditions: (a) reduced O₂ in the primary flame zone; (b) reduced flame temperature; or (c) reduced residence time at peak temperature. The proposed auxiliary boiler will be equipped with LNB.

Mackinaw Power proposes the following control technologies and emission limits as BACT:

- NO_x – LNB with NO_x limit of 0.098 lb/MMBtu
- CO and VOC – GCP with CO limit of 0.082 lb/MMBtu and VOC limit of 0.0052 lb/MMBtu
- PM/PM₁₀/PM_{2.5} – GCP and use of pipeline quality natural gas with PM/PM₁₀/PM_{2.5} limit of 0.0072 lb/MMBtu

The above proposed BACT emissions limits are consistent with the BACT limits found in the EPA's RBLC database and meet the requirements of the NSPS for industrial-commercial-institutional steam generators as set forth in 40 CFR 60 Subpart Dc.

4.5 Fuel Gas Heater

This section contains the BACT analysis for the proposed fuel heater rated at 8.75 MMBtu/hr. The heaters will be fired by pipeline quality natural gas with maximum sulfur content limited to 0.5 gr/100 scf. Based on the emissions calculation for the fuel heater presented in Table 2-6, the fuel heater has the potential to emit 1.9 TPY of NO_x, 3.1 TPY of CO, 0.2 TPY of VOC, and 0.3 TPY of PM/PM₁₀/PM_{2.5} emissions.

Based on EPA's RBLC database search, a summary of previous BACT determinations for fuel heaters are presented in Table 4-12. As shown, add-on controls have never been applied to a fuel heater. Based on low emissions potential and RBLC research, add-on controls are considered infeasible.

Mackinaw Power proposes the following control technologies and emission limits as BACT for the fuel heater:

- NO_x – GCP with NO_x limit of 0.05 lb/MMBtu
- CO and VOC – GCP with CO limit of 0.082 lb/MMBtu and VOC limit of 0.0052 lb/MMBtu
- PM/PM₁₀/PM_{2.5} – GCP and use of pipeline quality natural gas with PM/PM₁₀/PM_{2.5} limit of 0.0072 lb/MMBtu

The above proposed BACT emissions limits are consistent with the BACT limits found in the EPA's RBLC database and meet the requirements of the NSPS for industrial-commercial-institutional steam generators as set forth in 40 CFR 60 Subpart Dc.

4.6 Cooling Towers

This section contains the BACT analysis for the PM/PM₁₀/PM_{2.5} emissions, collectively referred as "PM" emissions from the proposed mechanical draft cooling towers for the Project – a 10-cell tower for the combined cycle CTs and a 6-cell tower for the inlet chiller units. Cooling towers use a fan to move air through a re-circulated water system. This allows a considerable amount of water vapor and sometimes droplets to be introduced into the surroundings. The use of high-efficiency drift eliminating media to de-entrain droplets from the air flow exiting the cooling tower is a commercially proven technique to reduce PM emissions. The drift eliminators used in cooling towers rely on inertial separation caused by direction changes while passing through the eliminators. Types of drift eliminator configurations include herringbone (blade-type), wave form, and cellular (or honeycomb) designs. The cellular units generally are the most efficient.

Based on the review of EPA's RBLC database, which is presented in Table 4-13, the most stringent BACT limit for cooling towers is drift eliminators with drift rate 0.001 to 0.0005 percent. There are no energy or environmental impacts associated with drift eliminators. Drift eliminators with a drift rate of 0.001-percent is most common and demonstrated in practice. Drift eliminators with 0.0005 percent drift rate is commercially available but are more expensive.

Effingham Power proposes to use high-efficiency drift eliminators with a drift rate of 0.001-percent as BACT for PM emissions from the proposed cooling towers. Water circulation rate for the proposed cooling towers are 155,000 gallons per minute (gpm) and 10,042 gpm for the 10-cell and 6-cell towers, respectively. The maximum TDS concentration in the water is 1,000 ppm by weight.

4.7 Fuel Oil Storage Tank

This section contains the BACT analysis for the proposed 2,350,000-gallon fixed-roof fuel oil storage tank. The tank will be equipped with conservation vent valves. These include both pressure relief valves (to keep fuel vapors in the tank up to a safe pressure) and vacuum relief valves (to allow outside air to enter the tank to avoid a significant vacuum). Such valves are needed to accommodate pressure variations occurring with changes in ambient temperature and fuel level changes associated with filling and dispensing.

Based on the low emissions potential from these sources and the high cost of add-on controls, Mackinaw Power proposes fixed-roof tanks with conservation vent valves as BACT for the fuel storage tank.

4.8 CO₂ BACT Evaluation

There are two broad strategies for reducing CO₂ emissions from stationary combustion processes such as the combustion turbines, auxiliary boiler, and fuel gas heater. The first is to minimize the production of CO₂ through the use of low-carbon fuels. As discussed previously, the use of natural gas reduces the production of CO₂ during the combustion process relative to burning of other fossil fuels.

The second strategy for CO₂ emission reduction is carbon capture and storage (CCS). The inherent design of the combustion turbines, auxiliary boiler, and fuel gas heater produce a dilute CO₂ stream. The CO₂ emissions from the combustion sources theoretically can be captured through pre-combustion methods or through post-combustion methods. In the pre-combustion approach, oxygen instead of air is used to combust the fuel and a concentrated CO₂ exhaust gas is generated. This approach significantly reduces the capital and energy cost of removing CO₂ from conventional combustion processes using air as an oxygen source, but it incurs significant capital and energy costs associated with separating oxygen from the air.

Post-combustion methods are applied to conventional combustion techniques using air and carbon-containing fuels in order to isolate CO₂ from the combustion exhaust gases. Because the air used for combustion contains nearly 80 percent nitrogen, the CO₂ concentration in the exhaust gases is only 5 to 20 percent depending on the amount of excess air and the carbon content of the fuel.

The use of CCS for the combustion sources at the Project would entail significant, adverse energy and environmental impacts due to increased fuel usage in order to meet the steam and electric load requirements of these systems.

BACT for CO₂ emissions for the Project is based on firing pipeline quality natural gas in the CTs (as the primary fuel), fuel gas heater, and auxiliary boiler. Natural gas has the lowest amount of carbon of the fossil fuels. The preferential burning of natural gas is an effective means to reduce CO₂; technically feasible for the CTs, fuel gas heater, and auxiliary boiler; and is an inherent part of the Project design.

5.0 AMBIENT MONITORING ANALYSIS

5.1 Monitoring Requirements

In accordance with requirements of 40 CFR 52.21(m), an air quality analysis must be conducted for each criteria and non-criteria pollutant subject to regulation under the CAA before a major modification is made or a major stationary source is constructed. Criteria pollutants are those pollutants for which AAQS have been established. Non-criteria pollutants are those pollutants that may be regulated by emission standards for which AAQS have not been established. This analysis may be performed by the use of modeling and/or by monitoring the air quality. In addition, if EPA has not established an acceptable ambient monitoring method for the pollutant, monitoring is not required.

Based on the potential emissions from the proposed Project (see Table 3-3), pre-construction ambient monitoring analyses for PM₁₀, PM_{2.5}, NO₂, CO, and O₃ (based on NO_x or VOC emissions) may be required as part of the application. Ambient monitoring analyses are not required if it can be demonstrated that the proposed Project's maximum air quality impacts will not exceed the PSD *de minimis* concentration levels and, for O₃, the proposed facility's potential emissions will not exceed 100 TPY of NO_x or VOC emissions.

As presented in Section 6.0 and shown in Table 3-3, maximum impacts due to the proposed Project only are predicted to be below the PSD *de minimis* concentration levels for all pollutants. As a result, a pre-construction ambient monitoring analysis is not required for PM₁₀, PM_{2.5}, NO₂ and CO as part of the application. It should be noted that EPA has proposed PSD *de minimis* concentration levels for PM_{2.5} but not for the 1-hour average NO₂ concentration. At this time, pre-construction monitoring analyses are not required for these pollutants.

For O₃, the proposed Project's VOC emissions are less than 100 TPY; however, NO_x emissions are more than 100 TPY or more, which would require a pre-construction ambient monitoring analysis.

5.2 Ozone Ambient Monitoring Analysis

Ambient O₃ monitoring data from existing monitoring stations are included in Table 5-1 to satisfy the pre-construction monitoring requirement. Effingham County and adjacent counties are classified as attainment or maintenance areas for O₃. The nearest monitor to the Effingham Plant that measures O₃ concentrations is located in Savannah, Chatham County (Monitor ID No. 13-051-0021), approximately 32 km (20 miles) from the site. The Savannah monitor is considered to be representative of the Effingham Plant area since it is located within 20 miles of the site and in a similar rural setting.

As shown in Table 5-1, the second-highest 1-hour average O₃ concentration measured from 2007 through 2009 in Savannah was 160.9 µg/m³. In addition, the 3-year average of the fourth highest 8-hour average O₃ concentrations was 120.3 µg/m³ and is below the revised 8-hour average O₃ AAQS of 147 µg/m³.

Since existing ambient O₃ air quality data from the region show attainment of the AAQS, Mackinaw Power requests an exemption from the preconstruction monitoring requirement for O₃ in accordance with the PSD regulations.

6.0 AIR QUALITY IMPACT ANALYSIS

6.1 General

This section contains a summary of the methodologies and results of the air quality impact assessments performed to determine compliance of the Project with the NAAQS and PSD increments. Prior to performing the analyses described in this section, an air modeling protocol was submitted to Georgia EPD in March 2010 (see Appendix C) which discussed the air modeling analyses to be performed and the procedures to be used. Additionally, the Federal Land Manager (FLM) for each of the PSD Class I areas located within 300 km of the Project site [i.e., the U.S. Fish and Wildlife Service (USFWS)] was provided an opportunity to review and provide comments on the air modeling protocol to determine if AQRV analyses was required.

Based on subsequent discussions with Georgia EPD (i.e., telephone and email communications), the modeling approach was followed that included the Georgia EPD modeling practices and recommended procedures. In addition, the FLM responded that the AQRV analyses were not required for the PSD Class I areas.

6.2 Significant Impact Analysis

6.2.1 General

The general modeling approach for the significant impact analysis followed the EPA and Georgia EPD modeling guidelines for determining compliance with NAAQS and PSD increments. For each criteria pollutant that will be emitted in excess of the respective PSD significant emission rate due to the proposed project, a significant impact analysis is performed to determine whether the new emission sources associated with the Project, given their stack configuration and other modeling inputs, will result in predicted impacts that are in excess of the EPA SILs (see Table 3-4).

For the Project, emission increases above the PSD significant emission rates (see Section 3-6) occur for the following criteria pollutants:

- NO₂
- PM
- PM₁₀
- PM_{2.5}
- CO
- VOC

Because NAAQS and PSD increments do not exist for PM and since VOC is a precursor to ozone, air impacts for those pollutants are not required.

Until the PSD increments, SILs, and significant monitoring concentrations for $PM_{2.5}$ are finalized and the NSR implementation guideline is finalized, Georgia EPD recommends following the procedures provided in the EPA memorandum, *EPA's Modeling Procedures for Demonstrating Compliance with the $PM_{2.5}$ NAAQS* (EPA Memorandum, March 23, 2010). When addressing compliance with the $PM_{2.5}$ NAAQS, the procedures recommend that the total air quality be based on the highest 5-year average of predicted impacts from modeled sources added to the 3-year average of the 8th highest measured 24-hour concentration for each year (i.e., 98th percentile) for the 24-hour NAAQS and 3-year average of the annual average measured concentration for the annual NAAQS. When addressing the project's compacts for comparison to the SIL, the procedures recommend that the Project's impacts be based on the highest 5-year average of predicted annual and 24-hour values.

For $PM_{2.5}$, EPA has proposed that one of three options could be the SIL but does not presume that the levels are appropriate and recognizes that states could adopt different interim levels with appropriate records. For the 24-hour average, the proposed EPA SIL are 1.2, 4.0, and 5.0 $\mu\text{g}/\text{m}^3$; for the annual average, the proposed EPA SIL are 0.3, 0.8, and 1.0 $\mu\text{g}/\text{m}^3$. For this analysis, the lowest value from the three options was selected as SIL for the modeling analysis.

In addition to $PM_{2.5}$, significant impact analyses are also required for NO_2 , PM_{10} , and CO. Because a SIL for the 1-hour NO_2 concentration currently does not exist, Georgia EPD has recommended an interim SIL of 9.4 $\mu\text{g}/\text{m}^3$ which is 5 percent of the NAAQS of 188 $\mu\text{g}/\text{m}^3$. Similar to the $PM_{2.5}$ modeling approach, when addressing the project's compacts for comparison to the SIL, the Project's impacts can be based on the highest 5-year average of the maximum predicted 1-hour daily values. However, when addressing compliance with the 1-hour NO_2 NAAQS, the total air quality can be based on the highest 5-year average of 8th highest daily predicted 1-hour impacts added to the 3-year average of 8th highest daily measured 1-hour concentration for each year.

6.2.2 Site Vicinity

Current Georgia EPD policies stipulate that, for the annual average NO_2 , PM_{10} and CO significant impact analyses, the highest annual average and highest short-term (i.e., 24-hour or less) concentrations are to be compared to the applicable SILs (see Table 3-1). If the maximum Project-only impacts are equal to or greater than the SIL in the vicinity of the Project, two additional, cumulative source air modeling analyses are required. The first analysis must determine compliance with the NAAQS, and the second analysis must determine compliance with allowable PSD Class II increments.

For the $PM_{2.5}$ significant impact analysis, EPA's interim guidance recommends using the 5-year average of the predicted annual average and highest 24-hour concentrations for comparison to the SIL. If the maximum Project-only impacts are equal to or greater than the SIL in the vicinity of the Project, a more detailed cumulative source modeling analysis is required to demonstrate compliance with the NAAQS.

For the 1-hour NO₂ significant impact analysis, the highest 5-year average of the predicted daily highest 1-hour concentrations is used for comparison to the SIL. If the maximum Project-only impacts are equal to or greater than the SIL in the vicinity of the project, a more detailed cumulative source modeling analysis is required to demonstrate compliance with the NAAQS.

6.2.3 PSD Class I Areas

Generally, if a major new facility or major modification is located within 300 km of a PSD Class I area, then a significant impact analysis is performed to evaluate the impacts of the project alone at the PSD Class I area and to determine the need to perform Class I increment analyses.

The following PSD Class I areas are the only PSD Class I areas located within 300 km of the Project site:

- Wolf Island National Wilderness Area - 101 km
- Okefenokee NWA - 162 km
- Cape Romain NWA - 167 km

If the maximum project-only pollutant-specific impacts are less than the Class I pollutant-specific SIL, the project would be considered to not have a significant impact at the PSD class I areas and assumed to comply with the PSD Class I increments. If the project-only impacts are equal to or greater than the PSD Class I SIL, then additional analyses with background sources are required to determine compliance with PSD Class I increments. In general, these analyses are performed using the CALPUFF modeling system for projects located 100 km or more from the Class I areas.

In addition to PSD Class I increment analysis, AQRV analyses of visibility impairment and acid deposition are generally requested to be performed by the FLM of the Class I areas. However, based on the project's annual emissions and distance from the Class I areas, the FLM may determine that modeling for the project would not show any significant additional impacts to the AQRV. When AQRV impacts are not requested by the FLM, Georgia EPD recommends using a conservative screening modeling procedure with American Meteorological Society and EPA Regulatory Model (AERMOD) to estimate the Project's impacts for comparison to the Class I SIL to address compliance with the PSD Class I increment.

Upon review of the Project's annual emissions and distance that the Project is from the PSD Class I areas, the FLM for the PSD Class I areas, the USFWS, notified Georgia EPD that the Project's impacts are anticipated to not show any significant additional impacts to the AQRV at the PSD Class I areas. As such, analyses of the Project's impacts on AQRV of visibility impairment and acid deposition at the PSD Class I areas are not included in this report because the FLM did not request that AQRV analyses be performed. As a result, AERMOD was used to estimate the project's impacts for comparison to the Class I SIL based on conservative screening procedures recommended by Georgia EPD.

6.3 Cumulative Source Impact Analyses

6.3.1 NAAQS and PSD Class II Analysis

As previously noted, if the project-only impacts are greater than the SIL, detailed air modeling analyses are required to determine total air quality concentrations that incorporate the modeled concentrations of the project and background sources added to a non-modeled background concentration which are then compared to the NAAQS. If allowable PSD increments exist for a particular pollutant and averaging time, a second detailed analysis is required to determine PSD increment consumption from the project and PSD-affecting background sources for comparison to the allowable PSD increments.

As described in Section 6.12 (Model Results), the Project's maximum 1-hour NO₂ and 24-hour average PM_{2.5} impacts are predicted to be greater than the respective presumed SILs. Therefore, additional detailed air modeling analyses must be performed for these pollutants incorporating background sources.

For determining compliance with the NAAQS for PM_{2.5}, EPA's interim policy suggests using the highest 5-year average of the modeled annual and highest 24-hour concentrations based on the 5-year meteorological record. For determining compliance with the 1-hour NO₂ NAAQS, the highest 5-year average of the modeled 8th-highest values (98th percentile) of yearly distribution of the 1-hour daily maximum concentration is used.

6.3.2 PSD Class I Analysis

For each pollutant where maximum predicted impacts exceed the proposed Class I SIL, a cumulative source PSD Class I analysis is required. Since the Project's maximum annual average NO₂ and PM₁₀ impacts were predicted to be less than the proposed Class I SIL, additional cumulative source analyses to determine compliance with the allowable PSD Class I increments were not required.

6.4 Model Selection

The selection of one or more air quality models to estimate maximum air quality impacts must be based on the model's ability to simulate impacts in all key areas surrounding a project site. For predicting concentrations at receptors that are located within 50 km of a project site, EPA and Georgia EPD recommend using the AERMOD dispersion model. For this Project, the AERMOD model was selected and used for predicting concentrations at locations within 50 km from the Project site. In addition, AERMOD was also used for predicting concentrations at 50 km to represent the Project's impacts at the PSD Class I areas following Georgia EPD's screening procedures.

The AERMOD model calculates hourly concentrations based on hourly meteorological data and is applicable for most applications, since it is recognized as containing the latest scientific algorithms for simulating plume behavior in all types of terrain. AERMOD Version 09292 is the most recent available

version on EPA's Internet web site: Support Center for Regulatory Air Models (SCRAM) within the Technology Transfer Network (TTN). A listing of AERMOD features is presented in Table 6-1.

For modeling analyses that will undergo regulatory review, such as PSD permit applications, the following modeling features are recommended by EPA and are incorporated as the regulatory default options in AERMOD:

- Use of elevated terrain algorithms
- Stack-tip downwash
- Missing data processing routines
- 4-hour half-life for exponential decay of SO₂ for urban sources
- Calm wind processing routines

EPA regulatory default options were used to address maximum impacts. Because the area in the vicinity of the Project site is considered to not to be affected by urban heat island effects, this option was not used.

6.5 Meteorological Data

Meteorological data used in AERMOD to predict air quality impacts consisted of a concurrent 5-year period of hourly surface weather observations from the National Weather Service (NWS) office located at the Savannah International Airport (SAV) and upper air sounding data collected at the Charleston International Airport (CLS). The 5-year period of the meteorological data is from 1990 through 1994. The meteorological data record was processed and approved for use by Georgia EPD.

The weather office at SAV is located approximately 30 km east of the Project site and represents the closest primary weather station to the Project.

In addition to the meteorological parameters incorporated into the modeling analysis, AERMOD incorporates land use parameters for determining boundary layer parameters that are used by AERMOD for the dispersion calculations. AERSURFACE reads land use files developed by the U.S. Geological Survey (USGS) and provides average land use values for albedo, Bowen ratio, and surface roughness within a specified radius. While current air modeling guidance suggests that the land use parameters selected for a modeling analysis be based on the data measurement site (i.e., SAV), EPA also requests that applicants for PSD air permits demonstrate that the land use parameters collected at an airport site are representative of the land use parameters at their project site.

In January 2008, EPA released recommendations for determining the land use characteristics of an area in its AERMOD Implementation Guide. The Guide, which was updated in March 2009, recommends the following procedures:

- Surface roughness length should be based on an inverse-distance weighted geometric mean for the default upwind distance of 1 km relative to the measurement site
- The Bowen ratio should be based on a simple, unweighted geometric mean over a default 10-km by 10-km domain. There should be no direction or distance dependency for the data
- The albedo should be based on a simple unweighted arithmetic mean for the same domain used for the Bowen ratio

Georgia EPD used AERSURFACE Version 08009 (EPA, January 9, 2008) to calculate the land use characteristics for both SAV and the Project site. The average parameter values calculated for each site are as follows:

Average land use around SAV:

- Albedo – 0.15
- Bowen ratio – 0.515 (average moisture)
- Surface roughness – 0.057 m

Average land use around the Project site:

- Albedo – 0.14
- Bowen ratio – 0.453 (average moisture)
- Surface roughness – 0.728 m

While the average albedo and Bowen Ratios for the two land use areas are essentially identical, the average surface roughness value of the two sites is quite different. The large difference in average surface roughness is common and is due to the obstruction-free cleared areas (i.e., mostly grass and pavement) that typically exist within 1km of an airport's meteorological tower. Since significant differences in the surface roughness values input to AERMOD have been known to result in large variations in the maximum predicted impacts, the SAV meteorological record was processed with the Project site land use parameters and additional modeling was performed to determine which meteorological data set (i.e., SAV versus Project site albedo, Bowen Ratio and surface roughness) produces the higher air impacts. Using the Project site coordinates, Georgia EPD re-processed the SAV meteorological data record with the Project site's land use values. The Project-only emissions were then modeled using both meteorological data sets and the results of this comparative analysis is presented in Section 6.11.

The results indicated that use of the Project site's land use parameters in the air modeling analysis resulted in predicted air quality impacts that were greater than those predicted using the SAV land use parameters. As such, the meteorological data with land use values from the Project site were selected to be used throughout the modeling analysis.

6.6 Emission Inventory

6.6.1 Significant Impact Analysis

Summaries of the pollutant emission rates, physical stack and stack operating parameters for the Project that were used in the air modeling analysis are presented in Tables 2-1 through 2-7 as well as Appendix A.

In an effort to obtain the maximum air quality impacts for a range of possible combustion turbine operating conditions, the air modeling analysis initially evaluated the air impacts for a range of CT emission rates and CT stack parameter data. The emission and stack operating parameters for the CTs are presented for three operating loads and 20°F, 59°F, and 95°F ambient temperatures for the CTs firing natural gas and ultra low sulfur fuel oil. A total of 10 modeling scenarios were considered for the combined cycle configuration with the CTs operating for the following conditions:

CTs firing natural gas for ambient temperatures of 20, 59, and 95°F at:

- 100 percent operating load with duct-firing
- 100 percent operating load with duct-firing with inlet chiller on
- 70 percent operating load
- 50 percent operating load

CTs firing ultra low sulfur fuel oil for ambient temperatures of 20, 59, and 95°F at:

- 100 percent operating load with duct-firing
- 70 percent operating load
- 50 percent operating load

To determine the operating load that produced the maximum impacts from the CTs, an emission rate of 10 grams per second (g/s) was used for the two CTs, with each CT modeled with 5 g/s. These modeling results produced relative concentrations as a function of the modeled emission rate. These impacts are referred to as generic pollutant impacts. Maximum air quality impacts for specific pollutants were then determined by multiplying the maximum pollutant-specific emission rate by the maximum predicted generic impact divided by the modeled emission rate of 10.0 g/s.

Pollutant-specific significant impact analyses were performed for NO_x, PM₁₀, PM_{2.5}, and CO emissions to address the combined impact of the CTs and the other Project sources.

For averaging times of 24-hours or less, NO_x and CO emissions under startup emissions are much greater than those occurring during normal CT operation. As such, startup conditions were the critical operating conditions used for the short-term NO₂ and CO significant impact analyses. Therefore, for NO_x

and CO impacts, the analysis included the CTs maximum emissions during startup conditions, the fuel gas heater and auxiliary boiler.

For the annual average NO₂ significant impact analysis, the CT operation firing natural gas and fuel oil that resulted in the highest annual NO_x emissions at base load and 59°F ambient temperature and accounting for warm starts, cold starts, shutdown, and downtime (see Table 2-3) was modeled.

Because the CT PM₁₀ and PM_{2.5} emissions are much greater for normal operation than for startup and shutdown conditions, the worst-case CT load and ambient temperature during normal CT operating conditions were used for the PM₁₀ and PM_{2.5} significant impact analyses. Therefore, for PM₁₀ and PM_{2.5}, the significant impact analysis included the CTs at their worst-case load and temperature under normal operation in addition to the fuel gas heater, auxiliary boiler and the cooling tower. Detailed descriptions of these sources are presented in Section 2.0 and Appendix A.

The proposed CTs will have a HRSG stack height of 165 ft and an inner stack diameter of 19.0 ft. Because the proposed stack heights are less than Good Engineering Practice (GEP), building downwash effects were included in the modeling analysis (see following section on building downwash). Building downwash effects were also included for the other sources, as appropriate.

For this modeling, an approximate facility modeling origin was assumed to be located at UTM East and North coordinates of 473,300 and 3,571,400 meters, respectively, in UTM Zone 17, datum NAD83.

6.6.2 AAQS and PSD Class II Analyses

The maximum impacts for the Project are predicted to be greater than the presumed SIL for only the 1-hour NO₂ and 24-hour average PM_{2.5} concentrations. As a result, cumulative source impact analyses were required to determine compliance with the 1-hour NO₂ and 24-hour PM_{2.5} NAAQS. Because PSD increments for these pollutants have not yet been promulgated, PSD Class II increment analyses are not required.

The significant impact area (SIA) for each pollutant was determined based on the maximum distance to which each pollutant had a predicted significant impact. The maximum radius of impact was used as the basis for determining the inventory of background sources to be included in the air impact analyses.

The Project's SIAs for the 1-hour NO₂ and 24-hour PM_{2.5} impacts are predicted to extend out to 4.2 and 1.7 km from the Project site, respectively. EPA and Georgia EPD modeling guidance require that the background source inventory include sources located within and 50 km beyond the SIA.

Facilities located within the SIA (i.e., referred to as the modeling area) were included in the modeling analysis. Facilities located beyond the SIA but within the SIA plus 50 km were considered to be in the screening area. The Georgia EPD provided a list of Title V facilities and modeling files from other recent analyses that included source emissions and stack parameter data for nearby background facilities.

The locations of the existing Effingham County Power Plant sources were obtained from a current site plan. The existing Effingham CTs are assumed to be identical to the proposed CTs except the existing CTs fire natural gas only and do not have duct burners. As a conservative approach, the modeled emissions and stack operating parameters for the existing CTs were based on the proposed CTs operation based on the operation that produced maximum impacts. This is a conservative approach since the proposed CTs' NO₂ impacts were highest for startup conditions while the PM_{2.5} impacts were highest when CTs were operating at 50 percent load and firing fuel oil. The existing CTs are highly unlikely to operate for those conditions simultaneously as the proposed CTs.

Similarly, the emissions and stack parameters data for the existing plant's auxiliary equipment are assumed to be the same as those for the Project. Lastly, maximum NO_x emissions and stack parameters for the Georgia-Pacific's (GP) Savannah River Mill were obtained from GP. GP also identified that the GP Savannah Mill in Chatham County has shutdown.

Because the screening area for the Project also extended into four South Carolina counties, the South Carolina Department of Health and Environmental Control (SCDHEC) was contacted for a list of sources in those counties.

In order to evaluate sources in the screening area that could significantly interact with the Project, facilities in the screening area were evaluated using the North Carolina screening technique (also known as the "20D approach"). Based on this technique, facilities whose annual emissions (i.e., TPY) are less than the threshold quantity, Q, are eliminated from the modeling analysis since they are not likely to significantly interact with the Project. Q is equal to $20 \times (D - \text{SIA})$, where D is the distance in km from the facility to the Project site.

Before facilities were eliminated based on the 20D approach, facilities in the screening area were sorted by direction and distance to review the proximity of the facilities to one another. Facilities that were located within approximately 3 degrees of one another direction-wise, and within approximately 3 km of one another distance-wise, were grouped together into a cluster. Potential emissions from the cluster of sources were then summed and compared to the threshold quantity Q based on the facility nearest to the Project that was within the cluster. Finally, facilities located beyond the screening area were evaluated for inclusion in the modeling analysis based on the Q and cluster approach.

A summary of background facilities for which NO_x emissions were evaluated for inclusion in the AAQS and their direction and distances from the Project is shown in Table 6-2. Facilities whose emissions were combined and included in a cluster because of their proximity to one another are shown in Table 6-2. The last column of Table 6-2 indicates the background sources that were included in the modeling analysis. A summary of the detailed source emissions and parameter data included in the NO_2 NAAQS analyses is presented in Table D-1.

Similarly, a summary of background facilities for which $\text{PM}_{2.5}$ emissions were evaluated for inclusion in the AAQS and their direction and distances from the Project is shown in Table 6-3. The last column of Table 6-3 indicates the background sources that were included in the modeling analysis. A summary of the detailed source emissions and parameter data included in the $\text{PM}_{2.5}$ NAAQS analyses is presented in Table D-2. For these analyses, it was assumed that the PM emissions for each source are $\text{PM}_{2.5}$ emissions.

Detailed NO_x and $\text{PM}_{2.5}$ emission calculations for certain modeled sources, based on air permit applications or information available from a facility are presented in Table D-3.

6.6.3 PSD Class I Analysis

Since the maximum annual average NO_2 and PM_{10} impacts due to the Project were predicted to be less than EPA's Class I SIL, additional detailed modeling to demonstrate compliance with the allowable PSD Class I increments is not required.

6.7 Building Downwash Effects

The stacks for the Project's sources were evaluated for determining compliance with GEP regulations and the potential influence of nearby buildings and structures that could cause aerodynamic building downwash. For each stack that is below the GEP height, direction-specific building heights and maximum projected widths were determined using the Building Profile Input Program (BPIP, Version 04274) which incorporates the Plume Rise Model Enhancement (PRIME) downwash algorithm developed by EPRI. Direction-specific building information output by BPIP was input to AERMOD for processing.

The AERMOD model addresses the effects of aerodynamic downwash by utilizing downwash algorithms based on stack and building locations and heights which are input to the model. Proposed structures at the Project site were identified from a site plan. Building dimensions for the structures were entered into BPIP for the purpose of developing wind direction-specific building dimensions for input to AERMOD. The summary of the existing and proposed Effingham County Power Plant structure dimensions is presented in Table 6-4.

6.8 Receptor Locations

6.8.1 Site Vicinity

For the significant impact analysis, a Cartesian receptor grid was used. Receptors were located at the following intervals and distances:

- Every 50 m along the Project's fenceline
- Every 100 m from the fenceline to 2,000 m
- Every 250 m from 2,000 to 4,000 m
- Every 500 m from 4,000 to 7,000 m
- Every 1,000 m beyond 7,000 m, out to 20 km, to determine the significant impact distance

The heights above mean sea level (msl) for all receptors were extracted from 1-second National Elevation Dataset (NED) data obtained from the USGS' seamless server. The NED data were extracted for all sources and receptors using AERMOD's terrain preprocessing program AERMAP, Version 09040.

Based on the results of the significant impact analyses, receptor grids used in determining compliance with the 1-hour NO_2 and 24-hour $\text{PM}_{2.5}$ NAAQS extended out to 4.5 km and 2.0 km, respectively.

6.8.2 PSD Class I Areas

An array of receptors located 50 km from the Project site was developed for input to AERMOD. The receptors were based on the directions of each PSD Class I area that is located within 300 km of the Project. The following direction range and elevation representing each PSD Class I area were determined as follows:

- Cape Romain NWA: 1-degree intervals from 62 to 65 degrees with an elevation and hill scale of 2 m (i.e., highest elevation of PSD Class I area)
- Wolf Island NWA: 1-degree intervals from 180 to 183 degrees with an elevation and hill scale of 3 m (i.e., highest elevation of PSD Class I area)
- Okefenokee NWA: 1-degree intervals from 204 to 218 degrees with an elevation and hill scale of 27 m (i.e., lowest elevation of PSD Class I area)

All receptors are in UTM coordinates from Zone 17, NAD83.

6.9 Background Concentrations

As previously discussed, representative background concentrations are added to the modeled impacts to determine total air quality impacts. The total impacts are then compared to determine compliance with the appropriate NAAQS. By definition, "background" includes other point sources (i.e., distant sources or small sources), non-project related fugitive emission sources, and natural background sources not included in the modeling analysis.

Ambient background concentration for the 1-Hour NO₂ was provided by the Georgia EPD based on their review of the monitoring data available to represent background for the Project site.

For PM_{2.5}, the ambient 24-hour background concentration of approximately 25 µg/m³ was based on the average of the 98th percentile of 24-hour concentrations measured for the latest data available from the following sites:

LOCATION	YEAR	PM _{2.5} MEASUREMENTS – 98 TH PERCENTILE, 24-HOUR AVERAGE (µg/m ³)
Georgia EPD Savannah Lathrop Monitor	2009 2008	20.6 25.2
EPA Monitor ID 13-051-0017 402 Market Street Savannah, Georgia	2008 2007	24.5 27.0
EPA Monitor ID 13-051-0091 Mercer Jr. High School, Garden City, Savannah, Georgia	2008 2007	20.1 30.5

The 1-hour average NO₂ and 24-hour average PM_{2.5} concentrations used to represent the background concentrations are 40 and 25 µg/m³, respectively. These concentrations were added to the modeled source concentrations to obtain total air quality concentrations that were compared to the NAAQS.

6.10 NO₂ Modeling Approach

Golder has requested approval from EPA to use the Plume Volume Molar Ratio Method (PVMRM) option of AERMOD for the determination of NO₂ concentrations as part of the air quality analysis for the Project. The use of PVMRM is a more detailed analysis than the EPA recommended approach of applying the NO₂/NO_x factor of 75 percent as described below.

Demonstrations showing short-term NO₂ NAAQS compliance are required for a project that undergoes PSD review if the project does not have a complete permit by April 12, 2010. Previously, air quality impact assessments for PSD application need only address the annual average NO₂ NAAQS which typically did not require a more detailed screening approach, such as the use of PVMRM.

Golder has requested to use PVMRM for predicting the NO₂ concentrations based on the following reasons:

- EPA's Guideline on Air Quality Models (GAQM) (Appendix W, 40 CFR 51, July 2009) recommends the use of a multi-tiered approach to estimate NO₂ concentration

- PVMRM is already implemented in AERMOD which is approved by EPA for assessing impacts within 50 km from a source
- Based on studies and the science, the PVMRM chemistry appears to be more realistic in treating the conversion of NO to NO₂ and limiting the conversion as it considers the situation within the plume itself
- PVMRM has been approved for use by EPA in the state of Alaska and is used in the air modeling community outside of the U.S.

As indicated, GAQM recommends a multi-tiered screening approach for estimating annual NO₂ concentrations, where:

- Tier 1 assumes full conversion of NO_x to NO₂
- Tier 2 assumes a 75 percent ambient equilibrium ratio of NO₂ to NO_x
- Tier 3 allows detailed screening techniques on a case-by-case basis

In general, maximum NO₂ concentrations estimated using Tier 1 (total conversion) or Tier 2 (default equilibrium NO₂/NO_x ratio of 0.75) provide conservative estimates of NO₂ concentrations when assessing compliance with the annual standard of 100 µg/m³. For stationary sources with NO_x emission controls, such as the current project, the NO₂ impacts are predicted to be well below the annual AAQS and, in many cases, less than the annual significant impact level. However, for the 1-hour average concentrations which are greatly affected by the widely varying meteorological conditions, modeling of the emission sources, such as those for this project, can show 1-hour average NO₂ concentrations to be high relative to the 1-hour AAQS of 188 µg/m³ using the Tier 1 or the Tier 2 approach. There is a clear need to perform a more detailed screening analysis, using less conservative assumptions and more realistic methods to account for NO₂ formation when assessing NO₂ concentrations from a source, such as the PVMRM method.

PVMRM is discussed in the Section 5.1, Appendix W, and was being tested to determine its suitability as a refined method when the GAQM was last updated in 2005. Since that time, the PVMRM algorithm has been implemented into AERMOD and is currently available in the most recent version of the model (Version 09292) as a “non-default” option. The addendum to the AERMOD User’s Guide dated October, 2009 provides the usage instructions for PVMRM.

Two detailed methods for assessing NO₂ concentrations are PVMRM and Ozone Limiting Method (OLM), also discussed in the GAQM. Both PVMRM and OLM are ambient ozone-based algorithms that limit the conversion of nitric oxide (NO) to NO₂ based on available ambient ozone. The PVMRM uses the same chemistry and ozone concentration data as OLM but also accounts for plume size to derive the amount of ozone available within the plume for the reaction between NO and ozone. In contrast, the OLM does not account for the plume size or in-plume concentrations. For a given NO_x emission rate and ambient ozone

concentration, PVMRM controls the conversion of NO to NO₂ based on NO_x concentrations within the volume of the plume in contrast to OLM, which controls the conversion based on ground-level NO_x concentrations.

Because of the reasons above and additional support material, EPA Region X approved the use of the PVMRM option in 2006 for ambient air quality analyses prepared for the State of Alaska. The additional support material provided to the Alaska Department of Environmental Conservation (ADEC) included a sensitivity analysis using OLM and PVMRM options in AERMOD performed in September, 2004, and an evaluation of bias using PVMRM option in AERMOD performed in June, 2005. Both of these studies helped EPA Region 10 to determine that the non-default PVMRM option in AERMOD is an acceptable technique to predict NO₂ concentration impacts from combustion sources emitting NO_x through a stack and results in unbiased concentration impacts. As a result of this determination, EPA Region 10 approved the PVMRM option for application in Alaska. The PVMRM method was most recently used for the Exxon Mobil Corporation's Point Thomson Drilling Operations air permit application (ADEC Technical Analysis Report for Permit AQ1201MSS01, April 2010).

The PVMRM method is also the recommended method to be used for predicting NO₂ concentrations elsewhere, such as in Alberta, Canada (Air Quality Modeling Guidelines, Government of Alberta).

For the NAAQS analyses, an initial NO₂ concentration equivalent to 10 percent of NO_x at the stack and an equilibrium NO₂ to NO_x ratio of 0.9 in the plume, which are the current default values per the AERMOD User's Guide, were used. Golder obtained hourly ozone monitoring data available from the area monitors and used the highest value of 83 ppb as a constant value throughout the year (see Section 5).

Appendix C presents the request to EPA to use the PVMRM to address the predicted NO₂ impacts for this Project.

6.11 Toxic Air Pollutant Analysis

Air quality impacts for toxic air pollutants emitted by the Project were assessed by following the Georgia EPD procedures in the *Guideline for Ambient Impact Assessment of Toxic Air Pollutant Emissions* (Toxics Guidelines) (Georgia EPD, 1998). Although the Industrial Source Complex Short-Term (ISCST3) is identified as the recommended model to evaluate toxic air impacts, AERMOD was used to provide maximum concentrations since this model was used in evaluating the Project's concentrations for comparison to NAAQS. The Project concentrations were then compared to the Acceptable Ambient Concentrations (ACC) developed from procedures in the guideline.

The AAC were generally based on information from the Integrated Risk Information System (IRIS). The information is presented as unit risk given as a risk per concentration ($\mu\text{g}/\text{m}^3$)⁻¹ and/or an inhalation reference concentration (RfC) in units of milligrams per cubic meter (mg/m^3). Unit risk estimates are

estimated from the risk-based air concentrations (RBACs) that provide a cancer risk of 1 in 1,000,000 for pollutants with an IRIS weight-of-evidence classification of A; 1 in 100,000 with a classification of B; and 1 in 10,000 with a classification of C. The RBAC is calculated by dividing the cancer risk by the unit risk. Both the RfC and RBAC are given as an annual average.

For those pollutants that have a RBAC or RfC as well as a ceiling limit or short-term exposure limit (STEL), both an annual and 15-minute AAC were estimated. The annual AAC was estimated from the RBAC or RfC and a 15-minute AAC was estimated from the ceiling limit of STEL. The ceiling limits or STEL were obtained from exposure limits recommended by the American Conference of Government Industrial Hygienists (ACGIH). If a pollutant did not have a RBAC or RfC, then the 24-hour and 15-minute AAC were estimated from the 8-hour time-weighted average (TWA) and ceiling limit or STEL. The 8-hour TWA is assumed to be equal to the 24-hour AAC.

The exposure toxicity data (TA) acquired from TWAs, STELs, or ceiling limits is adjusted by application of a safety factor. The safety factor accounts for pollutant exposure to members of the public who may be more sensitive to pollutant effects (persons with respiratory maladies, young children, or the elderly) than the average citizen. The recommended formula for application of the safety factor is:

$$\text{AAC} = \text{TA} \div \text{safety factor}$$

The safety factor recommended adjusting TWAs for a pollutant, which are not known human carcinogens, is 100. For known human carcinogens, the recommended safety factor for adjusting TWAs is 300. The safety factor recommended for an acute sensory irritant (those pollutants with ceiling limits or STELs) is 10. The AACs are presented in Table 6-5.

It should be noted that the 15-minute average concentrations were obtained by multiplying the 1-hour average concentrations by a factor of 1.32 based on methods presented in the Georgia EPD's guideline document.

6.12 Model Results

6.12.1 Significant Impact Analysis in the Site Vicinity

The CT load analysis results are summarized in Tables 6-6 and 6-7 for natural gas-firing and fuel oil-firing. A summary of the maximum pollutant impacts for the CT load analysis is shown in Table 6-8. The critical loads presented in these tables are for normal CT operation and were used for subsequent modeling analyses only for PM₁₀ and PM_{2.5} because the maximum CT NO_x and CO emissions occur during cold start-up conditions. The results presented in the tables are based on using SAV and Project land uses in order to identify the worst-case operating load.

The Project's maximum concentrations are summarized in Table 6-9 for comparison to the EPA Class II significant impact levels. Results are presented using the SAV and CLS meteorological data for both the SAV and Project's land use characteristics. Based on the results, the Project impacts are predicted to be higher using the Project site land use meteorological record. Therefore, the remainder of the air impact assessment for addressing compliance with NAAQS was based on the Project site land use meteorological record.

The maximum pollutant impacts for the Project are predicted to be less than the SIL for PM₁₀ (annual and 24-hour averages), CO (1- and 8-hour averages), annual average PM_{2.5}, and annual average NO₂ concentrations. For the purpose of predicting significant impact, the maximum predicted annual and 1-hour NO₂ concentrations are based on applying the EPA recommended NO₂/NO_x factor of 75 percent. The maximum pollutant impacts for the Project are predicted to be greater than the presumed SIL for only the 1-hour NO₂ and 24-hour PM_{2.5} concentrations. As a result of the significant impact analysis, cumulative source impact analyses are required for the Project to demonstrate compliance with the 1-hour NO₂ and 24-hour PM_{2.5} NAAQS.

6.12.2 Significant Impact Analysis at PSD Class I Areas

The Project's maximum NO₂ and PM₁₀ concentrations predicted in the screening grid to represent the PSD Class I areas are summarized in Table 6-10 and are compared to the proposed PSD Class I SIL. The maximum predicted NO₂ concentrations are based on applying the EPA recommended NO₂/NO_x factor of 75 percent.

The maximum pollutant impacts for the Project at the PSD Class I areas are predicted to be less than the SIL for all pollutants and averaging times. As a result, the Project impacts are predicted to be less than the SIL at the PSD Class I areas and additional modeling to demonstrate compliance with the PSD Class I increments is not required.

6.12.3 NAAQS Analyses

A summary of the results of the 1-hour NO₂ and 24-hour PM_{2.5} analyses is presented in Table 6-11. The highest 5-year average of the maximum predicted 24-hour PM_{2.5} concentration is 5.3 µg/m³ which, when added to a non-modeled background concentration of 25 µg/m³, provides a total 24-hour PM_{2.5} concentration of 30 µg/m³ which is less than the NAAQS of 35 µg/m³.

For NO₂ concentrations, the maximum results are presented using the 75 percent NO₂/NO_x ratio and PVMRM. Using the 75 percent NO₂/NO_x ratio, the highest 5-year average of the maximum predicted 8th-highest 1-hour NO₂ concentration is 67.8 µg/m³ which, when added to a non-modeled background concentration of 40 µg/m³, provides a total 1-hour NO₂ concentration of 108 µg/m³ which is less than the NAAQS of 188 µg/m³.

Using the PVMRM method, the highest 5-year average of the maximum predicted 8th-highest 1-hour NO₂ concentration is 56.8 µg/m³ which, when added to a non-modeled background concentration of 40 µg/m³, provides a total 1-hour NO₂ concentration of 97 µg/m³ which is less than the NAAQS of 188 µg/m³.

6.12.4 Air Toxics Analysis

A summary of the Project's maximum concentration of toxic air pollutants is presented in Table 6-12. These maximum concentrations for the Project are predicted to be well below the AAC levels. As a result, the Project will comply with the AAC and not have an adverse effect on public health.

6.12.5 Conclusions

Based on the air impact analyses conducted in support of the PSD construction application for the proposed Effingham County Power Plant Expansion Project, the maximum pollutant concentrations due to the Project only are predicted to be less than the PSD Class II SIL for applicable pollutants except the SIL for the 1-hour NO₂ and 24-hour PM_{2.5} concentrations. As a result, additional modeling analyses with background sources were performed to estimate the 1-hour NO₂ and 24-hour PM_{2.5} concentrations to address compliance with the 1-hour NO₂ and 24-hour PM_{2.5} NAAQS. Based on the analyses, the Project is expected to comply with the NO₂ and PM_{2.5} NAAQS.

Based on the PSD Class I significant impact analysis, the maximum pollutant concentrations due to the Project are predicted to be less than the PSD Class I SIL for all pollutants and that further modeling was not required.

Based on the toxic air pollutant analysis for the Project sources, the Project is in full compliance with Georgia EPD air toxic requirements.

The results of the air modeling analyses demonstrate that the Project will comply with all applicable NAAQS and will not have a significant adverse effect on human health and welfare.

7.0 ADDITIONAL IMPACT ANALYSIS

This section presents the impacts that the Project will have on associated growth; impacts to vegetation, soils, and visibility in the vicinity of the existing Effingham Power Plant site; and impacts at the PSD Class I areas within 300 km of the Plant related to AQRVs.

7.1 Impacts Due to Direct Growth

The proposed expansion Project at the existing Effingham Power Plant is needed to meet current and projected electric demands for Mackinaw Power's customers. The Plant is located in a predominantly rural area with limited number of facilities located within a 10-km radius. Additional industrial, commercial, or residential growth as a direct result of the additional electric power provided by the Project is not expected.

Construction of the Project will occur over a period of approximately 24-months requiring construction workers commuting to the Plant. There will be an increase of vehicular traffic on the access road to the Plant due to the movement of commute and construction vehicles. However, this will be a temporary increase lasting for the duration of the construction period. The access road to the plant is paved, so the potential increase in fugitive emissions generated due to the additional traffic will be small. During operation, less than five additional workers will be needed to operate the proposed new Power Block 2. Therefore, there would be a small increase in vehicular traffic to and from the facility during operation. It is therefore expected that the effect of the construction and operation of the proposed Power Block 2 on local air quality levels would be minimal.

It is expected that the additional workforce will reside in Rincon, the nearest city to the Plant. The small number of additional workforce is not expected to account for any significant residential growth in Rincon. The existing commercial infrastructure at Rincon should be adequate to provide any support services that the construction and operation of the Project might require.

7.2 Impact on Soils, Vegetation, Wildlife, and Visibility in the Project's Vicinity

The maximum air quality impacts for the Project predicted in the vicinity of the site were used to assess the Project's potential impacts on nearby soils, vegetation, wildlife, and visibility.

Soils in the vicinity of the Effingham Power Plant consist of three soil series as identified in the U.S. Department of Agriculture (USDA) Soil Survey of Effingham County (2007), Pelham loamy sand, Surrency mucky sand, and Leefield loamy sand. Soils in the county are highly weathered and naturally acidic.

Effingham County is about 77 percent forested. Among the most significant forest types in the County are mixed hardwood/pine, loblolly pine, and longleaf/slash pine. The surrounding vicinity of the Effingham

Plant up to about 1 km is forest. No threatened, endangered, or sensitive plant species are observed within the site vicinity.

Maximum concentrations of criteria pollutants predicted in the vicinity of the Project site were predicted to be below the EPA Class II significant impact levels except for the presumed SIL for the 1-hour NO₂ and 24-hour PM_{2.5} concentrations (see Table 6-9). Based on NAAQS compliance analysis (see Table 6-10), the total air quality impacts due to the Project and background sources will comply with the 1-hour average NO₂ and 24-hour average PM_{2.5} NAAQS. Since the NAAQS are designed to protect the public welfare, including effects on soils and vegetation, no detrimental effects on soils or vegetation should occur in this area.

Although air pollution impacts to wildlife have been reported in the literature, many of the incidents involved acute exposures to pollutants, usually caused by unusual or highly concentrated releases or unique weather conditions. Generally, there are three ways pollutants may affect wildlife: through inhalation, through exposure with skin, and through ingestion. Ingestion is the most common means and can occur through eating or drinking of high concentrations of pollutants. Bioaccumulation is the process of animals collecting and accumulating pollutant levels in their bodies over time. Other animals that prey on these animals would then be ingesting concentrated pollutant levels.

It is unlikely that the Project's emissions will cause injury or death to wildlife based on review of the limited literature on air pollutant effects on wildlife. The Project's impacts are predicted to be very low and dispersed over a large area. Coupled with the mobility of wildlife, the potential for exposure of wildlife to the Project's impacts under weather conditions that lead to high concentrations is extremely unlikely.

Visibility impairment in the Project's vicinity is not expected due to the types and quantities of emissions proposed for the Project. The opacity of the proposed CT exhaust emissions will be 10 percent or less.

Visibility impairment due to the cooling tower is expected to be minimal. The plume from the cooling tower is expected to be visible within about 300 ft of the cooling tower for majority of the time. For certain directions, the plume may be visible out to 1,000 ft on an infrequent basis. Because of the limited distance that the cooling tower plume would be visible, the plume is not expected to affect visibility on local roadways or airports. SAV, the nearest public airport is approximately 17 km away. Due to the expected low frequency of occurrence of the visible plume, the effect on local meteorology is also expected to be insignificant. Localized, temporary, ground-level fogging may also occur infrequently during plume downwash conditions. This locally induced fog would dissipate rapidly due to the high winds associated with plume downwash conditions.

7.3 Impacts Upon PSD Class I Areas

The Project is located about 101, 162, and 167 km from the PSD Class I areas of Wolf Island NWA, Okefenokee NWAs, and Cape Romain NWA, respectively. Other PSD Class I areas are located more than 200 km from the Project.

As discussed in Chapter 6, upon review of the proposed Project's maximum annual emissions and distance from the PSD Class I areas, the FLM for the PSD Class I areas, the USFWS, notified Georgia EPD that the Project is not considered to pose any significant additional impact at the PSD Class I areas. As such, the proposed Project's impact on AQRV of visibility impairment and acid deposition are not addressed at the PSD Class I areas of visibility impairment and acid deposition since the FLM did not request that AQRV analyses be performed.

REFERENCES

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- Kawasaki Heavy Industries, Ltd. (KHI) 2008. Product Brochure, Kawasaki Gas Turbine Generator Sets, www.khi.co.jp (accessed in September 2008).
- Fuel Tech Inc. (FTEK). 2008a. Product Brochure, NOxOUT NO_x Reduction Process. www.ftek.com (accessed in September 2008).
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- Institute of Clean Air Companies (ICAC). 2006. Typical Installation Timelines for NO_x Emissions Control Technologies on Industrial Sources, December 2006.
- U.S. Environmental Protection Agency (EPA), (2003). Document No. EPA-452/F-03-019: Air Pollution Control Technology Fact Sheet – Selective Catalytic Reduction (SCR), p. 2.

TABLES

TABLE 1-1
SUMMARY OF MAXIMUM ANNUAL POLLUTANT EMISSIONS FOR THE
EFFINGHAM POWER EXPANSION PROJECT, EFFINGHAM COUNTY, GEORGIA

Pollutant ^a	Maximum Project Emissions ^b (TPY)
Sulfur Dioxide (SO ₂)	25.3
Total Particulate Matter (PM)	112.3
Particulate Matter <10 microns (PM ₁₀)	111.4
Fine Particulate Matter (PM _{2.5})	108.7
Nitrogen Oxides (NO _x)	282.3
Carbon Monoxide (CO)	537.1
Volatile Organic Compounds (VOC)	46.3
Sulfuric Acid Mist (SAM)	4.5
Lead	0.03

^a Note that PM, PM₁₀, and PM_{2.5} emissions are not additive.

^b Based on the Project operating in combined cycle mode with two combustion turbines (CTs) at baseload conditions firing natural gas at 59 degrees Fahrenheit (°F) ambient temperature. Project emissions estimates include the following units and operating hours:

CT-Only Operation firing Natural Gas -	1,601 hours
CT +DB Operation -	4,000 hours
CT Operation firing Fuel Oil -	1,000 hours
Cold Startup -	50 hours (10 events)
Warm Startup -	749 hours (290 events)
Shutdown -	300 hours (300 events)
CT Downtime -	1,060 hours
10-Cell Mechanical Draft Cooling Tower -	8,760 hours
Inlet Chiller Cooling Tower -	8,760 hours
Natural Gas Heater -	8,760 hours
Auxiliary Boiler -	2,500 hours

Source: Mackinaw Power, 2010; Golder, 2010.

TABLE 2-1
STACK, OPERATING, AND EMISSIONS DATA FOR THE COMBUSTION TURBINES AND DUCT BURNERS
NATURAL GAS COMBUSTION
EFFINGHAM PLANT EXPANSION PROJECT

Parameter		Operating and Emission Data ^a for Ambient Temperature													
		CT/HRSG - Baseload				CT/HRSG & Duct Burner - Baseload				CT/HRSG - 75% Load			CT/HRSG - 50% Load		
		20 °F	59 °F	95 °F	95 °F	20 °F	59 °F	95 °F	95 °F	20 °F	59 °F	95 °F	20 °F	59 °F	95 °F
		Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7	Case 8	Case 9	Case 10	Case 11	Case 12	Case 13	Case 14
Stack Data (ft)															
Height	ft	165	165	165	165	165	165	165	165	165	165	165	165	165	165
Diameter	ft	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0
100 Percent Load															
Operating Data															
Temperature	°F	203.0	202.0	201.0	202.0	203.0	202.0	201.0	202.0	202.7	203.7	204.7	175.3	177.5	182.2
Velocity	ft/sec	65.4	60.9	55.8	60.9	65.9	61.3	56.2	61.2	49.3	49.1	46.5	39.9	39.0	37.8
Heat Input	MMBtu/hr (HHV)	1,995.0	1,858.5	1,690.5	1,858.5	2,465.0	2,328.5	2,160.5	2,328.5	1,638.0	1,512.0	1,396.5	1,292.6	1,212.8	1,115.1
Maximum Hourly Emissions per CT/HRSG (lb/hr)															
SO ₂	lb/hr	2.7	2.5	2.3	2.5	3.4	3.2	2.9	3.2	2.2	2.1	1.9	1.8	1.7	1.5
PM/PM ₁₀ /PM _{2.5} ^b	lb/hr	9.7	9.7	9.6	9.7	13.6	13.5	13.5	13.5	9.6	9.5	9.5	9.5	9.4	9.4
NO _x	lb/hr	18.4	17.1	15.6	17.1	28.8	27.6	26.0	27.6	15.1	13.9	12.9	11.9	11.2	10.3
CO	lb/hr	13.4	12.5	11.4	12.5	52.9	52.0	50.8	52.0	11.0	10.2	9.4	8.7	8.2	7.5
VOC (as methane)	lb/hr	3.6	3.3	3.0	3.3	6.2	5.9	5.6	5.9	4.2	3.9	3.6	3.3	3.1	2.9
Sulfuric Acid Mist	lb/hr	0.5	0.5	0.4	0.5	0.6	0.5	0.5	0.5	0.4	0.4	0.4	0.3	0.3	0.3
Maximum Hourly Emissions per CT/HRSG (lb/MMBtu)															
SO ₂	lb/MMBtu	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014
PM/PM ₁₀ /PM _{2.5} ^b	lb/MMBtu	0.0049	0.0052	0.0057	0.0052	0.0055	0.0058	0.0062	0.0058	0.0059	0.0063	0.0068	0.0073	0.0078	0.0084
NO _x	lb/MMBtu	0.0092	0.0092	0.0092	0.0092	0.0117	0.0118	0.0120	0.0118	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092
CO	lb/MMBtu	0.0067	0.0067	0.0067	0.0067	0.0215	0.0223	0.0235	0.0223	0.0067	0.0067	0.0067	0.0067	0.0067	0.0067
VOC (as methane)	lb/MMBtu	0.0018	0.0018	0.0018	0.0018	0.0025	0.0025	0.0026	0.0025	0.0026	0.0026	0.0026	0.0026	0.0026	0.0026
Sulfuric Acid Mist	lb/MMBtu	0.0003	0.0003	0.0003	0.0003	0.0002	0.0002	0.0002	0.0002	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003

^a Refer to Appendix A for detailed information on basis of pollutant emission rates and operating data.
Duct firing is assumed for 100% operating load. No duct firing is assumed for loads less than 100%.

^b Front- and back-half emissions. 100-percent of PM₁₀ is considered to be PM_{2.5}.

Source: Golder Associates, 2010.

TABLE 2-2
STACK, OPERATING, AND EMISSIONS DATA FOR THE COMBUSTION TURBINES AND DUCT BURNERS
FUEL OIL COMBUSTION
EFFINGHAM PLANT EXPANSION PROJECT

Parameter		Operating and Emission Data ^a for Ambient Temperature											
		CT/HRSG - Baseload			CT/HRSG and DB - Baseload			CT/HRSG - 75% Load			CT/HRSG - 50% Load		
		20 °F	59 °F	95 °F	20 °F	59 °F	95 °F	20 °F	59 °F	95 °F	20 °F	59 °F	95 °F
		Case 15	Case 16	Case 17	Case 18	Case 19	Case 20	Case 21	Case 22	Case 23	Case 24	Case 25	Case 26
Stack Data (ft)													
Height	ft	165	165	165	165	165	165	165	165	165	165	165	165
Diameter	ft	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0
100 Percent Load													
Operating Data													
Temperature	°F	297.0	294.8	293.5	297.0	294.8	293.5	271.0	274.0	278.0	256.0	259.0	268.0
Velocity	ft/sec	77.4	71.8	65.3	77.8	72.2	65.7	55.2	53.8	52.2	45.0	44.5	43.4
Heat Input	MMBtu/hr (HHV)	2,085.6	1,962.1	1,768.9	2,085.6	1,962.1	1,768.9	1,707.0	1,602.9	1,457.4	1,320.2	1,251.2	1,138.5
Maximum Hourly Emissions per CT/HRSG (lb/hr)													
SO ₂	lb/hr	3.3	3.1	2.8	3.9	3.7	3.4	2.7	2.5	2.3	2.1	2.0	1.8
PM/PM ₁₀ /PM _{2.5} ^b	lb/hr	17.9	17.8	17.7	18.3	18.3	18.2	17.7	17.7	17.6	17.5	17.5	17.5
NO _x	lb/hr	81.0	76.2	68.7	90.0	85.2	77.7	66.3	62.3	56.6	51.3	48.6	44.2
CO	lb/hr	98.7	92.8	83.7	138.1	132.3	123.2	80.7	75.8	68.9	62.4	59.2	53.9
VOC (as methane)	lb/hr	9.9	9.3	8.4	12.5	11.9	11.0	8.1	7.6	6.9	6.2	5.9	5.4
Sulfuric Acid Mist	lb/hr	0.6	0.6	0.5	0.7	0.6	0.5	0.5	0.5	0.4	0.4	0.4	0.3
Lead	lb/hr	0.029	0.027	0.025	0.029	0.027	0.025	0.024	0.022	0.020	0.018	0.018	0.016
Maximum Hourly Emissions per CT/HRSG (lb/MMBtu)													
SO ₂	lb/MMBtu	0.0016	0.0016	0.0016	0.0019	0.0019	0.0019	0.0016	0.0016	0.0016	0.0016	0.0016	0.0016
PM/PM ₁₀ /PM _{2.5} ^b	lb/MMBtu	0.0086	0.0091	0.0100	0.0088	0.0093	0.0103	0.0104	0.0110	0.0121	0.0133	0.0140	0.0153
NO _x	lb/MMBtu	0.039	0.039	0.039	0.043	0.043	0.044	0.039	0.039	0.039	0.039	0.039	0.039
CO	lb/MMBtu	0.047	0.047	0.047	0.066	0.067	0.070	0.047	0.047	0.047	0.047	0.047	0.047
VOC (as methane)	lb/MMBtu	0.0047	0.0047	0.0047	0.0060	0.0060	0.0062	0.0047	0.0047	0.0047	0.0047	0.0047	0.0047
Sulfuric Acid Mist	lb/MMBtu	0.00031	0.00031	0.00031	0.00032	0.00031	0.00031	0.00031	0.00031	0.00031	0.00031	0.00031	0.00031
Lead	lb/MMBtu	0.000014	0.000014	0.000014	0.000014	0.000014	0.000014	0.000014	0.000014	0.000014	0.000014	0.000014	0.000014

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

Duct firing is assumed for 100% operating load. Duct burner is fired with natural gas only. No duct firing is assumed for loads less than 100%.

^b Front- and back-half emissions. 100-percent of PM₁₀ is considered to be PM_{2.5}.

Source: Golder Associates, 2010.

**TABLE 2-3
STACK, OPERATING, AND EMISSIONS DATA FOR THE COMBUSTION TURBINES DURING STARTUP/SHUTDOWN
EFFINGHAM PLANT EXPANSION PROJECT, EFFINGHAM COUNTY, GEORGIA**

Hour	Heat Input (MMBtu)	Power Output (MW)	Load (%)	Stack Exit Temp F	Stack Exit Flow acfm	Stack Exit Velocity ft/s	Stack Emissions							
							CO (lb)	NOx (lb)	SO ₂ (lb/MMBtu) (lb)		PM ₁₀ (lb/MMBtu) (lb)		VOC (lb/MMBtu) (lb)	
Cold Start														
1.0	543.0	13.1	8.0%	104.9	546,638.8	32.1	234.1	122.3	0.0014	0.7	0.0078	4.2	0.0026	1.4
2.0	568.1	17.1	10.4%	256.3	776,165.4	45.6	208.6	133.6	0.0014	0.8	0.0078	4.4	0.0026	1.5
3.0	589.1	17.5	10.7%	274.3	718,827.2	42.3	164.7	153.3	0.0014	0.8	0.0078	4.6	0.0026	1.5
4.0	865.1	31.7	19.4%	262.6	656,209.4	38.6	660.6	183.1	0.0014	1.2	0.0078	6.7	0.0026	2.2
5.0	1,536.5	112.2	68.5%	229.8	815,326.6	47.9	177.5	127.6	0.0014	2.1	0.0078	11.9	0.0026	3.9
Average Hourly (lb/hr) =							289.1	144.0		1.1		6.4		2.1
Warm Start														
2.58	747.4	39.3	23.7%	237.2	419,737.1	24.7	615.3	174.9	0.0014	1.0	0.0078	5.8	0.0026	1.9
Average Hourly (lb/hr) =							238.2	67.7		0.4		2.3		0.7
Shutdown														
1.0	79.7	2.8	--	184.3	62,431.4	3.7	62.0	14.1	0.0014	0.1	0.0078	0.6	0.0026	0.2

Note: Startup and shutdown emissions rates for NOx and CO and stack parameters are based on actual startup/shutdown data from the existing GE7FA CT/HRSGs at the Effingham Power Plant. SO₂, PM₁₀, and VOC emissions rates are based on 50%-load emissions rates (at 59 F) in lb/MMBtu (see Table 2-1) for the proposed CTs and the actual hourly heat input rate during the startup scenario.

8-Hour Average CO Modeling Emission Rates and Stack Parameters

Hour	Stack Exit Temp		Stack Exit Velocity		Emission Rate	
	F	K	ft/s	m/s	(lb/hr)	(g/s)
1.0	104.9	313.5	32.1	9.8	234.1	29.5
2.0	256.3	397.6	45.6	13.9	208.6	26.3
3.0	274.3	407.6	42.3	12.9	164.7	20.7
4.0	262.6	401.1	38.6	11.8	660.6	83.2
5.0	229.8	382.9	47.9	14.6	177.5	22.4
6.0	201.0	366.9	56.2	17.1	26.0	3.3
7.0	201.0	366.9	56.2	17.1	26.0	3.3
8.0	201.0	366.9	56.2	17.1	26.0	3.3
Average =		375.4		14.3		24.0

Note:

8-Hour average parameters based on cold startup emissions and stack parameters for 5 hours and baseload operation with DB firing for the remaining 3 hours of the 8-hour period. Baseload firing parameters are based on Case 7 in Table 2-1. Average emission rate, stack temperature, and exit velocity used in modeling.

1-Hour Average CO Modeling Emission Rates and Stack Parameters

Hour	Stack Exit Temp		Stack Exit Velocity		Emission Rate	
	F	K	ft/s	m/s	(lb/hr)	(g/s)
1.0	262.6	401.1	38.6	11.8	660.6	83.2

Note:

1-Hour average parameters based on maximum hourly emission rate during the cold startup sequence. Stack temperature and exit velocity are specific to the hour with most emissions.

1-Hour Average NO₂ Modeling Emission Rates and Stack Parameters

Hour	Stack Exit Temp		Stack Exit Velocity		Emission Rate	
	F	K	ft/s	m/s	(lb/hr)	(g/s)
1.0	262.6	401.1	38.6	11.8	183.1	23.1

Note:

1-Hour average parameters based on maximum hourly emission rate during the cold startup sequence. Stack temperature and exit velocity are specific to the hour with most emissions.

Source: Mackinaw Power, 2010; Golder, 2010.

TABLE 2-4
SUMMARY OF MAXIMUM POTENTIAL ANNUAL EMISSIONS FOR THE PROPOSED COMBUSTION TURBINES AND DUCT BURNERS
EFFINGHAM PLANT EXPANSION PROJECT

Pollutant	Fuel: Load: Temp:	Maximum emissions (lb/hr) ^a						Maximum Emissions (tons/year)				
		NG Base 59 °F	NG Base w/DB 59 °F	Oil Base 59 °F	NG Warm start	NG Cold start	NG Shut- down	Operating Scenario	Operating Hours			
									8,760	4,760	3,760	1,601
								CT/ NG Base Load	8,760	4,760	3,760	1,601
								CT/ DB /NG Base Load	0	4,000	4,000	4,000
								CT/ OIL Base Load	0	0	1,000	1,000
								Warm start ^b	0	0	0	749
								Cold start ^b	0	0	0	50
								Shutdown ^b	0	0	0	300
								Downtime ^c	0	0	0	1060
								TOTAL	8,760	8,760	8,760	8,760
<u>One Combustion Turbine</u>												
SO ₂		2.5	3.2	3.1	0.39	1.12	0.11		11.1	12.4	12.6	10.1
PM/PM ₁₀ /PM _{2.5}		9.7	13.5	17.8	2.25	6.38	0.63		42.3	50.1	54.1	44.8
NO _x		17.1	27.6	76.2	67.7	144.0	21.7		74.9	95.8	125.4	139.1
CO		12.5	52.0	92.8	238.2	289.1	62.0		54.7	133.7	173.9	266.1
VOC (as methane)		3.3	5.9	9.3	0.74	2.10	0.21		14.6	19.8	22.7	19.5
Sulfuric Acid Mist		0.5	0.5	0.6	0.08	0.22	0.02		2.2	2.2	2.3	1.8
Lead		0.00	0.00	0.027	0.00	0.00	0.00		0.0	0.0	0.0	0.0
<u>Two Combustion Turbines</u>												
SO ₂		5.1	6.3	6.2	0.8	2.2	0.2		22	25	25	20
PM/PM ₁₀		19.3	27.1	35.6	4.5	12.8	1.3		84.6	100.1	108.3	90
NO _x		34.2	55.1	152	135	288	43		150	192	251	278
CO		25.0	104	185.6	476	578	124		109	267	348	532
VOC (as methane)		6.7	11.8	18.6	1.5	4.2	0.4		29.2	39.5	45.5	39.0
Sulfuric Acid Mist		1.0	1.0	1.2	0.2	0.4	0.0		4.3	4.4	4.5	3.5
Lead		0.00	0.00	0.055	0.000	0.000	0.000		0.000	0.000	0.027	0.027

^a Based on 59 °F ambient inlet air temperature.

<u>Event</u>	<u>min/event</u>	<u>hr/event</u>	<u>No. of events/yr</u>	<u>hr/yr</u>
Warm start	155	2.58	290	749
Cold start	--	5	10	50
Shutdown	--	1	300	300

^c Unit downtime hours are based on a minimum 2 hours of shutdown before a warm start and a minimum of 48 hours shutdown before a cold start.

<u>Event</u>	<u>downtime hr before event</u>	<u>No. of events/yr</u>	<u>downtime hr/yr</u>
Warm start	2	290	580
Cold start	48	10	480
		Total =	1060

Source: Mackinaw Power, 2010, Golder Associates, 2010.



TABLE 2-5
PHYSICAL, PERFORMANCE, AND EMISSIONS DATA FOR THE
MECHANICAL DRAFT COOLING TOWER AND INLET CHILLER COOLING TOWER
EFFINGHAM PLANT EXPANSION PROJECT

Parameter	Units	Mechanical Draft Cooling Tower	Inlet Chiller Cooling Tower
<u>Physical Data</u>			
Number of Cells	--	10	6
Deck Dimensions			
Length	ft	384	36
Width	ft	48	60
Height	ft	33	42
Stack Dimensions			
Height	ft	43	42
Stack Top Effective Inner Diameter per cell	ft	33	21.4
<u>Performance Data</u>			
Discharge Velocity (ft/min)	ft/min	1,877	482
Circulating Water Flow Rate (CWFR) (gal/min)	gal/min	155,000	10,042
Design Hot Water Temperature (°F)	°F	109	109
Design Cold Water Temperature (°F)	°F	89	89
Average Temperature (°F)		99	99
Design Air Flow Rate per cell (acfm)	acfm	1,605,357	173,344
Liquid/Gas (Air Flow) (L/G) Ratio	--	1.15	1.15
Hours of Operation	--	8,760	8,760
<u>Emission Data</u>			
Drift Rate ^b (DR) (percent)	percent	0.001	0.001
Total Dissolved Solids (TDS) Concentration ^c , maximum	ppm	1,000	1,000
Solution Drift ^d (SD)	lb/hr	776	50
PM Emissions ^e	lb/hr	0.78	0.05
	TPY	3.4	0.22
PM ₁₀ Emissions ^f	lb/hr	0.59	0.04
	TPY	2.58	0.17
PM _{2.5} Emissions ^f	lb/hr	0.002	0.0001
	TPY	0.01	0.0007

^a Typical cooling tower design for indicated conditions.

^b Drift rate is the percent of circulating water.

^c Based on existing cooling tower data, Mackinaw Power, 2010.

^d Includes water and based on circulating water flow rate and drift rate (CWFR x DR x 8.34 lb/gal x 60 min/hr).

^e PM calculated based on total dissolved solids and solution drift (TDS x SD).

^f Based on Methodology from Reisman, J. and Frisbie, G., "Calculating Realistic PM10 Emissions from Cooling Towers." See Appendix for Project emissions for calculations.

**TABLE 2-6
PERFORMANCE, STACK PARAMETERS, AND EMISSIONS FOR THE
FUEL GAS HEATER
EFFINGHAM PLANT EXPANSION PROJECT**

Parameter	Units	Value
<u>Performance Data</u> ^a		
Heat Input (HHV)	MMBtu/hr	8.75
Fuel	--	Natural gas
Fuel heating value (HHV)	Btu/ft ³	1,050
Fuel Usage	scf/hr	8,333
Hours per Year	--	8,760
Maximum Fuel Usage	MMscf/yr	73.00
<u>Stack Parameters</u>		
Diameter	ft	2.6
Height	ft	19.2
Temperature	°F	825
Velocity	ft/sec	5.51
Flow	acfm	1,755
<u>Emission Data</u>		
SO ₂ Basis	grains S/100 scf	0.5
Emission Rate	lb/hr	0.012
	TPY	0.052
NO _x Basis ^b	MMBtu/hr	8.75
	lb/MMBtu	0.050
Emission Rate	lb/hr	0.44
	TPY	1.92
CO Basis ^b	MMBtu/hr	8.75
	lb/MMBtu	0.082
Emission Rate	lb/hr	0.72
	TPY	3.14
VOC Basis ^b	lb/10 ⁶ scf	5.5
	lb/MMBtu	0.005
Emission Rate	lb/hr	0.05
	TPY	0.20
PM/PM ₁₀ /PM _{2.5} Basis ^b	lb/10 ⁶ scf	7.6
	lb/MMBtu	0.007
Emission Rate	lb/hr	0.06
	TPY	0.28

^a Mackinaw Power, 2010.

^b AP-42 Tables 1.4-1 and 1.4-2.

**TABLE 2-7
PERFORMANCE, STACK PARAMETERS, AND EMISSIONS FOR THE
AUXILIARY BOILER
EFFINGHAM PLANT EXPANSION PROJECT**

Parameter	Units	Value
<u>Performance Data</u> ^a		
Heat Input (HHV)	MMBtu/hr	17.0
Fuel	--	Natural gas
Fuel heating value (HHV)	Btu/ft ³	1,050
Fuel Usage	scf/hr	16,190
Hours per Year	--	2,500
Maximum Fuel Usage	MMscf/yr	40.48
<u>Stack Parameters</u>		
Diameter	ft	2.6
Height	ft	39.1
Temperature	°F	476
Velocity	ft/sec	18.1
Flow	acfm	5,762
<u>Emission Data</u>		
SO ₂ Basis	grains S/100 scf	0.5
Emission Rate	lb/hr	0.023
	TPY	0.029
NO _x Basis ^b	MMBtu/hr	17
	lb/MMBtu	0.098
Emission Rate	lb/hr	1.67
	TPY	2.08
CO Basis ^b	MMBtu/hr	17
	lb/MMBtu	0.082
Emission Rate	lb/hr	1.39
	TPY	1.74
VOC Basis ^b	lb/10 ⁶ scf	5.5
	lb/MMBtu	0.005
Emission Rate	lb/hr	0.09
	TPY	0.11
PM/PM ₁₀ /PM _{2.5} Basis ^b	lb/10 ⁶ scf	7.6
	lb/MMBtu	0.007
Emission Rate	lb/hr	0.12
	TPY	0.15

^a Mackinaw Power, 2010.

^b AP-42 Tables 1.4-1 and 1.4-2.

TABLE 2-8
SUMMARY OF MAXIMUM POTENTIAL ANNUAL EMISSIONS FOR THE EFFINGHAM EXPANSION PROJECT
EFFINGHAM PLANT EXPANSION PROJECT

Pollutant	Annual Emissions (tons/year)						TOTAL	PSD Significant Emission Rate (tons/year)	PSD Review Required?
	2 CTs/HRSGs with Duct Burners	Mechanical Draft Cooling Tower	Inlet Chiller Cooling Tower	Natural Gas Heater	Auxiliary Boiler	Fuel Oil Tank			
SO ₂	25.3	--	--	0.05	0.03	--	25.3	40	No
PM	108.3	3.4	0.22	0.28	0.15	--	112.3	25	Yes
PM ₁₀	108.3	2.6	0.17	0.28	0.15	--	111.4	15	Yes
PM _{2.5}	108.3	0.01	0.001	0.28	0.15	--	108.7	10 ^a	Yes
NO _x	278.3	--	--	1.92	2.08	--	282.3	40	Yes
CO	532.2	--	--	3.14	1.74	--	537.1	100	Yes
VOC (as methane) (ozone)	45.5	--	--	0.20	0.11	0.49	46.3	40 ^b	Yes
Sulfuric Acid Mist	4.5	--	--	Neg.	Neg.	--	4.5	7	No
Lead	0.03	--	--	Neg.	Neg.	--	0.03	0.6	No

Source: Golder, 2010.

^a Also, 40 TPY of SO₂ or 40 TPY NO_x as precursors.

^b Also, 40 TPY NO_x as precursor.

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

Pollutant	Averaging Time	AAQS ($\mu\text{g}/\text{m}^3$)			PSD Increments ($\mu\text{g}/\text{m}^3$)		Significant Impact Levels ($\mu\text{g}/\text{m}^3$) ^b
		National Primary ^a	National Secondary ^a	Georgia ^a	Class I ^a	Class II ^a	
SO ₂	Annual Arithmetic Mean	80	NA	80	2	20	1
	24-Hour Maximum	365	NA	365	5	91	5
	3-Hour Maximum	NA	1,300	1,300	25	512	25
	1-Hour Maximum ^d	196	NA	NA	NA	NA	NA
PM ₁₀ ^c	Annual Arithmetic Mean	NA	NA	50	4	17	1
	24-Hour Maximum	150	150	150	8	30	5
PM _{2.5} ^c	Annual Arithmetic Mean	15	15	15	NA	NA	NA
	24-Hour Maximum	35	35	35	NA	NA	NA
NO ₂	Annual Arithmetic Mean	100	100	100	2.5	25	1
	1-Hour Maximum ^d	188	NA	NA	NA	NA	NA
CO	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
Ozone ^c	8-Hour Maximum	157	157	157	NA	NA	NA
Lead	Calendar Quarter Arithmetic Mean	1.5	1.5	1.5	NA	NA	NA

Note: Particulate matter (PM₁₀) = particulate matter with aerodynamic diameter less than or equal to 10 micrometers.
 Particulate matter (PM_{2.5}) = particulate matter with aerodynamic diameter less than or equal to 2.5 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 where noted.

^b Maximum concentrations, which if exceeded, may require additional review. Significant impact levels for PM_{2.5} are proposed but not final. Significant impact level for 1-hour average NO₂ is not yet proposed.

^c On July 18, 1997, EPA promulgated revised AAQS for particulate matter and ozone. The ozone standard was modified to be 0.08 ppm (157 $\mu\text{g}/\text{m}^3$); achieved when 3-year average of 4th highest value is 0.08 ppm or less. On October 17, 2006, the PM_{2.5} standards were finalized: 24-hour standard of 35 $\mu\text{g}/\text{m}^3$ (3-year average of 98th percentile) and annual standard of 15 $\mu\text{g}/\text{m}^3$ (3-year average at community monitors). The annual PM₁₀ AAQS was revoked.

^d On February 9, 2010, the 1-hour average NO₂ standard was finalized, which is 100 ppb or 188 $\mu\text{g}/\text{m}^3$ (3-year average 98th percentile). On June 2, 2010, the 1-hour average SO₂ standard was finalized, which is 75 ppb or 196 $\mu\text{g}/\text{m}^3$ (3-year average 99th percentile).

Sources: Federal Register, Vol. 43, No. 118, June 19, 1978.

40 CFR 50; 40 CFR 52.21. GEPA Rules for Air Quality Control, Chapter 391-3-1-.02 (4).



TABLE 3-2
PSD SIGNIFICANT EMISSION RATES AND *DE MINIMIS* MONITORING CONCENTRATIONS

Pollutant	Regulated Under	Significant Emission Rate (TPY)	<i>De Minimis</i> Monitoring Concentration^a (µg/m³)
SO ₂	NAAQS, NSPS	40	13, 24-hour
PM	NSPS	25	10, 24-hour
PM ₁₀	NAAQS	15	10, 24-hour
PM _{2.5}	NAAQS	10	
NO _x	NAAQS, NSPS	40	14, annual
CO	NAAQS, NSPS	100	575, 8-hour
VOC (for O ₃)	NAAQS, NSPS	40	100 TPY ^c
Lead	NAAQS	0.6	0.1, 3-month
SAM	NSPS	7	NM
Total Fluorides	NSPS	3	0.25, 24-hour
Total Reduced Sulfur	NSPS	10	10, 1-hour
Reduced Sulfur Compounds	NSPS	10	10, 1-hour
Hydrogen Sulfide	NSPS	10	0.2, 1-hour
Mercury	NESHAP	0.1	0.25, 24-hour
MWC Organics	NSPS	3.5 x 10 ⁻⁶	NM
MWC Metals	NSPS	15	NM
MWC Acid Gases	NSPS	40	NM
MSW Landfill Gases	NSPS	50	NM

^a Short-term concentrations are not to be exceeded.

^b No *de minimis* concentration; an increase in VOC or NO_x emissions of 100 TPY or more will require monitoring analysis for ozone.

^c Any emission rate of these pollutants.

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

MSW = municipal solid waste

MWC = municipal waste combustor

NAAQS = National Ambient Air Quality Standards

NESHAP = National Emission Standards for Hazardous Air Pollutants

NM = no ambient measurement method established, therefore no *de minimis* concentration has been established.

NSPS = New Source Performance Standards

Source: 40 CFR 52.21

TABLE 3-3
NET INCREASE IN EMISSIONS DUE TO PROPOSED PROJECT COMPARED TO THE
PSD SIGNIFICANT EMISSION RATES
EFFINGHAM POWER EXPANSION PROJECT, EFFINGHAM COUNTY, GEORGIA

Pollutant	Emissions (TPY)		PSD Review Required?
	Project Potential Emissions ^a	Significant Emission Rate	
SO ₂	25.3	40	No
PM	112.3	25	Yes
PM ₁₀	111.4	15	Yes
PM _{2.5}	108.7	10	Yes
NO _x	282.3	40	Yes
CO	537.1	100	Yes
VOC (for O ₃)	46.3	40	Yes
Lead	0.027	0.6	No
SAM	4.5	7	No
Total Fluorides	neg.	3	No
Total Reduced Sulfur	neg.	10	No
Reduced Sulfur Compounds	neg.	10	No
Hydrogen Sulfide	neg.	10	No
Mercury	0.003	0.1	No
MWC Organics (as 2,3,7,8-TCDD)	neg.	3.5 x 10 ⁻⁶	No
MWC Metals (as Be, Cd)	0.012	15	No
MWC Acid Gases (as HCl)	neg.	40	No
MSW Landfill Gases (NMOC)	neg.	50	No

^a Based on the Project operating in combined cycle mode with two combustion turbines (CTs) at baseload conditions firing natural gas at 59 degrees Fahrenheit (°F) ambient temperature. Project emissions estimates include the following units and operating hours:

CT-Only Operation firing Natural Gas - 1,601 hours
 CT +DB Operation - 4,000 hours
 CT Operation firing Fuel Oil - 1,000 hours
 Cold Startup - 50 hours (10 events)
 Warm Startup - 749 hours (290 events)
 Shutdown - 300 hours (300 events)
 CT Downtime - 1,060 hours
 10-Cell Mechanical Draft Cooling Tower - 8,760 hours
 Inlet Chiller Cooling Tower - 8,760 hours
 Natural Gas Heater - 8,760 hours
 Auxiliary Boiler - 2,500 hours

NOTE:

Be = beryllium

Cd = cadmium

HCl = hydrogen chloride

neg. = negligible

NMOC = Non-Methane Organic Compounds

TCDD = tetra- through octa-chlorinated dibenzo-p-dioxans and dibenzofurans

Source: Mackinaw Power, 2010; Golder, 2010.

TABLE 3-4
PREDICTED NET INCREASE IN IMPACTS DUE TO PROPOSED PROJECT
COMPARED TO PSD *DE MINIMIS* MONITORING CONCENTRATIONS
EFFINGHAM POWER PLANT EXPANSION PROJECT, EFFINGHAM COUNTY, GEORGIA

Pollutant	Predicted Net Increase in Impact^a	<i>De Minimis</i> Monitoring Concentration	PSD Monitoring Required?
PM ₁₀	3.02 µg/m ³	10 µg/m ³ , 24-hour	No
NO _x	0.33 µg/m ³	14 µg/m ³ , annual	No
CO	65.8 µg/m ³	575 µg/m ³ , 8-hour	No
O ₃ (as VOC)	46.3 TPY	100 TPY	Yes ^b
O ₃ (as NO _x)	282.3 TPY	100 TPY	Yes ^b

^a See Section 6.0 for air dispersion modeling results.

^b Existing ozone ambient air quality data demonstrate compliance with the AAQS.

Source: Golder, 2010; 40 CFR 52.21.

TABLE 4-1
SUMMARY OF NO_x BACT DETERMINATIONS FOR NATURAL GAS-FIRED CTS (2003-2009)

Facility Name	State	Permit Issued	Process Info	MW/Heat Input	Control Method	NO _x Limit	Basis
<u>Georgia</u>							
Live Oaks Power Project	GA	4/8/2010	(2) CTs (Siement SGT6-5000F) w/ DB	200 MW	DLN and SCR	2.5 ppmvd @ 15% O ₂	BACT-PSD
Peace Vally Generation Company, LLC	GA	6/1/2003	(3) Combined Cycle CTs (GE 7FA) w/DB	1,550 Net MW	DLN and SCR	2.5 ppmvd @ 15% O ₂	BACT-PSD
Mcintosh Combined Cycle Facility	GA	4/17/2003	(4) Combined Cycle CT (GE 7FA)/HRSG	140 MW	DLN and SCR	2.5 ppmvd @ 15% O ₂	BACT-PSD
Wansley Combined Cycle Energy Facility	GA	1/15/2002	(2) CTs (Siemens V84.3a2)/HRSG	521 Net MW	DLN and SCR	3.0 ppmvd @ 15% O ₂	BACT-PSD
Effingham County Power	GA	12/27/2001	(2) Combined Cycle CT (GE 7FA)/HRSG	185 MW	SCR	3.0 ppmvd @ 15% O ₂	BACT-PSD
<u>EPA Region 4 (AL, FL, GA, KY, MS, NC, SC, TN)</u>							
Shady Hills GE	FL	11/13/2008	(3) GE7FA CTs	170 MW (EACH)	DLN	9 ppmvd @ 15% O ₂	BACT-PSD
OUC Curtis H. Stanton Energy Center	FL	5/12/2008	300 MW Combined Cycle CT	1765 MMBtu/hr	LNb and SCR	8 ppmvd @ 15% O ₂	BACT-PSD
FPL West County Energy Center Unit 3	FL	4/25/2008	Combined Cycle CTs - 3 Units	2,333 MMBtu/hr	DLN and SCR	2.0 ppmvd @ 15% O ₂	BACT-PSD
Progress Bartow Power Plant	FL	1/26/2007	Combined Cycle CT (4-On-1)	1,972 MMBtu/hr	WI	15.0 ppmvd uncorrected	BACT-PSD
FPL West County Energy Center Units 1 & 2	FL	1/10/2007	Combined Cycle CTs - 6 Units	2,333 MMBtu/hr	DLN and SCR	2.0 ppmvd @ 15% O ₂	BACT-PSD
Forsyth Energy Plant	NC	9/29/2005	(3) Turbine, Combined Cycle, Natural Gas	1,844 MMBtu/hr	DLN and SCR	2.5 ppm @ 15% O ₂	BACT-PSD
Progress Energy Hines Power Block 4	FL	6/8/2005	Combined Cycle Turbine	530 MW	SCR	2.5 ppm	BACT-PSD
FPL Turkey Point Power Plant	FL	2/8/2005	(4) Combustion Turbines	170 MW	DLN and SCR	2.0 ppmvd @ 15% O ₂	BACT-PSD
Reliant Energy Choctaw County, LLC	MS	11/23/2004	3 CTs (GE 7FB), 2,126 MMBtu/hr each	230 MW	DLN and SCR	3.5 ppmvd @ 15% O ₂	BACT-PSD
Hines Energy Complex, Power Block 3	FL	9/8/2003	(2) Combined Cycle CTs	1,830 MMBtu/hr	DLN and SCR	2.5 ppmvd @ 15% O ₂	BACT-PSD
FPL Martin Plant	FL	4/16/2003	(4) Turbine, Combined Cyle, Natural Gas	170 MW	DLN, SCR	2.5 ppmvd @ 15% O ₂	BACT-PSD
FPL Martin Plant	FL	4/16/2003	(4) Turbine, Simple Cycle, Natural Gas	170 MW	DLN, SCR	9.0 ppmvd @ 15% O ₂	BACT-PSD
FPL Martin Plant	FL	4/16/2003	Combined Cycle CT With Duct Burner	170 MW	DLN, SCR	2.5 ppm @ 15% O ₂	BACT-PSD
FPL Manatee Plant - Unit 3	FL	4/15/2003	(4) Turbine, Combined Cycle, Natural Gas	170 MW	DLN, SCR	2.5 ppmvd @ 15% O ₂	BACT-PSD
FPL Manatee Plant - Unit 3	FL	4/15/2003	(4) Turbine, Simple Cycle, Natural Gas	170 MW	DLN, SCR	9.0 ppmvd @ 15% O ₂	BACT-PSD
<u>Other States</u>							
Bosque County Power Plant	TX	2/27/2009	Electric Generation	170 MW	DLN	9 ppmvd @ 15% O ₂	BACT-PSD
CPV St. Charles	MD	11/12/2008	(2) Combustion Turbines		DLN and SCR	2 ppmvd @ 15% O ₂	BACT-PSD
Great River Energy - Elk River Station	MN	7/1/2008	Combustion Turbine Generator	2169 MMBTU/H	DLN	9 ppm	BACT-PSD
Gateway Generating Station	CA	7/1/2008	(2) Combined Cycle CT (GE 7FA)/HRSG	530 Net MW	DLN and SCR	2.0 ppmvd @ 15% O ₂	BACT-PSD
Colusa Generating Station	CA	5/1/2008	(2) Combined Cycle CT/HRSG	172 MW	DLN and SCR	2.0 ppmvd @ 15% O ₂	BACT-PSD
Arsenal Hill Power Plant	LA	3/20/2008	(2) Combined Cycle Gas Turbines	2,110 MMBtu/hr	Low Nox Turbines, SCR	30.15 lb/hr	BACT-PSD
Arsenal Hill Power Plant	LA	3/20/2008	(2) Combined Cycle Gas Turbines	2,110 MMBtu/hr	DLN and SCR	30.15 lb/hr	BACT-PSD
CPV Warren, LLC	VA	1/14/2008	Electric Generation - Scenario 1	1,717 MMBtu/hr	DLN, GCP and SCR	2.0 ppmvd @ 15% O ₂	BACT-PSD
CPV Warren, LLC	VA	1/14/2008	Electric Generation - Scenario 2	1,944 MMBtu/hr	DLN, GCP and SCR	2.0 ppmvd @ 15% O ₂	BACT-PSD
CPV Warren, LLC	VA	1/14/2008	Electric Generation - Secnario 3	2,204 MMBtu/hr	DLN, GCP and SCR	2.0 ppmvd @ 15% O ₂	BACT-PSD
Russell City Enery Center	CA	6/19/2007	(2) CTs (Westinghouse 501F)/HRSG	600 Net MW	DLN and SCR	2.0 ppmvd @ 15% O ₂	BACT-PSD
Faribault Energy Park	MN	6/5/2007	Combined Cycle CT W/Duct Burner	1,758 MMBtu/hr	DLN and SCR	3.0 ppmvd @ 15% O ₂	BACT-PSD
Blythe Energy Project II, LLC	CA	4/25/2007	(2) Combustion Turbines	170 MW	SCR	2.0 ppmvd	BACT-PSD
PSO Southwestern Power Pit	OK	2/9/2007	Gas-Fired Turbines		DLN	9.0 ppm	BACT-PSD
Lawton Energy Cogen Facility	OK	12/12/2006	Combustion Turbine And Duct Burner		DLN and SCR	3.5 ppmvd	BACT-PSD
Caithnes Bellport Energy Center	NY	5/10/2006	Combustion Turbine	2,221 MMBtu/hr	SCR	2.0 ppmvd @ 15% O ₂	BACT-PSD
Rocky Mountain Energy Center, LLC	CO	5/2/2006	Combined-Cycle Turbine	300 MW	DLN and SCR	3.0 ppm @ 15% O ₂	BACT-PSD
City Public Service Jk Spruce Electrice Generating	TX	12/28/2005	Spruce Power Generator Unit No 2			1,600 lb/hr	BACT-PSD
Tracy Substation Expansion Project	NV	8/16/2005	Combined Cycle CT/HRSG and DB	306 MW	SCR	2.0 ppm @ 15% O ₂	BACT-PSD
Wanapa Energy Center	OR	8/8/2005	(4) CT/HRSG and DB	2,384 MMBtu/hr	DLN and SCR	2.0 ppmvd @ 15% O ₂	BACT-PSD

TABLE 4-1
SUMMARY OF NO_x BACT DETERMINATIONS FOR NATURAL GAS-FIRED CTS (2003-2009)

Facility Name	State	Permit Issued	Process Info	MW/Heat Input	Control Method	NO _x Limit	Basis
Crescent City Power	LA	6/6/2005	(2) Gas Turbines - 187 MW	2,006 MMBtu/hr	DLN and SCR	21.8 lb/hr	BACT-PSD
Duke Energy Washington County, LLC	OH	5/9/2005	(2) Turbines (Model GE7FA), DB On	170 MW	DLN and SCR	3.5 ppmvd @ 15% O ₂	BACT-PSD
Duke Energy Washington County, LLC	OH	5/9/2005	(2) Turbines (Model GE7FA), DB Off	170 MW	DLN and SCR	3.5 ppmvd @ 15% O ₂	BACT-PSD
Berrien Energy, LLC	MI	4/13/2005	(3) CT w/ Duct Burners	1,584 MMBtu/hr	DLN and SCR	2.5 ppmvd @ 15% O ₂	BACT-PSD
BP Cherry Point Cogeneration Project	WA	1/11/2005	CT (Model GE 7FA)/HRSG	174 MW	DLN and SCR	2.5 ppmvd	BACT-PSD
Duke Energy Hanging Rock Energy Facility	OH	12/28/2004	(4) Turbines (Model GE7FA), DB On	172 MW	DLN and SCR	3.0 ppmvd @ 15% O ₂	BACT-PSD
Duke Energy Hanging Rock Energy Facility	OH	12/28/2004	(4) Turbines (Model GE7FA), DB Off	172 MW	DLN and SCR	3.0 ppmvd @ 15% O ₂	BACT-PSD
Pastoria Energy Facility	CA	12/23/2004	(3) Combustion Turbines	168 MW	XONON or DLN with SCR	2.5 ppmvd	BACT-PSD
Sabine Pass Lng Import Terminal	LA	11/24/2004	(4) 30 MW Gas Turbine Generators	290 MMBtu/hr	DLN	29 lb/hr	BACT-PSD
Reliant Energy Choctaw County, LLC	MS	11/23/2004	(3) GE 7FB CTS (230 MW, ea.)	2,126 MMBtu/hr	DLN and SCR	3.5 ppmvd @ 15% O ₂	BACT-PSD
El Dorado Energy, LLC	NV	8/19/2004	(2) Combined Cycle CT & Cogen	475 MW	DLN and SCR	3.5 ppm @ 15% O ₂	BACT-PSD
Sutter Power Plant	CA	8/16/2004	(2) Combustion Turbines	170 MW	DLN and SCR	2.5 ppmvd	BACT-PSD
Curran Creek	UT	5/17/2004	(2) Natural Gas Fired Turbines And HRSGs		SCR	2.25 ppmvd	BACT-PSD
Copper Mountain Power	NV	5/14/2004	Large CTS, Combined Cycle & Cogeneration	600 MW	DLN and SCR	2.0 ppmvd	BACT-PSD
Duke Energy Wythe, LLC	VA	2/5/2004	Combined Cycle CT	170 MW	SCR and DLN, GCP	2.5 ppmvd	BACT-PSD
Duke Energy Wythe, LLC	VA	2/5/2004	Combined Cycle CT, DB	170 MW	SCR and DLN, GCP	2.5 ppmvd	BACT-PSD
COB Energy Facility, LLC	OR	12/30/2003	(4) Combined Cycle CT, DB	1,150 MW	DLN and SCR	2.5 ppmvd @ 15% O ₂	BACT-PSD
Ivanpah Energy Center, L.P.	NV	12/29/2003	Large CTS, Combined Cycle & Cogeneration	500 MW	DLN and SCR	2.0 ppmvd	BACT-PSD
Mankato Energy Center	MN	12/4/2003	Large CT, 2 Each	1,916 MMBtu/hr	Lean Pre-Mix Combustion & SCR	3.0 ppmvd @ 15% O ₂	BACT-PSD
Mankato Energy Center	MN	12/4/2003	Large CT, 2 Each	1,827 MMBtu/hr	WI and SCR	5.5 ppmvd @ 15% O ₂	BACT-PSD
James City Energy Park	VA	12/1/2003	Combined Cycle CT	1,973 MMBtu/hr	DLN and SCR	2.5 ppm	BACT-PSD
James City Energy Park	VA	12/1/2003	Combined Cycle CT, DB	1,973 MMBtu/hr	DLN and SCR	2.5 ppm	BACT-PSD
Duke Energy Arlington Valley (AVEFII)	AZ	11/12/2003	Combined Cycle CT, DB	325 MW	SCR	2.0 ppm @ 15% O ₂	BACT-PSD
Duke Energy Arlington Valley (AVEFII)	AZ	11/12/2003	Combined Cycle CT	325 MW	SCR	2.0 ppm @ 15% O ₂	BACT-PSD
Redbud Power Plant	OK	6/3/2003	Combustion Turbine And Duct Burners	1,832 MMBtu/hr	DLN and SCR	3.5 ppmvd @ 15% O ₂	BACT-PSD
Magnolia Power Project, Scppa	CA	5/27/2003	Gas Turbine	181 Net MW	SCR	2.0 ppmvd @ 15% O ₂	BACT-PSD
Mirant Sugar Creek, LLC	IN	4/23/2003	(4) Combined Cycle, Startup & Shut Down	1,491 MMBtu/hr	DLN Burners, GCP	64.9 TPY	BACT-PSD
Sumas Energy 2 Generation Facility	WA	4/17/2003	(2) Turbines, Combined Cycle	660 MW	DLN, SCR	2.0 ppmvd	BACT-PSD
Duke Energy Stephens, Llc Stephens Energy	OK	3/21/2003	(2) Turbines, Combined Cycle	1,701 MMBtu/hr	DLN, SCR	3.5 ppm @ 15% O ₂	BACT-PSD
Kalkaska Generating, Inc	MI	2/4/2003	(2) Turbine, Combined Cycle	605 MW	DLN and SCR	3.0 ppmvd @ 15% O ₂	BACT-PSD
South Shore Power, LLC	MI	1/30/2003	(2) Turbine, Combined Cycle	172 MW	DLN & SCR	3.0 ppmvd @ 15% O ₂	BACT-PSD
Mirant Wyandotte, LLC	MI	1/28/2003	(2) Turbine, Combined Cycle	2,200 MMBtu/hr	DLN and SCR	3.5 ppm	BACT-PSD
Bluewater Energy Center, LLC	MI	1/7/2003	(3) Turbine, Combined Cycle	180 MW	DLN and SCR	4.5 ppmvd	BACT-PSD

Source: EPA 2010 (RBLC database); Golder, 2010

Note: DLN= dry low NO_x; SCR= selective catalytic reduction; WI= water injection; SI=Steam Injection; GCP= good combustion practices

TABLE 4-2
SUMMARY OF NO_x BACT DETERMINATIONS FOR FUEL OIL-FIRED CTS (2000-2009)

Facility Name	State	Permit Issued	Process Info	MW/Heat Input	Fuel	Control Method	NO _x Limit	Basis
<u>Georgia</u>								
McIntosh Combined Cycle Facility	GA	4/17/2003	(4) Combined Cycle CT (GE 7FA)/HRSG	140 MW	Fuel Oil	DLN and SCR	6 ppmvd @ 15% O ₂	BACT-PSD
<u>EPA Region 4 (AL, FL, GA, KY, MS, NC, SC, TN)</u>								
Shady Hills GE	FL	11/13/2008	(3) GE7FA CTs	170 MW (EACH)	Fuel Oil	WI and limited fuel usage	42 ppmvd @ 15% O ₂	BACT-PSD
FPL West County Energy Center Unit 3	FL	4/25/2008	Combined Cycle CTs - 3 Units	2,333 MMBtu/hr	Fuel Oil	DLN and SCR	8.0 ppmvd @ 15% O ₂	BACT-PSD
FPL - Turkey Point Power Plant	FL	2/8/2005	(4) Combined Cycle CTs and HRSGs	170 MW (EACH)	Fuel Oil	DLN and SCR	8.0 ppmvd @ 15% O ₂	BACT-PSD
FPL Martin Plant	FL	4/16/2003	(4) Turbines, Combined Cycle,	170 MW	Distillate Fuel Oil	SCR and WI	10 ppmvd @ 15% O ₂	BACT-PSD
SCE&G - Jasper County Generating Facility	SC	5/23/2002	Turbines (3 each)	170 MW (EACH)	0.05% No. 2 Oil	SCR and WI	7.5 ppm @ 15% O ₂	BACT-PSD
Fayetteville Generation, LLC.	NC	1/10/2002	(2) CT, CC	1940 MMBtu/hr	No. 2 Fuel Oil	SCR and WI	18 ppmvd	BACT-PSD
Broad River Investors - Gaffney	SC	12/21/2000	(2) CTs	193 MW (EACH)	No. 2 Fuel Oil	DLN, SI, Proper Op. and Maint.	12 ppmvd @ 15% O ₂	BACT-PSD
Rainey Generating Station	SC	4/3/2000	(2) CTs, CC	170 MW (EACH)	Distillate Fuel Oil	DLN, WI	341 lb/hr	BACT-PSD
Santee Cooper Rainey Generation Station	SC	4/3/2000	(2) CT, CC	170 MW	Fuel Oil	WI	341 lb/hr	BACT-PSD
<u>Other States</u>								
TVA - Kemper Combustion Turbine Plant	MS	12/10/2004	General Electric Combustion Turbines		No. 2 Fuel Oil		42 ppm @ 15% O ₂	BACT-PSD
Fairbault Energy Park	MN	7/15/2004	(1) CT, CC	1801 MMBtu/hr	No. 2 Distillate Oil	SCR and WI	6 ppmvd @ 15% O ₂	BACT-PSD
Tenaska Bear Garden Station	VA	4/30/2002	GE 7 FA Dual Fired CTs	2029 MMBtu	Distillate Fuel Oil	SCR and CEMs	2.5 ppm	BACT-PSD
Middleton Facility	ID	10/19/2001	(2) Gas Turbines w/o Duct Burners	1699 MMBtu/hr	Distillate Fuels	SCR, Catalytic Oxidation	26 lb/hr	BACT-PSD
Gray's Ferry Cogen Partnership	PA	3/21/2001	CT, CC	1515 MMBtu/hr	No. 2 Fuel Oil	SCR	0.17 lb/MMBtu	BACT-PSD
San Juan Repowering Project	PR	3/2/2000	(2) CTs, HRSGs	232 MW (EACH)	No. 2 Fuel Oil	SI System	219 lb/hr	BACT-PSD
LSP Nelson Energy, LLC.	IL	1/28/2000	CT, CC w/o Duct Burner	2166 MMBtu/hr	Fuel Oil	SCR and WI	0.065 lb/MMBtu	BACT-PSD
LSP Nelson Energy, LLC.	IL	1/28/2000	CT, CC w/ Duct Burner	2166 MMBtu/hr	Fuel Oil	SCR and WI	0.056 lb/MMBtu	BACT-PSD

Source: EPA 2010 (RBLC database); Golder, 2010

Note: DLN= dry low NO_x; SCR= selective catalytic reduction; WI= water injection; SI=Steam Injection; GCP= good combustion practices

TABLE 4-3
SUMMARY OF CO BACT DETERMINATIONS FOR NATURAL GAS-FIRED CTS (2003-2009)

Facility Name	State	Permit Issued	Process Info	MW/Heat Input	Control Method	CO Limit	Basis
Georgia							
Live Oaks Power Project	GA	4/8/2010	(2) CTs (Siement SGT6-5000F) w/o DB	200 MW	Oxidation Catalyst	2.0 ppmvd @ 15% O ₂	BACT-PSD
Live Oaks Power Project	GA	4/8/2010	(2) CTs (Siement SGT6-5000F) w/ DB	200 MW	Oxidation Catalyst	3.2 ppmvd @ 15% O ₂	BACT-PSD
McDonough Combined Cycle Plant	GA	1/7/2008	(6) CTs (Mitsubishi M501G) w/ DB	254 MW	Oxidation Catalyst	1.8 ppm @ 15% O ₂	BACT-PSD
Peace Vally Generation Company, LLC	GA	6/1/2003	(3) Combined Cycle CTs (GE 7FA) w/ DB	1550 Net MW	Oxidation Catalyst	2.0 ppmvd @ 15% O ₂	BACT-PSD
Mcintosh Combined Cycle Facility	GA	4/17/2003	(4) Turbine, Combined Cycle, Natural Gas	140 MW	Catalytic Oxidation	2.0 ppmvd @ 15% O ₂	BACT-PSD
GenPower Rincon, LLC	GA	3/24/2003	(2) Combined Cycle CT (GE 7FA)/HRSG	171.7 MW	Catalytic Oxidation	2.0 ppmvd @ 15% O ₂	BACT-PSD
Wansley Combined Cycle Energy Facility	GA	1/15/2002	(2) CTs (Siemens V84.3a2)/HRSG	521 Net MW	GCP	2.0 ppmvd @ 15% O ₂	BACT-PSD
Effingham County Power	GA	12/27/2001	(2) Combined Cycle CT (GE 7FA)/HRSG	185 MW	GCP	9.0 ppmvd @ 15% O ₂	BACT-PSD
EPA Region 4 (AL, FL, GA, KY, MS, NC, SC, TN)							
Shady Hills GE	FL	11/13/2008	(3) GE7FA CTs	170 MW (EACH)	GCP, Clean Fuels	12 ppmvd	BACT-PSD
OUC Curtis H. Stanton Energy Center	FL	05/12/2008	300 MW Combined Cycle CT	1765 MMBtu/hr	GCP	8 ppmvd @ 15% O ₂	BACT-PSD
FPL West County Energy Center Unit 3	FL	4/25/2008	Combined Cycle CTs - 3 Units	2,333 MMBtu/hr	Oxidation Catalyst	4.1 ppmvd @ 15% O ₂	BACT-PSD
Progress Bartow Power Plant	FL	01/26/2007	Combined Cycle CT (4-On-1)	1,972 MMBtu/hr	GCP	8.0 ppmvd	BACT-PSD
Progress Bartow Power Plant	FL	01/26/2007	Simple Cycle CT (One Unit)	1,972 MMBtu/hr	GCP	8.0 ppmvd	BACT-PSD
FPL West County Energy Center Units 1 & 2	FL	01/10/2007	Combined Cycle CT - 6 Units	2,333 MMBtu/hr	GCP	8.0 ppmvd @ 15% O ₂	BACT-PSD
Forsyth Energy Plant	NC	09/29/2005	(3) Turbine, Combined Cycle, Natural Gas	1,844 MMBtu/hr	GCP And Efficient Process Design.	11.6 ppm @ 15% O ₂	BACT-PSD
Forsyth Energy Plant	NC	09/29/2005	(3) CT+DB, Combined Cycle	1,844 MMBtu/hr	GCP And Efficient Process Design	25.9 ppm @ 15% O ₂	BACT-PSD
Hines Power Block 4	FL	06/08/2005	Combined Cycle Turbine	530 MW	Good Combustion	8.0 ppm	BACT-PSD
FPL Turkey Point Power Plant	FL	02/08/2005	170 MW Combustion Turbine, 4 Units	170 MW	Efficient Combustion of NG	4.1 ppmvd @ 15% O ₂	BACT-PSD
Reliant Energy Choctaw County, LLC	MS	11/23/2004	3 CTs (GE 7FB), 2,126 MMBtu/hr each	230 MW		18.36 ppmvd @ 15% O ₂	BACT-PSD
FPL Martin Plant	FL	04/16/2003	(4) Turbine, Combined Cyle, Natural Gas	170 MW	GCP	10.0 ppmvd @ 15% O ₂	BACT-PSD
FPL Martin Plant	FL	04/16/2003	(4) Turbine, Simple Cycle, Natural Gas	170 MW	GCP	8.0 ppmvd @ 15% O ₂	BACT-PSD
FPL Manatee Plant - Unit 3	FL	04/15/2003	(4) Turbine, Combined Cycle, Natural Gas	170 MW	GCP	10.0 ppmvd @ 15% O ₂	BACT-PSD
FPL Manatee Plant - Unit 3	FL	04/15/2003	(4) Turbine, Simple Cycle, Natural Gas	170 MW	GCP	7.4 ppmvd @ 15% O ₂	BACT-PSD
Other States							
Bosque County Power Plant	TX	2/27/2009	Electric Generation	170 MW	GCP	9 PPMVD	BACT-PSD
CPV St. Charles	MD	11/12/2008	(2) Combustion Turbines		Oxidation Catalyst	2 ppmvd @ 15% O ₂	BACT-PSD
Great River Energy - Elk River Station	MN	7/1/2008	Combustion Turbine Generator	2169 MMBtu/hr	GCP	4 ppm	BACT-PSD
Gateway Generating Station	CA	7/1/2008	(2) Combined Cycle CT (GE 7FA)/HRSG	530 Net MW	Oxidation Catalyst	4.0 ppmvd @ 15% O ₂	BACT-PSD
Colusa Generating Station	CA	5/1/2008	(2) Combined Cycle CT/HRSG	172 MW	Oxidation Catalyst	3.0 ppmvd @ 15% O ₂	BACT-PSD
Arsenal Hill Power Plant	LA	03/20/2008	(2) Combined Cycle Gas Turbines	2,110 MMBtu/hr	Proper Operating Practices	143.31 lb/hr	BACT-PSD
Kleen Energy Systems, LLC	CT	02/25/2008	(2) CT (Siemens SGT6-5000f) w/ DB	2,136 MMBtu/hr	Oxidation Catalyst	0.9 ppmvd @ 15% O ₂	BACT-PSD
Kleen Energy Systems, LLC	CT	02/25/2008	(2) CT (Siemens SGT6-5000f), DB	2,581 MMBtu/hr	Oxidation Catalyst	0.9 ppmvd @ 15% O ₂	BACT-PSD
CPV Warren, LLC.	VA	01/14/2008	Electric Generation - Scenario 1	1,717 MMBtu/hr	NG Only, GCP, Oxidation Catalyst	12.8 lb/hr	BACT-PSD
CPV Warren, LLC.	VA	01/14/2008	Electric Generation - Scenario 2	1,944 MMBtu/hr	GCP and Oxidation Catalyst.	1.2 ppmvd	BACT-PSD
CPV Warren, LLC.	VA	01/14/2008	Electric Generation - Scenario 3	2,204 MMBtu/hr	GCP and Oxidation Catalyst.	1.8 ppmvd	BACT-PSD
Russell City Enery Center	CA	6/19/2007	(2) CTs (Westinghouse 501F)/HRSG	600 Net MW	Oxidation Catalyst	4.0 ppmvd @ 15% O ₂	BACT-PSD
Fairbault Energy Park	MN	06/05/2007	Combined Cycle CT W/Duct Burner	1,758 MMBtu/hr	GCP	9.0 ppmvd	BACT-PSD
Blythe Energy Project II, LLC	CA	04/25/2007	(2) Combustion Turbines	170 MW		4.0 ppmvd	BACT-PSD
Pso Southwestern Power Pit	OK	02/09/2007	Gas-Fired Turbines		Combustion Control	25.0 ppmvd	BACT-PSD
Lawton Energy Cogen Facility	OK	12/12/2006	Combustion Turbine And Duct Burner		GCP	16.38 ppmvd	BACT-PSD
Calthnes Bellport Energy Center	NY	05/10/2006	Combustion Turbine	2,221 MMBtu/hr	Oxidation Catalyst	2.0 ppmvd @ 15% O ₂	BACT-PSD
Rocky Mountain Energy Center, LLC	CO	05/02/2006	Natural-Gas Fired, Combined-Cycle Turbine	300 MW	GCP and Oxidation Catalyst.	3.0 ppm @ 15% O ₂	BACT-PSD
JK Spruce Electric Generating Unit 2	TX	12/28/2005	Spruce Power Generator Unit No 2			4480 lb/hr	BACT-PSD
Tracy Substation Expansion Project	NV	08/16/2005	Combined Cycle CT/HRSG and DB	306 MW	Oxidation Catalyst	3.5 ppm @ 15% O ₂	BACT-PSD
Tracy Substation Expansion Project	NV	08/16/2005	Combined Cycle CT/HRSG and DB	306 MW	Oxidation Catalyst System	3.5 ppm @ 15% O ₂	BACT-PSD
Wanapa Energy Center	OR	08/08/2005	CT/HRSG	2,384 MMBtu/hr	Oxidation Catalyst.	2.0 ppmvd @ 15% O ₂	BACT-PSD

TABLE 4-3
SUMMARY OF CO BACT DETERMINATIONS FOR NATURAL GAS-FIRED CTS (2003-2009)

Facility Name	State	Permit Issued	Process Info	MW/Heat Input	Control Method	CO Limit	Basis
Crescent City Power	LA	06/06/2005	(2) Gas Turbines - 187 MW	2,006 MMBtu/hr	GCP and Oxidation Catalyst.	17.7 lb/hr	BACT-PSD
Duke Energy Washington County, LLC	OH	05/09/2005	(2) Turbines (Model GE7FA), DB On	170 MW		14 ppmvd @ 15% O ₂	BACT-PSD
Duke Energy Washington County, LLC	OH	05/09/2005	(2) Turbines (Model GE7FA), DB Off	170 MW		10 ppmvd @ 15% O ₂	BACT-PSD
Berrien Energy, LLC	MI	04/13/2005	(3) Combustion Turbines And DB	1,584 MMBtu/hr	Catalytic Oxidation.	2.0 ppmvd @ 15% O ₂	BACT-PSD
BP Cherry Point Cogeneration Project	WA	01/11/2005	GE7FA CT&HRSG	174 MW	Lean Pre-Mix Ct Burner & Ox Catalyst	2.0 ppmvd	BACT-PSD
Duke Energy Hanging Rock Energy Facility	OH	12/28/2004	(4) Turbines (Model GE7FA), DB On	172 MW		9.0 ppmvd @ 15% O ₂	BACT-PSD
Duke Energy Hanging Rock Energy Facility	OH	12/28/2004	(4) Turbines (Model GE7FA), DB Off	172 MW		6.0 ppmvd @ 15% O ₂	BACT-PSD
Pastoria Energy Facility	CA	12/23/2004	(3) Combustion Turbines	168 MW	DLN	6.0 ppmvd	BACT-PSD
Sabine Pass Lng Import Terminal	LA	11/24/2004	(4) 30 MW Gas Turbine Generators	290 MMBtu/hr ea.	GCP	17.8 lb/hr	BACT-PSD
Sutter Power Plant	CA	08/16/2004	(2) Combustion Turbines	170 MW	Oxidation Catalyst System	4.0 ppmvd	BACT-PSD
Curran Creek	UT	05/17/2004	(2) Natural Gas Fired Turbines And HRSGs		Oxidation Catalyst	3.0 ppmvd	BACT-PSD
Duke Energy Wythe, LLC	VA	02/05/2004	Combined Cycle CT	170 MW	GCP	9.0 ppmvd	BACT-PSD
Duke Energy Wythe, LLC	VA	02/05/2004	Combined Cycle CT, DB	170 MW	GCP	14.6 ppmvd	BACT-PSD
COB Energy Facility, LLC	OR	12/30/2003	(4) Combined Cycle CT, DB	1,150 MW	Catalytic Oxidation	2.0 ppmvd @ 15% O ₂	BACT-PSD
Mankato Energy Center	MN	12/04/2003	Combustion Turbine, Large, 2 Each	1,916 MMBtu/hr	GCP and Oxidation Catalyst.	4.0 ppmvd @ 15% O ₂	BACT-PSD
Mankato Energy Center	MN	12/04/2003	Combustion Turbine, Large 2 Each	1,827 MMBtu/hr	GCP and Oxidation Catalyst.	4.8 ppmvd @ 15% O ₂	BACT-PSD
James City Energy Park	VA	12/01/2003	Turbine, Combined Cycle, Natural Gas	1,973 MMBtu/hr	GCP	9.0 ppm	BACT-PSD
James City Energy Park	VA	12/01/2003	Combined Cycle CT w/ Duct Burner	1,973 MMBtu/hr	GCP	12.0 ppm	BACT-PSD
Duke Energy Arlington Valley (Avefii)	AZ	11/12/2003	Combined Cycle CT w/ Duct Burner	325 MW	Catalytic Oxidizer	3.0 ppm @ 15% O ₂	BACT-PSD
Duke Energy Arlington Valley (Avefii)	AZ	11/12/2003	Turbine, Combined Cycle	325 MW	Catalytic Oxidizer	2.0 ppm @ 15% O ₂	BACT-PSD
Hines Energy Complex, Power Block 3	FL	09/08/2003	(2) Combined Cycle CTS	1,830 MMBtu/hr	GCP and Oxidation Catalyst.	10.0 ppmvd @ 15% O ₂	BACT-PSD
Redbud Power Plant	OK	06/03/2003	Combustion Turbine And Duct Burners	1,832 MMBtu/hr	GCP	17.2 ppmvd	BACT-PSD
Magnolia Power Project, Scppa	CA	05/27/2003	Gas Turbine	181 NET MW	Oxidation Catalyst	2.0 ppmvd @ 15% O ₂	BACT-PSD
Mirant Sugar Creek, LLC	IN	04/23/2003	(4) Combined Cycle, Startup & Shut Down	1,491 MMBtu/hr	GCP, NG As Fuel.	82.5 tpy	BACT-PSD
Midland Cogeneration (Mcv)	MI	04/21/2003	(11) Turbine, Combined Cycle	984 MMBtu/hr	Good Combustion Techniques.	26 lb/hr	BACT-PSD
Midland Cogeneration (Mcv)	MI	04/21/2003	(1) Turbine, Combined Cycle	984 MMBtu/hr	GCP	26 lb/hr	BACT-PSD
Sumas Energy 2 Generation Facility	WA	04/17/2003	(2) Turbines, Combined Cycle	660 MW	Oxidation Catalyst	2.0 ppmvd	BACT-PSD
Duke Energy Stephens, Llc Stephens Energy	OK	03/21/2003	(2) Turbines, Combined Cycle	1,701 MMBtu/hr	Combustion Control	10.0 ppm @ 15% O ₂	BACT-PSD
Kalkaska Generating, Inc	MI	02/04/2003	(2) Turbine, Combined Cycle,	605 MW	Oxidation Catalyst.	5.0 ppmvd @ 15% O ₂	BACT-PSD
South Shore Power, LLC	MI	01/30/2003	(2) Turbine, Combined Cycle	172 MW	Catalytic Oxidation And Use Of GCP	4.0 ppmvd @ 15% O ₂	BACT-PSD
Mirant Wyandotte, LLC	MI	01/28/2003	(2) Turbine, Combined Cycle	2,200 MMBtu/hr	Catalytic Oxidation System.	3.8 ppm	BACT-PSD
Bluewater Energy Center, LLC	MI	01/07/2003	(3) Turbine, Combined Cycle	180 MW	Catalytic Afterburner	41.7 lb/hr	BACT-PSD

Source: EPA 2010 (RBLC database); Golder, 2010

Note: DB = duct burner; DLN= dry low NOx; GCP= good combustion practices

TABLE 4-4
SUMMARY OF CO BACT DETERMINATIONS FOR FUEL OIL-FIRED CTS (2000-2009)

Facility Name	State	Permit Issued	Process Info	MW/Heat Input	Fuel	Control Method	CO Limit	Basis
<u>Georgia</u>								
Mcintosh Combined Cycle Facility	GA	4/17/2003	(4) Turbine, Combined Cycle	140 MW	Fuel Oil	Catalytic Oxidation	2 ppmvd @ 15% O ₂	BACT-PSD
<u>EPA Region 4 (AL, FL, GA, KY, MS, NC, SC, TN)</u>								
Shady Hills GE	FL	11/13/2008	(3) GE7FA CTs	170 MW (EACH)	Fuel Oil	GCP, Clean Fuels	20 ppmvd	BACT-PSD
FPL West County Energy Center Unit 3	FL	4/25/2008	Combined Cycle CTs - 3 Units	2,333 MMBtu/hr	Fuel Oil	Oxidation Catalyst	8.0 ppmvd @ 15% O ₂	BACT-PSD
FPL - Turkey Point Power Plant	FL	2/8/2005	(4) Combined Cycle CTs and HRSGs	170 MW (EACH)	Fuel Oil	GCP, Clean Fuels	8.0 ppmvd @ 15% O ₂	BACT-PSD
TVA - Kemper Combustion Turbine Plant	MS	12/10/2004	General Electric Combustion Turbines		No. 2 Fuel Oil		20 ppm @ 15% O ₂	BACT-PSD
FPL Martin Plant	FL	4/16/2003	(4) Turbines, Combined Cycle,	170 MW	Distillate Fuel Oil	GCP	15 ppmvd @ 15% O ₂	BACT-PSD
SCE&G - Jasper County Generating Facility	SC	5/23/2002	Turbines (3 each)	170 MW (Each)	0.05% No. 2 Oil	GCP	22 ppmvd	BACT-PSD
Fayetteville Generation, LLC	NC	1/10/2002	(2) CT, CC	1940 MMBtu/hr	No. 2 Fuel Oil	Combustion Control	20 ppmvd	BACT-PSD
Broad River Investors - Gaffney	SC	12/21/2000	(2) CTs	193 MW (Each)	No. 2 Fuel Oil	GCP, Clean Burning Fuels	15 ppmvd @ 15% O ₂	BACT-PSD
Rainey Generating Station	SC	4/3/2000	(2) CTs, CC	170 MW (Each)	Distillate Fuel Oil	GCP, Clean Burning Fuels	114 lb/hr	BACT-PSD
Santee Cooper Rainey Generation Station	SC	4/3/2000	(2) CT, CC	170 MW	Fuel Oil	GCP, Clean Burning Fuels	114 lb/hr	BACT-PSD
<u>Other States</u>								
Fairbault Energy Park	MN	7/15/2004	(1) CT, CC	1801 MMBtu/hr	NO. 2 Distillate Oil	GCP	10 ppmvd @ 15% O ₂	BACT-PSD
Tenaska Bear Garden Station	VA	4/30/2002	GE 7 FA Dual Fired CTs	2029 MMBtu/hr	Distillate Fuel Oil	GCP	222 TPY	BACT-PSD
Middleton Facility	ID	10/19/2001	(2) Gas Turbines w/o Duct Burners	1699 MMBtu/hr	Distillate Fuel	None Indicated	30.6 lb/hr	BACT-PSD
Gray's Ferry Cogen Partnership	PA	3/21/2001	CT, CC	1515 MMBtu/hr	No. 2 Fuel Oil	Oxidation Catalyst	0.0182 lb/MMBtu	BACT-PSD
San Juan Repowering Project	PR	3/2/2000	(2) CTs, HRSGs	232 MW (Each)	No. 2 Fuel Oil	GCP, Oxydation Catalyst	100 lb/hr	BACT-PSD
LSP Nelson Energy, LLC	IL	1/28/2000	CT, CC w/o Duct Burner	2166 MMBtu/hr	Fuel Oil	GCP and Combustion Controls	0.0986 lb/MMBtu	BACT-PSD
LSP Nelson Energy, LLC	IL	1/28/2000	CT, CC w/ Duct Burner	2166 MMBtu/hr	Fuel Oil	GCP and Combustion Controls	0.1024 lb/MMBtu	BACT-PSD

Source: EPA 2010 (RBLC database); Golder, 2010

Note: GCP= good combustion practices

TABLE 4-5
SUMMARY OF VOC BACT DETERMINATIONS FOR NATURAL GAS-FIRED CTS (2003-2009)

Facility Name	State	Permit Issued	Process Info	MW/Heat Input	Control Method	VOC Limit	Basis
Georgia							
Live Oaks Power Project	GA	4/8/2010	(2) CTS (Siement SGT6-5000F) w or w/o DB	200 MW	Oxidation Catalyst	2.0 ppmvd @ 15% O ₂	BACT-PSD
McDonough Combined-Cycle Generating Units	GA	1/7/2008	(6) CTS (Mitsubishi M501G) w/ DB	250 MW	Oxidation Catalyst	1.8 ppmvd @ 15 % O ₂	LAER
Mcintosh Combined Cycle Facility	GA	4/17/2003	(4) Combined Cycle CT (GE 7FA)/HRSG	140 MW	Catalytic Oxidation	2 ppm @ 15% O ₂	BACT-PSD
EPA Region 4 (AL, FL, GA, KY, MS, NC, SC, TN)							
Shady Hills GE	FL	11/13/2008	(3) GE7FA CTS	170 MW (EACH)	GCP, Clean Fuels	1.4 ppmvd	BACT-PSD
FPL West County Energy Center Unit 3	FL	4/25/2008	Combined Cycle CTS - 3 Units	2,333 MMBtu/hr	Oxidation Catalyst	1.2 ppmvd @ 15% O ₂	BACT-PSD
Progress Bartow Power Plant	FL	1/26/2007	Combined Cycle CT and DB (4-On-1)	1972 MMBtu/hr	GCP	1.5 ppmvd	BACT-PSD
Progress Bartow Power Plant	FL	1/26/2007	Combined Cycle CT (4-On-1)	1972 MMBtu/hr	GCP	1.2 ppmvd	BACT-PSD
FPL West County Energy Center	FL	1/10/2007	Combined Cycle CT - 6 Units	2333 MMBtu/hr	GCP	1.2 ppmvd @ 15 % O ₂	BACT-PSD
FPL West County Energy Center	FL	1/10/2007	Combined Cycle CT and DB - 6 Units	2761 MMBtu/hr	GCP	1.6 ppmvd @ 15 % O ₂	BACT-PSD
Forsyth Energy Plant	NC	9/29/2005	Turbine, Combined Cycle, Natural Gas, (3)	1844.3 MMBtu/hr	GCP and Efficient Process Design	5.7 ppm @ 15% O ₂	BACT-PSD
FPL Turkey Point Power Plant	FL	2/8/2005	170 Mw Combustion Turbine, 4 Units	170 MW	GCP	1.3 ppmvd @ 15 % O ₂	BACT-PSD
Reliant Energy Choctaw County, LLC	MS	11/23/2004	3 GE 7FB Turbines (230 MW, ea.)	2126 MMBtu/hr	GCP	3.64 ppmvd @ 15 % O ₂	BACT-PSD
Hines Energy Complex, Power Block 3	FL	9/8/2003	2 Combined Cycle CTS	1830 MMBtu/hr	Combustion Design, GCP	2 ppmvd @ 15 % O ₂	BACT-PSD
FPL Martin Plant	FL	4/16/2003	4 Combined Cycle CTS	170 MW	GCP	1.3 ppmvd @ 15 % O ₂	BACT-PSD
FPL Martin Plant	FL	4/16/2003	Combined Cycle CT and DB	170 MW	GCP	4 ppmvd @ 15 % O ₂	BACT-PSD
FPL Manatee Plant - Unit 3	FL	4/15/2003	4 Combined Cycle CTS	170 MW	GCP	1.3 ppmvd @ 15 % O ₂	BACT-PSD
FPL Manatee Plant - Unit 3	FL	4/15/2003	Combined Cycle CT and DB	170 MW	GCP	4 ppmvd @ 15 % O ₂	BACT-PSD
Other States							
Bosque County Power Plant	TX	2/27/2009	Electric Generation	170 MW	GCP	4 ppmvd	BACT-PSD
Arsenal Hill Power Plant	LA	3/20/2008	Two Combined Cycle CTS	2110 MMBtu/hr	Proper Operating Practices	12.06 lb/hr	BACT-PSD
Kleen Energy Systems, LLC	CT	2/25/2008	Siemens SGT6-5000f CT #1 and #2	2136 MMBtu/hr	Oxidation Catalyst	5.0 ppmvd @ 15 % O ₂	BACT-PSD
Kleen Energy Systems, LLC	CT	2/25/2008	(2) Siemens SGT6-5000f CT+DB	2581 MMBtu/hr	Oxidation Catalyst	5.0 ppmvd @ 15 % O ₂	BACT-PSD
CPV Warren LLC	VA	1/14/2008	Electric Generation - Scenario 1	1717 MMBtu/hr	GCP and Oxidation Catalyst	0.7 ppmvd	BACT-PSD
CPV Warren LLC	VA	1/14/2008	Electric Generation - Scenario 2	1944 MMBtu/hr	GCP and Oxidation Catalyst	0.7 ppmvd	BACT-PSD
CPV Warren LLC	VA	1/14/2008	Electric Generation - Scenario 3	2204 MMBtu/hr	GCP and Oxidation Catalyst	0.7 ppmvd	BACT-PSD
Faribault Energy Park	MN	6/5/2007	Combined Cycle CT with Duct Burner	1758 MMBtu/hr	GCP	1.5 ppmvd	BACT-PSD
Rocky Mountain Energy Center, Llc	CO	5/2/2006	Combined Cycle CT	300 MW	NG only, GCP and Oxidation Catalyst.	0.0029 lb/MMBtu	BACT-PSD
City Public Service Jk Spruce Electrice Generating	TX	12/28/2005	Spruce Power Generator Unit No 2			29 lb/hr	BACT-PSD
Tracy Substation Expansion Project	NV	8/16/2005	Combined Cycle CT/HRSG and DB	306 MW	Oxidation Catalyst	4 ppm @ 15% O ₂	BACT-PSD
Tracy Substation Expansion Project	NV	8/16/2005	Combined Cycle CT/HRSG and DB	306 MW	Oxidation Catalyst	4 ppm @ 15% O ₂	BACT-PSD
Xcel Energy High Bridge Generating Plant	MN	8/12/2005	CT/HRSG and DB - 2 Units	2384.1 MMBtu/hr	NG Fuel	2 ppmvd @ 15 % O ₂	BACT-PSD
Wanapa Energy Center	OR	8/8/2005	CT/HRSG and DB - 4 Units	2384.1 MMBtu/hr	NG Fuel, Oxidation Catalyst	19.7 lb/hr	BACT-PSD
Crescent City Power	LA	6/6/2005	Gas Turbines - 187 Mw (2)	2006 MMBtu/hr	GCP and Oxidation Catalyst	2.8 lb/hr	BACT-PSD
Berrien Energy, Llc	MI	4/13/2005	3 Combustion Turbines And Duct Burners	1584 MMBtu/hr	Catalytic Oxidizer	3.2 lb/hr	BACT-PSD
Bp Cherry Point Cogeneration Project	WA	1/11/2005	GE7FA CT/HRSG	174 MW	Lean Pre-Mix CT Burner & Ox Catalyst		BACT-PSD
Duke Energy Hanging Rock Energy Facility	OH	12/28/2004	Turbines (4) (Model GE7FA), DB On	172 MW	GCP	20.4 lb/hr	BACT-PSD
Duke Energy Hanging Rock Energy Facility	OH	12/28/2004	Turbines (4) (Model GE7FA), DB Off	172 MW	GCP	3.2 lb/hr	BACT-PSD
Sabine Pass Lng Import Terminal	LA	11/24/2004	30 Mw Gas Turbine Generators (4)	290 MMBtu/hr Ea.	GCP and Natural Gas Fuel	1.2 lb/hr	BACT-PSD
El Dorado Energy, LLC	NV	8/19/2004	Combined Cycle CT & Cogen(2)	475 MW	NG Only and GCP	5.2 lb/hr	BACT-PSD
Duke Energy Wythe, LLC	VA	2/5/2004	Combined Cycle CT and DB	170 MW	GCP	3 lb/hr	BACT-PSD

TABLE 4-5
SUMMARY OF VOC BACT DETERMINATIONS FOR NATURAL GAS-FIRED CTS (2003-2009)

Facility Name	State	Permit Issued	Process Info	MW/Heat Input	Control Method	VOC Limit	Basis
Duke Energy Wythe, LLC	VA	2/5/2004	Combined Cycle CT and DB	170 MW	GCP	21 lb/hr	BACT-PSD
Cob Energy Facility, LLC	OR	12/30/2003	Combined Cycle CT and DB	1150 MW	GCP and Oxidation Catalyst	7.1 lb/hr	BACT-PSD
Ivanpah Energy Center, L.P.	NV	12/29/2003	Combined Cycle CT	500 MW	GCP and Oxidation Catalyst	2.3 ppmvd	BACT-PSD
Mankato Energy Center	MN	12/4/2003	Combustion Turbine, Large, 2 Each	1916 MMBtu/hr	GCP and Oxidation Catalyst	34 ppmvd @ 15 % O ₂	BACT-PSD
Mankato Energy Center	MN	12/4/2003	Combustion Turbine, Large 2 Each	1827 MMBtu/hr	GCP and Oxidation Catalyst	7.1 ppmvd @ 15 % O ₂	BACT-PSD
Duke Energy Arlington Valley (Avefii)	AZ	11/12/2003	Turbine, Combined Cycle & Duct Burner	325 MW		4 ppm	BACT-PSD
Duke Energy Arlington Valley (Avefii)	AZ	11/12/2003	Turbine, Combined Cycle	325 MW		1 ppm	BACT-PSD
Duke Energy Washington County LLC	OH	8/14/2003	Turbines (2) (Model GE 7FA), DB On	170 MW	GCP	19.6 lb/hr	BACT-PSD
Duke Energy Washington County LLC	OH	8/14/2003	Turbines (2) (Model GE 7FA), DB Off	170 MW	GCP	3 lb/hr	BACT-PSD
Magnolia Power Project, Scppa	CA	5/27/2003	Gas Turbine	181 NET MW	Oxidation Catalyst	2 ppmvd @ 15 % O ₂	BACT-PSD
Sumas Energy 2 Generation Facility	WA	4/17/2003	2 Combined Cycle CTs	660 MW	GCP	420 lb/d	BACT-PSD
Duke Energy Stephens, LLC Stephens Energy	OK	3/21/2003	Turbines, Combined Cycle (2)	1701 MMBtu/hr	Good Combustion and DLN	45.6 lb/hr	BACT-PSD
Kalkaska Generating, Inc	MI	2/4/2003	Turbine, Combined Cycle, (2)	605 MW	Oxidation Catalyst	3.5 ppm	BACT-PSD
South Shore Power Llc	MI	1/30/2003	Turbine, Combined Cycle, (2)	172 MW	Oxidation Catalyst	7.3 lb/hr	Other Case-by-
Mirant Wyandotte Llc	MI	1/28/2003	Turbine, Combined Cycle, (2)	2200 MMBtu/hr	GCP and Oxidation Catalyst	10 ppm	Other Case-by-
Bluewater Energy Center LLC	MI	1/7/2003	3 Combined Cycle CTs	180 MW	Catalytic Afterburner.	28 lb/hr	BACT-PSD

Source: EPA 2010 (RBLC database); Golder, 2010

Note: DLN= dry low NOx; GCP= good combustion practices.

TABLE 4-6
SUMMARY OF VOC BACT DETERMINATIONS FOR FUEL OIL-FIRED CTS (2000-2009)

Facility Name	State	Permit Issued	Process Info	MW/Heat Input	Fuel	Control Method	VOC Limit	Basis
Georgia								
McIntosh Combined Cycle Facility	GA	4/17/2003	(4) Combined Cycle CT (GE 7FA)/HRSG	140 MW	Fuel Oil	Catalytic Oxidation	2 ppmvd @ 15% O ₂	BACT-PSD
EPA Region 4 (AL, FL, GA, KY, MS, NC, SC, TN)								
Shady Hills GE	FL	11/13/2008	(3) GE7FA CTs	170 MW (EACH)	Fuel Oil	GCP, Clean Fuels	7 ppmvw	BACT-PSD
FPL West County Energy Center Unit 3	FL	4/25/2008	Combined Cycle CTs - 3 Units	2,333 MMBtu/hr	Fuel Oil	Oxidation Catalyst	6.0 ppmvd @ 15% O ₂	BACT-PSD
FPL - Turkey Point Power Plant	FL	2/8/2005	(4) Combined Cycle CTs and HRSGs	170 MW (EACH)	Fuel Oil	GCP, Clean Fuels	2.8 ppmvd @ 15% O ₂	
TVA - Kemper Combustion Turbine Plant	MS	12/10/2004	General Electric Combustion Turbines		No. 2 Fuel Oil		70 lb/hr	BACT-PSD
FPL Martin Plant	FL	4/16/2003	(4) Turbines, Combined Cycle,	170 MW ea.	Distillate Fuel Oil	GCP	2.5 ppmvd @ 15% O ₂	BACT-PSD
Fayetteville Generation, LLC.	NC	1/10/2002	(2) CT, CC	1940 MMBtu/hr	No. 2 Fuel Oil	GCP	7 ppmvd	BACT-PSD
Rainey Generating Station	SC	4/3/2000	(2) CTs, CC	170 MW (EACH)	Distillate Fuel Oil	GCP, Clean Fuels	8 lb/hr	BACT-PSD
Santee Cooper Rainey Generation Station	SC	4/3/2000	(2) CT, CC	170 MW	Fuel Oil	GCP, Clean Fuels	8 lb/hr	BACT-PSD
Other States								
Fairbault Energy Park	MN	7/15/2004	(1) CT, CC	1801 MMBtu/hr	No. 2 Distillate Oil	GCP	5 ppmvd @ 15% O ₂	BACT-PSD
Gray's Ferry Cogen Partnership	PA	3/21/2001	CT, CC	1515 MMBtu/hr	No. 2 Fuel Oil	GCP	0.026 lb/MMBtu	BACT-PSD
San Juan Repowering Project	PR	3/2/2000	(2) CTs, HRSGs	232 MW (EACH)	No. 2 Fuel Oil	GCP, Catalytic Oxidation	15 lb/hr	BACT-PSD
LSP Nelson Energy, LLC.	IL	1/28/2000	CT, CC w/o Duct Burner	2166 MMBtu/hr	Fuel Oil	GCP	0.0157 lb/MMBtu	BACT-PSD
LSP Nelson Energy, LLC.	IL	1/28/2000	CT, CC w/ Duct Burner	2166 MMBtu/hr	Fuel Oil	GCP	0.023 lb/MMBtu	BACT-PSD

Source: EPA 2010 (RBLC database); Golder, 2010

Note: DLN= dry low NOx; GCP= good combustion practices.

TABLE 4-7
CAPITAL AND ANNUAL COSTS FOR OXIDATION CATALYST SYSTEM FOR ONE GE 7FA CT

Cost Items/Emissions	Parameters	Oxidation Catalyst System for GE 7FA CT
ANNUALIZED COSTS (AC) (\$):		
(1) CO Catalyst System (Frame+CO Modules)	Vendor Quote ^(a)	995,000
Auxiliary Equipment (ducts, catalyst housing)	Assumed Included	0
Instrumentation and Controls	10% of equipment cost, Control Cost manual (CCM) Chapter 2	99,500
(2) Freight	5% of equipment cost, CCM Chapter 2	49,750
(3) Sales Tax	NA - Pollution Control Equipment	0
Subtotal: Total Equipment Cost (TEC)		1,144,250
(4) Direct Installation Costs ^(b)		
CONTRO (a) Design, Installation, and Materials by Vendor	Vendor Quote ^(a)	735,000
(b) Foundation and Structural Support	Assumed Included	0
(c) Handling & Erection	Assumed Included	0
(d) Electrical	Assumed Included	0
(e) Piping and Wiring	Assumed Included	0
(f) Insulation	Assumed Included	0
(g) Painting	Assumed Included	0
(h) Sample Ports	Assumed Included	0
Total DCC:		1,879,250
INDIRECT CAPITAL COSTS (ICC): ^(b)		
(1) Indirect Installation Costs		
(a) General Facilities	5% of TEC, CCM Section 4, Table 2.5	57,213
(b) Engineering	10% of TEC, CCM Section 4, Table 2.5	114,425
(c) Process Contingency	5% of TEC, CCM Section 4, Table 2.5	57,213
CONTROLLED VOC EMISSIONS ^(b)		
(2) Other Indirect Costs		
(a) Emissions Monitoring	Engineering Estimate	10,000
(b) Performance Testing	1% of TEC, CCM Section 3, Table 2.8	11,443
(c) Contractor Fees	10% of TEC, CCM Section 3, Table 2.8	114,425
Total ICC:		364,718
PROJECT CONTINGENCY	15% of (DCC+ICC)	336,595
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC+Project Contingency	2,580,563
DIRECT OPERATING COSTS (DOC): ^(b)		
(1) Operating Labor		
Operator	1/2 hr/shift, \$30/hr, 8760 hrs/yr	16,425
Supervisor	15% of operator cost	2,464
(2) Maintenance (labor and material)	1.5% of TCI, CCM Section 4, Equation 2.46	38,708
(3) MW Loss Penalty	Estimated 0.1% of Design Output of 200 MW, \$0.06/kWh	105,120
(4) Catalyst Replacement Cost	7 Years catalyst life, 50% catalyst replaced	71,071
Total DOC:		233,789
INDIRECT OPERATING COSTS (IOC): ^(b)		
(1) Overhead	60% of oper. labor & maintenance, CCM Chapter 2	34,558
(2) Property Taxes	Assumed none	0
(3) Insurance	1% of total capital investment, CCM Chapter 2	25,806
(4) Administration	2% of total capital investment, CCM Chapter 2	51,611
Total IOC:	(1) + (2) + (3) + (4)	111,975
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.1098 times TCI (15 yrs @ 7%)	283,346
ANNUALIZED COSTS (AC):	DOC + IOC + CRC	629,110

Notes:

^(a) Cost estimates from Nooter Eriksen for 2 CO Catalyst Systems for Constellation Energy's 700-MW Hillabee Energy Center Project. Budgetary proposal No. 2008041080, dated 4/17/08.

^(b) Factors and cost estimates reflect OAQPS Cost Manual, 6th Edition, January 2002.

TABLE 4-8
COST EFFECTIVENESS CALCULATION FOR OXIDATION CATALYST SYSTEM FOR ONE GE 7FA CT

Cost Items/Emissions	Parameters	Oxidation Catalyst System for GE 7FA CT
ANNUALIZED COSTS (AC) (\$):	See Table 4-7	629,110
UNCONTROLLED CO EMISSIONS		
CO emissions for NG Firing and without DB (TPY) :	3.0 ppmvd, 12.5 lb/hr for 1,601 hours (see Table 2-4)	10.0
CO emissions for NG Firing and with DB (TPY) :	10.0 ppmvd, 52.0 lb/hr for 4,000 hours (see Table 2-4)	104.0
CO emissions for fuel oil-firing (TPY) :	20.0 ppmvd, 92.8 lb/hr for 1,000 hours (see Table 2-4)	46.4
CO emissions from startup/shutdown (TPY) :	Warm - 153.6 lb/hr (749 hrs), Cold - 289.1 lb/hr (50 hrs), Shutdown - 62 lb/hr (300 hrs)	74.1
Potential CO emissions from one CT (TPY) :		234.5
CONTROLLED CO EMISSIONS ^(a)		
CO emissions for NG Firing and without DB (TPY) :	2.0 ppmvd	6.7
CO emissions for NG Firing and with DB (TPY) :	2.0 ppmvd, 80% control	20.8
CO emissions for fuel oil-firing (TPY) :	4.0 ppmvd, 80% control	9.3
CO emissions from startup/shutdown (TPY) :	80% Control	14.8
Potential controlled CO emissions from one CT (TPY) :		51.6
Reduction in CO Emissions (TPY):		183
UNCONTROLLED VOC EMISSIONS		
VOC emissions for NG Firing and without DB (TPY) :	1.4 ppmvd, 3.3 lb/hr for 3,760 hours (see Table 2-4)	6.2
VOC emissions for NG Firing and with DB (TPY) :	2.0 ppmvd, 5.9 lb/hr for 4,000 hours (see Table 2-4)	11.8
VOC emissions for fuel oil-firing (TPY) :	3.5 ppmvd, 9.3 lb/hr for 1,000 hours (see Table 2-4)	4.7
Potential VOC emissions from one CT (TPY) :		22.7
CONTROLLED VOC EMISSIONS ^(b)		
VOC emissions for NG Firing and without DB (TPY) :	1.0 ppmvd	4.4
VOC emissions for NG Firing and with DB (TPY) :	1.0 ppmvd, 50% control	5.9
VOC emissions for fuel oil-firing (TPY) :	1.75 ppmvd, 50% control	2.3
Potential Controlled VOC emissions from one CT (TPY) :		12.7
Reduction in VOC Emissions (TPY):		10
Total Reduction in CO and VOC Emissions (TPY):		193
Cost Effectiveness:	\$ per ton of CO and VOC Removed	3,261

Notes:

^(a) Controlled emissions are calculated based on an estimated CO BACT limit of 2.0 ppmvd for natural gas firing with an oxidation catalyst system. For the oil-f case and startup/shutdown cases, controlled emissions are based on 80% control.

^(b) Controlled emissions are calculated based on an estimated 50% control of VOC emissions. For NG-firing only case, controlled emissions are based on the

TABLE 4-9
SUMMARY OF PM BACT DETERMINATIONS FOR NATURAL GAS-FIRED CTS (2003-2009)

Facility Name	State	Permit Issued	Process Info	MW/Heat Input	Control Method	PM/PM ₁₀ /PM _{2.5} Limit	PM/PM ₁₀ /PM _{2.5} Emissions Rate	Basis
Georgia								
Live Oaks Power Project	GA	4/8/2010	(2) CTs (Siement SGT6-5000F) w/o DB	200 MW	NG Fuel with 0.5 gr/100 scf S	-- --	0.0064 lb/MMBtu	BACT-PSD
Live Oaks Power Project	GA	4/8/2010	(2) CTs (Siement SGT6-5000F) w/ DB	200 MW	NG Fuel with 0.5 gr/100 scf S	-- --	0.0054 lb/MMBtu	BACT-PSD
Peace Vally Generation Company, LLC	GA	6/1/2003	(3) CTs (GE 7FA)/Duct Burners	1,550 Net MW	NG Fuel	0.011 lb/MMBtu	0.011 lb/MMBtu	BACT-PSD
Mcintosh Combined Cycle Facility	GA	4/17/2003	(4) Combined Cycle CT (GE 7FA)	140 MW	Clean Fuel, GCP	0.009 lb/MMBtu	0.009 lb/MMBtu	BACT-PSD
GenPower Rincon, LLC	GA	3/24/2003	(2) Combined Cycle CT (GE 7FA)/HRSG	172 MW	Firing NG	0.011 lb/MMBtu	0.011 lb/MMBtu	BACT-PSD
Wansley Combined Cycle Energy Facility	GA	1/15/2002	(2) CTs (Siemens V84.3a2)/HRSG	521 NET MW	GCP, Low Sulfur Fuel	0.011 lb/MMBtu	0.011 lb/MMBtu	BACT-PSD
Effingham County Power	GA	12/27/2001	(2) Combined Cycle CT (GE 7FA)/HRSG	185 MW	Clean Fuel, GCP	21.6 lb/hr		BACT-PSD
Other States								
Shady Hills GE	FL	11/13/2008	(3) GE7FA CTs	170 MW (EACH)	GCP, Clean Fuels	10 lb/hr		BACT-PSD
OUC Curtis H. Stanton Energy Center	FL	5/12/2008	300 MW Combined Cycle CT	1765 MMBtu/hr	NG Fuel			BACT-PSD
FPL West County Energy Center Unit 3	FL	4/25/2008	Combined Cycle CTs - 3 Units	2,333 MMBtu/hr	Oxidation Catalyst	2 gr S/100 scf		BACT-PSD
FPL West County Energy Center	FL	1/10/2007	CC CTs - 6 Units	2,333 MMBtu/hr	NG only, GCP	2 gr S/100 scf	0.0015 lb/MMBtu	BACT-PSD
Forsyth Energy Plant	NC	9/29/2005	(3) Turbine, CC, NG	1,844 MMBtu/hr	LSF and GCP	0.019 lb/MMBtu	0.0190 lb/MMBtu	BACT-PSD
Forsyth Energy Plant	NC	9/29/2005	(3) Turbine & DB, CC, NG	1,844 MMBtu/hr	LSF and GCP	0.021 lb/MMBtu	0.0210 lb/MMBtu	BACT-PSD
Hines Power Block 4	FL	6/8/2005	CC Turbine	1,915 MMBtu/hr	Clean Fuels	10 % Opacity	0.0053 lb/MMBtu	BACT-PSD
FPL Turkey Point Power Plant	FL	2/8/2005	(4) 170 MW CT	1,776 MMBtu/hr	GCP		0.0051 lb/MMBtu	BACT-PSD
Reliant Energy Choctaw County, LLC	MS	11/23/2004	Combined Cycle GE CT (Aa-003)	230 MW each		20.59 lb/hr		BACT-PSD
Hines Energy Complex, Power Block 3	FL	9/8/2003	(2) CC CTs	1,830 MMBtu/hr	GCP and Clean Fuel			BACT-PSD
FPL Martin Plant	FL	4/16/2003	(4) Turbine, CC, NG	2,095 MMBtu/hr	Use of NG			BACT-PSD
FPL Manatee Plant - Unit 3	FL	4/15/2003	(4) Turbine, CC, NG	2,095 MMBtu/hr	NG			BACT-PSD
Other States								
Bosque County Power Plant	TX	2/27/2009	Electric Generation	170 MW	GCP, NG as Fuel	0.01 lb/MMBtu	0.01 lb/MMBtu	BACT-PSD
CPV St. Charles	MD	11/12/2008	(2) Combustion Turbines			0.012 lb/MMBtu	0.012 lb/MMBtu	BACT-PSD
Arsenal Hill Power Plant	LA	3/20/2008	(2) Combined Cycle Gas Turbines	2,110 MMBtu/hr	GCP, NG as Fuel	24.23 lb/hr	24.23 lb/hr	BACT-PSD
Gateway Generating Station	CA	7/1/2008	(2) Combined Cycle CT (GE 7FA)/HRSG	530 Net MW	NG with 0.75 gr/100 scf S			BACT-PSD
Colusa Generating Station	CA	5/1/2008	(2) Combined Cycle CT/HRSG	172 MW		20 lb/hr		BACT-PSD
Arsenal Hill Power Plant	LA	3/20/2008	Two CC Gas Turbines	2,110 MMBtu/hr	GCP, NG as Fuel	24.23 lb/hr	0.0115 lb/MMBtu	BACT-PSD
Kleen Energy Systems, LLC	CT	2/25/2008	(2) CT (Siemens SGT6-5000f)	2,136 MMBtu/hr	NG Fuel	11 lb/hr	0.0051 lb/MMBtu	BACT-PSD
Kleen Energy Systems, LLC	CT	2/25/2008	(2) CT (Siemens SGT6-5000f) w/ DB	2,581 MMBtu/hr	NG Fuel	15.2 lb/hr	0.0059 lb/MMBtu	BACT-PSD
CPV Warren	VA	1/14/2008	Electric Generation - Scenario 1	1,717 MMBtu/hr	GCP	0.013 lb/MMBtu	0.0130 lb/MMBtu	N/A
CPV Warren	VA	1/14/2008	Electric Generation - Scenario 2	1,944 MMBtu/hr	GCP	12.5 lb/hr	0.0064 lb/MMBtu	N/A
CPV Warren	VA	1/14/2008	Electric Generation - Secnario 3	2,204 MMBtu/hr	GCP	9.9 lb/hr	0.0045 lb/MMBtu	N/A
Russell City Enery Center	CA	6/19/2007	(2) CTs (Westinghouse 501F)/HRSG	600 Net MW	NG with 0.25 gr/100 scf S			BACT-PSD
Fairbault Energy Park	MN	6/5/2007	CC CT w/DB	1,758 MMBtu/hr		0.01 lb/MMBtu	0.0100 lb/MMBtu	BACT-PSD
Blythe Energy Project II, LLC	CA	4/25/2007	2 CTs	1,776 MMBtu/hr ea.	NG with 0.5 gr S/100 SCF	6 lb/hr	0.0034 lb/MMBtu	BACT-PSD
PSO Southwestern Power Plant	OK	2/9/2007	Gas-Fired Turbines		NG and Efficient Combustion	0.0093 lb/MMBtu	0.0093 lb/MMBtu	BACT-PSD
Lawton Energy Cogen Facility	OK	12/12/2006	CT And DB		GCP	0.0067 lb/MMBtu	0.0067 lb/MMBtu	BACT-PSD
Caithnes Bellport Energy Center	NY	5/10/2006	CT/HRSG	2,221 MMBtu/hr	LSF	0.0055 lb/MMBtu	0.0055 lb/MMBtu	BACT-PSD
Caithnes Bellport Energy Center	NY	5/10/2006	CT/HRSG and DB	2,715 MMBtu/hr	LSF	0.0066 lb/MMBtu	0.0066 lb/MMBtu	BACT-PSD
Rocky Mountain Energy Center, LLC	CO	5/2/2006	NG Fired, CC Turbine	300 MW	NG only and GCP	0.0074 lb/MMBtu	0.0074 lb/MMBtu	BACT-PSD
Tracy Substation Expansion Project	NV	8/16/2005	CC CT/HRSG and DB	306 MW	Best Combustion Practices.	0.011 lb/MMBtu	0.0110 lb/MMBtu	BACT-PSD

TABLE 4-9
SUMMARY OF PM BACT DETERMINATIONS FOR NATURAL GAS-FIRED CTS (2003-2009)

Facility Name	State	Permit Issued	Process Info	MW/Heat Input	Control Method	PM/PM ₁₀ /PM _{2.5} Limit	PM/PM ₁₀ /PM _{2.5} Emissions Rate	Basis
Tracy Substation Expansion Project	NV	8/16/2005	Combined Cycle CT/HRSG and DB	306 MW	Best Combustion Practices.	0.011 lb/MMBtu	0.0110 lb/MMBtu	BACT-PSD
Wanapa Energy Center	OR	8/8/2005	CT/HRSG	2,384 MMBtu/hr				BACT-PSD
Crescent City Power	LA	6/6/2005	(2) Gas Turbines - 187 Mw	2,006 MMBtu/hr	GCP and Clean Fuel	29.4 lb/hr	0.0147 lb/MMBtu	BACT-PSD
Duke Energy Washington County, LLC	OH	5/9/2005	(2) Turbines (GE 7FA), DBs On	170 MW		28 lb/hr		BACT-PSD
Duke Energy Washington County, LLC	OH	5/9/2005	(2) Turbines (GE 7FA), DBs Off	170 MW		19 lb/hr		BACT-PSD
Berrien Energy, LLC	MI	4/13/2005	(3) CTs And DBs	1,584 MMBtu/hr	GCP, use of NG	19 lb/hr	0.0120 lb/MMBtu	BACT-PSD
Bp Cherry Point Cogeneration Project	WA	1/11/2005	(3) GE7FA CT/HRSG	1,614 MMBtu/hr ea.	Only NG	20.6 lb/hr		BACT-PSD
Duke Energy Hanging Rock Energy Facility	OH	12/28/2004	(4) Turbines (GE7FA), DBs On	172 MW		23.3 lb/hr		BACT-PSD
Duke Energy Hanging Rock Energy Facility	OH	12/28/2004	(4) Turbines (GE7FA), DBs Off	172 MW		15 lb/hr		BACT-PSD
Sutter Power Plant	CA	8/16/2004	(2) CT	170 MW		11.5 lb/hr		BACT-PSD
Currant Creek	UT	5/17/2004	NG Fired Turbines And HRSGs			0.066 lb/MMBtu	0.0660 lb/MMBtu	BACT-PSD
Duke Energy Wythe, LLC	VA	2/5/2004	CC CT	170 MW	GCP	17.5 lb/hr		BACT-PSD
Duke Energy Wythe, LLC	VA	2/5/2004	CC CT, DB	170 MW	GCP	23.7 lb/hr		BACT-PSD
COB Energy Facility, LLC	OR	12/30/2003	CC CT, DB	1,150 MW	GCP, use of NG	14 lb/hr		BACT-PSD
Mankato Energy Center	MN	12/4/2003	Large CT, 2 Each	1,916 MMBtu/hr	GCP and Clean Fuel	0.009 lb/MMBtu	0.0090 lb/MMBtu	BACT-PSD
Mankato Energy Center	MN	12/4/2003	Large CT, 2 Each	1,827 MMBtu/hr	GCP and Clean Fuel	0.057 lb/MMBtu	0.0570 lb/MMBtu	BACT-PSD
James City Energy Park	VA	12/1/2003	Turbine, Combined Cycle, Natural Gas	1,973 MMBtu/hr	GCP and Clean Fuel	18 lb/hr	0.0091 lb/MMBtu	
James City Energy Park	VA	12/1/2003	Burner	1,973 MMBtu/hr	GCP and Clean Fuel	24.7 lb/hr	0.0125 lb/MMBtu	
Duke Energy Arlington Valley (Avefii)	AZ	11/12/2003	CC CT, DB	325 MW		25 lb/hr	25 lb/hr	BACT-PSD
Duke Energy Arlington Valley (Avefii)	AZ	11/12/2003	CC CT	325 MW		18 lb/hr	18 lb/hr	BACT-PSD
Redbud Power Plant	OK	6/3/2003	CT And DBs	1,832 MMBtu/hr	Efficient Combustion	0.012 lb/MMBtu	0.0120 lb/MMBtu	BACT-PSD
Magnolia Power Project, Scppa	CA	5/27/2003	Gas Turbine: Combined Cycle >= 50 Mw	181 NET MW		0.01 gr/scf		BACT-PSD
Sumas Energy 2 Generation Facility	WA	4/17/2003	(2) Turbines, CC	660 MW	GCP & LSF	194 lb/d (filterable)		BACT-PSD
Sumas Energy 2 Generation Facility	WA	4/17/2003	(2) Turbines, CC	660 MW	GCP & LSF	377 (condensable)		BACT-PSD
Duke Energy Stephens, LLC	OK	3/21/2003	(2) Turbines, CC	1,701 MMBtu/hr	GCP and Clean Fuel	0.015 lb/MMBtu	0.0150 lb/MMBtu	Case
Kalkaska Generating, Inc	MI	2/4/2003	(2) Turbine, CC	605 MW	GCP and Clean Fuel	38 lb/hr		BACT-PSD
South Shore Power, LLC	MI	1/30/2003	(2) Turbine, CC	172 MW	GCP	24 lb/hr		BACT-PSD
Mirant Wyandotte, LLC	MI	1/28/2003	(2) Turbine, CC	2,200 MMBtu/hr	GCP and Firing NG	16.8 lb/hr	0.0076 lb/MMBtu	BACT-PSD
Bluewater Energy Center, LLC	MI	1/7/2003	(3) Turbine, CC	180 MW	Only NG	19.6 lb/hr		BACT-PSD

Source: EPA 2010 (RBL database); Golder, 2010

Note: GCP= good combustion practices; LSF= low sulfur fuel; NG = natural gas; CC = combined cycle; CT = combustion turbine; DB = duct burner; HRSG = heat recovery steam generator.

TABLE 4-10
SUMMARY OF PM BACT DETERMINATIONS FOR FUEL OIL-FIRED CTS (2000-2009)

Facility Name	State	Permit Issued	Process Info	MW/Heat Input	Fuel	Control Method	PM/PM ₁₀ /PM _{2.5} Limit	Basis
Georgia								
Mcintosh Combined Cycle Facility	GA	4/17/2003	(4) Turbine, Combined Cycle	140 MW	Fuel Oil	Clean Fuel, GCP	0.016 lb/MMBtu	BACT-PSD
Other States								
Shady Hills GE	FL	11/13/2008	(3) GE7FA CTS	170 MW (EACH)	Fuel Oil	GCP, Clean Fuels	17 lb/hr	BACT-PSD
FPL West County Energy Center Unit 3	FL	4/25/2008	Combined Cycle CTS - 3 Units	2,333 MMBtu/hr	Fuel Oil	LSF, GCP	0.0015 % S in Fuel Oil	BACT-PSD
TVA - Kemper Combustion Turbine Plant	MS	12/10/2004	General Electric CTS		NO.2 Fuel Oil		54.4 TPY	BACT-PSD
Fairbault Energy Park	MN	7/15/2004	(1) CT, CC	1801 MMBtu/hr	#2 Distillate Oil	Clean Fuel and GCP		Other Case-by-Case
FPL Martin Plant	FL	4/16/2003	(4) Turbines, Combined Cycle,	170 MW	Distillate Fuel	Ultra LSF		BACT-PSD
SCE&G - Jasper County Generating Facility	SC	5/23/2002	Turbines (3 each)	170 MW (Each)	0.05% NO. 2 OIL	LSF, GCP	100.8 TPY	BACT-PSD
Fayetteville Generation, LLC	NC	1/10/2002	(2) CT, CC	1940 MMBtu/hr	No. 2 Fuel Oil	Combustion Control		BACT-PSD
Middleton Facility	ID	10/19/2001	(2) Gas Turbines w/o DB	1699 MMBtu/hr	Distillate Fuel	Pollution Prevention Precautions		BACT-PSD
Gray's Ferry Cogen Partnership	PA	3/21/2001	CT, CC	1515 MMBtu/hr	No. 2 Fuel Oil	GCP	32.5 lb/hr	BACT-PSD
San Juan Repowering Project	PR	3/2/2000	(2) CTS, HRSGs	232 MW (Each)	No. 2 Fuel Oil	GCP, LSF	0.0413 lb/MMBtu	BACT-PSD
LSP Nelson Energy, LLC	IL	1/28/2000	CT, CC w/o Duct Burner	2166 MMBtu/hr	Fuel Oil	GCP, LSF	77.9 lb/hr	BACT-PSD
LSP Nelson Energy, LLC	IL	1/28/2000	CT, CC w/ Duct Burner	2166 MMBtu/hr	Fuel Oil	GCP, LSF	85 lb/hr	BACT-PSD

Source: EPA 2010 (RBLC database); Golder, 2010

Note: GCP= good combustion practices; LSF= low sulfur fuel; NG = natural gas; CC = combined cycle; CT = combustion turbine; DB = duct burner; HRSG = heat recovery steam generator.

TABLE 4-11
SUMMARY OF NO_x, CO, VOC, AND PM BACT DETERMINATIONS FOR AUXILIARY BOILERS (2005-2009)

Facility Name	State	Permit Issued	Process Info	Fuel	MW/Heat Input	Control Method	Pollutant Limit	Basis
<u>Nitrogen Oxides (NO_x)</u>								
CPV St. Charles	MD	11/12/2008	Boiler	NG	93 MMBtu/hr	LNB with FGR	0.011 lb/MMBtu	BACT-PSD
Nellis Air Force Base	NV	2/26/2008	Boilers/Heaters	Diesel Oil		LNB with FGR	0.14 lb/MMBtu	BACT-PSD
CPV Warren LLC	VA	1/14/2008	Auxiliary Boiler - Scenario 2	NG	97 MMBtu/hr	CEM System	0.011 lb/MMBtu	N/A
CPV Warren LLC	VA	1/14/2008	Auxiliary Boiler - Scenario 3	NG	62 MMBtu/hr	CEM System	0.011 lb/MMBtu	N/A
Fairbault Energy Park	MN	6/5/2007	Boiler	NG	40 MMBtu/hr	LNB, FGR	0.04 lb/MMBtu	BACT-PSD
Fairbault Energy Park	MN	6/6/2007	Boiler	Distillate Oil	40 MMBtu/hr	LNB, FGR	0.058 lb/MMBtu	BACT-PSD
FPL West County Energy Center	FL	1/10/2007	Two 99.8 MMBtu/Hr Aux Boilers	NG	99.8 MMBtu/hr	GCP	0.05 lb/MMBtu	BACT-PSD
Lawton Energy Cogen Facility	OK	12/12/2006	Auxiliary Boiler	NG		DLN	0.036 lb/MMBtu	BACT-PSD
Caitlhes Bellport Energy Center	NY	5/10/2006	Auxiliary Boiler	NG	29.4 MMBtu/hr	LNB & FGR	0.011 lb/MMBtu	BACT-PSD
Forsyth Energy Plant	NC	9/29/2005	Auxiliary Boiler	NG	110.2 MMBtu/hr	LNB, GCP, Low-Sulfur NG	0.137 lb/MMBtu	BACT-PSD
Tracy Substation Expansion Project	NV	8/16/2005	Boiler, Auxiliary	NG	37.7 MMBtu/hr	Best Combustion Practices.	0.037 lb/MMBtu	BACT-PSD
<u>Volatile Organic Compounds (VOC)</u>								
CPV St. Charles	MD	11/12/2008	Boiler	NG	93 MMBtu/hr		0.002 lb/MMBtu	LAER
Nellis Air Force Base	NV	2/26/2008	Boilers/Heaters	Diesel Oil		GCP	0.0094 lb/MMBtu	Other Case-by-Case
Cpv Warren	VA	1/14/2008	Auxiliary Boiler - Scenario 2	NG	97 MMBtu/hr	CEM System	0.006 lb/MMBtu	N/A
Cpv Warren	VA	1/14/2008	Auxiliary Boiler - Scenario 3	NG	62 MMBtu/hr	CEM System	0.006 lb/MMBtu	N/A
Fairbault Energy Park	MN	6/5/2007	Boiler, Natural Gas (1)	NG	40 MMBtu/hr	GCP	0.006 lb/MMBtu	BACT-PSD
Progress Bartow Power Plant	FL	1/26/2007	One 99 MMBtu/Hr Aux Boiler	NG	99 MMBtu/hr		2 gr S/100 SCF	BACT-PSD
FPL West County Energy Center	FL	1/10/2007	Two 99.8 MMBtu/Hr Aux Boilers	NG	99.8 MMBtu/hr	GCP	2 gr S/100 SCF	BACT-PSD
Forsyth Energy Plant	NC	9/29/2005	Auxiliary Boiler	NG	110.2 MMBtu/hr	LNB, GCP, Low-Sulfur NG	0.0054 lb/MMBtu	BACT-PSD
Tracy Substation Expansion Project	NV	8/16/2005	Boiler, Auxiliary	NG	37.7 MMBtu/hr	Best Combustion Practices.	0.005 lb/MMBtu	BACT-PSD
<u>Particulate Matter (PM/PM₁₀/PM_{2.5})</u>								
CPV St. Charles	MD	11/12/2008	Boiler	NG	93 MMBtu/hr		0.005 lb/MMBtu	BACT-PSD
Nellis Air Force Base	NV	2/26/2008	Boilers/Heaters	Diesel Oil		GCP	0.019 lb/MMBtu	Other Case-by-Case
Fairbault Energy Park	MN	6/5/2007	Boiler, Natural Gas (1)	NG	40 MMBtu/hr	Clean Fuel and GCP	0.008 lb/MMBtu	BACT-PSD
FPL West County Energy Center	FL	1/10/2007	Two 99.8 MMBtu/Hr Aux Boilers	NG	99.8 MMBtu/hr	Use of NG	2 gr S/100 SCF	BACT-PSD
Caitlhes Bellport Energy Center	NY	5/10/2006	Auxiliary Boiler	NG	29.4 MMBtu/hr	Low-Sulfur Fuel	0.0033 lb/MMBtu	BACT-PSD
Forsyth Energy Plant	NC	9/29/2005	Auxiliary Boiler	NG	110.2 MMBtu/hr	LNB, GCP, Low-Sulfur NG	0.0074 lb/MMBtu	BACT-PSD
Tracy Substation Expansion Project	NV	8/16/2005	Boiler, Auxiliary	NG	37.7 MMBtu/hr	Best Combustion Practices	0.004 lb/MMBtu	BACT-PSD
Duke Energy Hanging Rock Energy Facility	OH	12/28/2004	Boilers (2)	NG	30.6 MMBtu/hr		0.01 lb/MMBtu	BACT-PSD
Fairbault Energy Park	MN	6/5/2007	Boiler	NG	40 MMBtu/hr	GCP	0.008 lb/MMBtu	BACT-PSD
Fairbault Energy Park	MN	6/6/2007	Boiler	Distillate Oil	40 MMBtu/hr	GCP	0.024 lb/MMBtu	BACT-PSD
<u>Carbon Monoxide (CO)</u>								
CPV St. Charles	MD	11/12/2008	Boiler	NG	93 MMBtu/hr		0.02 lb/MMBtu	BACT-PSD
Nellis Air Force Base	NV	2/26/2008	Boilers/Heaters	Diesel Oil		GCP	0.038 lb/MMBtu	Other Case-by-Case
CPV Warren, LLC.	VA	1/14/2008	Auxiliary Boiler - Scenario 2	NG	97 MMBtu/hr	GCP	0.036 lb/MMBtu	N/A
CPV Warren, LLC.	VA	1/14/2008	Auxiliary Boiler - Scenario 3	NG	62 MMBtu/hr	GCP	0.036 lb/MMBtu	N/A
Fairbault Energy Park	MN	6/5/2007	Auxiliary Boiler	NG	40 MMBtu/hr	GCP	0.084 lb/MMBtu	BACT-PSD
Progress Bartow Power Plant	FL	1/26/2007	One 99 MMBtu/Hr Auxiliary Boiler	NG	99 MMBtu/hr	GCP	0.08 lb/MMBtu	BACT-PSD
Fpl West County Energy Center	FL	1/10/2007	Two 99.8 Mmbtu/Hr Auxiliary Boilers	NG	99.8 MMBtu/hr	GCP	0.08 lb/MMBtu	BACT-PSD
Caitlhes Bellport Energy Center	NY	5/10/2006	Auxiliary Boiler	NG	29.4 MMBtu/hr	GCP	0.036 lb/MMBtu	BACT-PSD
Forsyth Energy Plant	NC	9/29/2005	Auxiliary Boiler	NG	110.2 MMBtu/hr	LNB, GCP	0.082 lb/MMBtu	BACT-PSD
Tracy Substation Expansion Project	NV	8/16/2005	Boiler, Auxiliary	NG	37.7 MMBtu/hr	GCP	0.036 lb/MMBtu	BACT-PSD

Source: EPA 2010 (RBLC database); Golder, 2010

Note: DLN= dry low NO_x; GCP= good combustion practices; LNB= low NO_x burner; FGR= flue gas recirculation

TABLE 4-12
SUMMARY OF BACT DETERMINATIONS FOR FUEL HEATERS (2005-2009)

Facility Name	State	Permit Issued	Process Info	Fuel	MW/Heat Input	Control Method	Pollutant Limit	Basis
<u>Nitrogen Oxides (NOX)</u>								
CPV St. Charles	MD	11/12/2008	Heater	NG	1.7 MMBtu/hr		0.1 lb/MMBtu	BACT-PSD
Fairbault Energy Park	MN	6/5/2007	Emergency Generator	Diesel	1,750 KW	GCP	0.024 lb/hp-hr	BACT-PSD
FPL West County Energy Center	FL	1/10/2007	Two 10 MMBtu/hr Process Heaters	NG	10 MMBtu/hr	GCP	0.095 lb/MMBtu	BACT-PSD
Tracy Substation Expansion Project	NV	8/16/2005	Fuel Preheater #2	NG	4 MMBtu/hr	GCP	0.14 lb/MMBtu	BACT-PSD
Tracy Substation Expansion Project	NV	8/16/2005	Fuel Preheater #1	NG	4 MMBtu/hr	GCP	0.14 lb/MMBtu	BACT-PSD
Crescent City Power	LA	6/6/2005	(3) Fuel Gas Heaters	NG	19 MMBtu/hr	LNB and GCP	0.095 lb/MMBtu	BACT-PSD
<u>Volatile Organic Compounds (VOC)</u>								
CPV St. Charles	MD	11/12/2008	Heater	NG	1.7 MMBtu/hr		0.005 lb/MMBtu	BACT-PSD
Progress Bartow Power Plant	FL	1/26/2007	(5) 3 Mmbtu/Hr Process Heaters	NG	3 MMBtu/hr		2 gr S/100 scf gas	BACT-PSD
FPL West County Energy Center	FL	1/10/2007	(2) CT (Siemens SGT6-5000f) w/ DB	NG	10 MMBtu/hr	GCP	2 gr S/100 scf gas	BACT-PSD
Tracy Substation Expansion Project	NV	8/16/2005	Fuel Preheater #2	NG	4 MMBtu/hr	GCP	0.08 lb/MMBtu	BACT-PSD
Tracy Substation Expansion Project	NV	8/16/2005	Fuel Preheater #1	NG	4 MMBtu/hr	GCP	0.08 lb/MMBtu	BACT-PSD
Crecent City Power	LA	6/6/2005	(3) Fuel Gas Heaters	NG	19 MMBtu/hr	GCP	0.0053 lb/MMBtu	BACT-PSD
<u>Particulate Matter (PM₁₀/PM_{2.5})</u>								
CPV St. Charles	MD	11/12/2008	Heater	NG	1.7 MMBtu/hr		0.007 lb/MMBtu	BACT-PSD
FPL West County Energy Center	FL	1/10/2007	(2) 10 MMBtu/hr Process Heaters	NG	10 MMBtu/hr	GCP	2 gr S/100 scf gas	BACT-PSD
Tracy Substation Expansion Project	NV	8/16/2005	Fuel Preheater #2	NG	4 MMBtu/hr	GCP	0.02 lb/MMBtu	BACT-PSD
Tracy Substation Expansion Project	NV	8/16/2005	Fuel Preheater #1	NG	4 MMBtu/hr	GCP	0.02 lb/MMBtu	BACT-PSD
Crecent City Power	LA	6/6/2005	(3) Fuel Gas Heaters	NG	19 MMBtu/hr	Use of NG and GCP	0.0074 lb/MMBtu	BACT-PSD
<u>Carbon Monoxide (CO)</u>								
CPV St. Charles	MD	11/12/2008	Heater	NG	1.7 MMBtu/hr		0.08 lb/MMBtu	BACT-PSD
Progress Bartow Power Plan	FL	1/26/2007	(5) 3 MMBtu/hr Process Heaters	NG	3 MMBtu/hr		0.08 lb/MMBtu	BACT-PSD
FPL West County Energy Center	FL	1/10/2007	(2) 10 MMBtu/hr Process Heaters	NG	10 MMBtu/hr	GCP	0.08 lb/MMBtu	BACT-PSD
Tracy Substation Expansion Project	NV	8/16/2005	Fuel Preheater #2	NG	4 MMBtu/hr	GCP	0.03 lb/MMBtu	BACT-PSD
Tracy Substation Expansion Project	NV	8/16/2005	Fuel Preheater #1	NG	4 MMBtu/hr	GCP	0.03 lb/MMBtu	BACT-PSD
Crecent City Power	LA	6/6/2005	(3) Fuel Gas Heaters	NG	19 MMBtu/hr	GCP	0.08 lb/MMBtu	BACT-PSD

Source: EPA 2010 (RBL database); Golder, 2010

Note: DLN= dry low NOx; SCR= selective catalytic reduction; WI= water injection; GCP= good combustion practices; LSF= low sulfur fuel; LNB= low NOx burner; FGR= flue gas recirculation

TABLE 4-13
SUMMARY OF BACT DETERMINATIONS FOR COOLING TOWERS (2005-2009)

Facility Name	State	Permit Issued	Process Info	MW/Heat Input	Control Method	Pollutant Limit	Basis
Live oaks Power Project	GA	4/8/2010	Cooling Tower	140,000 gal/min	Drift Eliminators, Max 0.001% DR		BACT-PSD
CPV St. Charles	MD	11/12/2008	Cooling Tower		Drift Eliminators, Max 0.0005% DR		BACT-PSD
FPL West County Energy Center Unit 3	FL	4/25/2008	Mechanical Draft Cooling Tower (26 Cell)	304,000 gal/min	Drift Eliminators, Max 0.0005% DR	1.2 lb/hr	
Arsenal Hill Power Plant	LA	3/20/2008	Cooling Tower	140,000 gal/min	Use Of Mist Eliminators	1.4 lb/hr	BACT-PSD
FPL West County Energy Center	FL	1/10/2007	(2) Cooling Tower (26 Cell Mechanical Draft)	306,000 gal/min	Drift Eliminators, Max 0.0005% DR	1.2 lb/hr	
Forsyth Energy Plant	NC	9/29/2005	Cooling Tower	3,834 gal/min		0.007 lb/hr	BACT-PSD
Forsyth Energy Plant	NC	9/29/2005	Cooling Tower	3,834 gal/min		0.002 lb/hr	BACT-PSD
Wanapa Energy Center	OR	8/8/2005	Cooling Tower	6.2 ft ³ /s	Drift Eliminators, Max 0.0005% DR	3532 ppmw	BACT-PSD
Public Serices Company of Colorado	CO	7/5/2005	Cooling Tower	140,650 gal/min	Drift Eliminators, Max 0.0005% DR		BACT-PSD
Crescent City Power	LA	6/6/2005	Main Cooling Tower	290,200 gal/min	Drift Eliminators	2.61 lb/hr	BACT-PSD
Auburn Nugget	IA	5/31/2005	Cooling Tower	290,200 gal/min	PM - 0.0050% of throughput	20 % (opacity)	BACT-PSD
Newmant Nevada Energy Investment, LLC	NV	5/5/2005	Cooling Tower		Drift Eliminators, PM ₁₀ - 0.0005% drift		BACT-PSD
Ingen-Nassau Energy Corporation	NY	3/31/2005	Cooling Tower		PM ₁₀ - 0.0005% drift		BACT-PSD
Omaha Public Power District	NE	3/9/2005	Cooling Tower			0.001 lb/hr (PM ₁₀)	BACT-PSD
BP Cherry Point Cogeneration Project	WA	1/11/2005	Cooling Tower		Drift Eliminators, Max 0.001% DR	1.64 lb/hr	BACT-PSD
Duke Energy Washington County LLC	OH	5/9/2005	Cooling Tower			2.08 lb/hr	BACT-PSD
Duke Energy Hanging Rock Energy Facility	OH	12/28/2004	(2) Cooling Tower (10 Cell Mechanical Draft)		Drift Eliminators, Max 0.001% DR	2.6 lb/hr	BACT-PSD
Chocolate Bayou Plant	TX	3/24/2003	Cooling Water Tower (2 Cells)		None Indicated	0.54 lb/hr	Other Case-by-Case
Duke Energy Stephens, LLC Stephens Energy	OK	3/21/2003	Cooling Tower		Drift Eliminators	1.2 lb/hr	BACT-PSD
Wallula Power Plant	WA	1/3/2003	Cooling Tower		Water Pretreatment, 0.0005% DR	3.7 lb/hr	Other Case-by-Case
Wallula Power Plant	WA	1/3/2003	Cooling Tower		Water Treatment, 0.0005% DR	3.7 lb/hr	LAER

Source: EPA 2010 (RBLC database); Golder, 2010

Note: DR = Drift rate

TABLE 5-1
SUMMARY OF MAXIMUM MEASURED O₃ CONCENTRATIONS IN THE VICINITY OF THE EFFINGHAM POWER PROJECT, 2007 TO 2009

						Concentration (µg/m³)								
		Monitor Location ^a				1-Hour		8-Hour						
Site No.	Location	Distance (km)	Direction (Degrees)	Measurement Period		Highest	2nd Highest	Highest	2nd Highest	3-Year Average 4th Highest				
				Year	Months									
Ozone ^b						NA	235	NA	NA	147				
13-051-0021	2500 E Presidents St. BD-A, Savannah, GA,	32	136	2009	Jan-Dec	158.9	153.0	145.2	143.2	117.0				
	Chatham County					2008	Jan-Dec	162.8	155.0	139.3	139.3	120.3		
						2007	Jan-Dec	160.9	160.9	133.4	133.4	119.7		

Note: NA = not applicable.

AAQS = ambient air quality standard.

^a Relative to Project Site.

^b On March 27, 2008, EPA promulgated revised AAQS for ozone. The O₃ standard was modified to be 0.075 ppm (147 µg/m³) for the 8-hour average; achieved when the 3-year average of 99th percentile values is 0.075 ppm or less.

Source: EPA, 2010.

TABLE 6-1
MAJOR FEATURES OF AERMOD, VERSION 09292

Model Features
<ul style="list-style-type: none"> • Plume dispersion/growth rates are determined by the profile of vertical and horizontal turbulence, vary with height, and use a continuous growth function. • In a convective atmosphere, uses three separate algorithms to describe plume behavior as it comes in contact with the mixed layer lid; in a stable atmosphere uses a mechanically mixed layer near the surface. • Polar or Cartesian coordinate systems for receptor locations can be included directly or by an external file reference. • Urban model dispersion is input as a function of city size and population density; sources can also be modeled individually as urban sources. • Stable plume rise: uses Briggs equations with winds and temperature gradients at stack top up to half-way up to plume rise. Convective plume rise: plume superimposed on random convective velocities. • Procedures suggested by Briggs (1974) for evaluating stack-tip downwash. • Has capability of simulating point, volume, area, and multi-sized area sources. • Accounts for the effects of vertical variations in wind and turbulence (Brower et al., 1998). • Uses measured and computed boundary layer parameters and similarity relationships to develop vertical profiles of wind, temperature, and turbulence (Brower et al., 1998). • Concentration estimates for 1-hour to annual average times. • Creates vertical profiles of wind, temperature, and turbulence using all available measurement levels. • Terrain features are depicted by use of a controlling hill elevation and a receptor point elevation. • Modeling domain surface characteristics are determined by selected direction and month/season values of surface roughness length, albedo, and Bowen ratio. • Contains both a mechanical and convective mixed layer height, the latter based on the hourly accumulation of sensible heat flux. • The method of Pasquill (1976) to account for buoyancy-induced dispersion. • A default regulatory option to set various model options and parameters to EPA-recommended values. • Contains procedures for calm-wind and missing data for the processing of short term averages.

Note: AERMOD = American Meteorological Society and Environmental Protection Agency Regulatory Model.

Source: USEPA, 2009; Paine et al., 2007.

TABLE 6-2
SUMMARY OF NO_x EMITTING FACILITIES IN THE VICINITY OF THE EFFINGHAM POWER PLANT (GA)

Plant ID	Facility Name	County	State	UTM Coordinates ^a		Relative to the Project ^b				Maximum PM ₁₀	Q (TPY), Emission	Include in Modeling	Cluster ^f		Include in Modeling Analysis	
				East (km)	North (km)	X (km)	Y (km)	Direction (deg.)	Distance (km)	Emissions ^c (TPY)	Threshold ^d [20 km x (Dist.-SIA)]	Analysis Based on Q? ^e	Cluster ID	Total Emissions (TPY)	Based on Q and/or Cluster?	
1	Modeling Area ^g 04-13-103-00012	Effingham Power	Effingham	GA	473.2	3571.2	-0.1	-0.1	211.7	0.2	222	SIA	YES			YES
2	Screening Area ^g 04-13-103-00015	Hth Yachts, LLC Db	Effingham	GA	476.15	3578.4	2.9	7.1	22.1	7.6	25	62.4	NO			NO
3	04-13-103-00007	Georgia-Pacific Consumer Products Lp	Effingham	GA	481.1	3577.4	7.8	6.1	52.2	9.9	4,816	107.7	YES	CL1	9,897	YES
4	04-13-103-00014	Georgia Power - Plant McIntosh Combined Cycle	Effingham	GA	482.9	3579	9.6	7.7	51.5	12.3	452	155.8	YES	CL1	9,897	YES
5	04-13-103-00003	Savannah Electric - Plant McIntosh	Effingham	GA	484.2	3580	10.9	8.7	51.6	13.9	4,630	188.6	YES	CL1	9,897	YES
6	1360-0026	SCE&G-Jasper Co. Generating Facility	Jasper	SC	488.4	3,580.1	15.1	8.7	59.9	17.4	1,564	258.3	YES	CL2	1,620	YES
7	04-13-051-00046	Gulfstream Aerospace Corp	Chatham	GA	481.9	3,556.2	8.6	-15.2	150.4	17.4	62	258.5	NO			NO
8	1360-0043	Bjwater & Sewer Authority	Jasper	SC	488.6	3,579.8	15.3	8.5	61.0	17.4	56	259.0	NO	CL2	1,620	YES
9	04-13-051-00010	Weyerhaeuser Company - Port Wentworth Mill	Chatham	GA	485.3	3,558.0	12.0	-13.3	138.0	18.0	1,757	269.2	YES	CL3	1,757	YES
10	04-13-051-00006	Georgia Power - Plant Kraft	Chatham	GA	486.3	3,556.9	13.0	-14.4	138.1	19.4	3796	298.2	YES	CL3	1,757	YES
11	1360-0012	Foster Dixiana Corporation	Jasper	SC	492.6	3,573.3	19.3	2.0	84.2	19.4	1	298.8	NO	CL4	676	NO
12	1360-0019	SCE&G-Hardeeville	Jasper	SC	492.6	3,573.3	19.3	2.0	84.2	19.4	673	298.8	YES	CL4	675.9	YES
13	04-13-051-00110	Savannah Sugar Refinery	Chatham	GA	486.1	3,556.4	12.9	-14.9	139.2	19.7	1,161	303.8	YES			YES
14	1360-0005	Carolina Castings Corporation	Jasper	SC	492.9	3,573.3	19.6	1.9	84.4	19.7	1	304.6	NO	CL4	676	NO
15	04-13-051-00205	Superior Landfill And Recycling Center	Chatham	GA	469.7	3,550.0	-3.6	-21.3	189.5	21.6	133	342.5	NO			NO
16	04-13-051-00058	Vopak Terminal Savannah, Inc.	Chatham	GA	487.5	3,553.4	14.2	-17.9	141.6	22.9	15	367.2	NO	CL5	147	NO
17	04-13-051-00132	Georgia-Pacific Corp Savannah (Shutdown)	Chatham	GA	484.1	3,550.8	10.8	-20.5	152.2	23.2	0	374.2	NO			NO
18	04-13-051-00200	Nustar Asphalt Refining (Pma Plant)	Chatham	GA	487.9	3,552.6	14.6	-18.7	142.0	23.8	9	385.6	NO	CL5	147	NO
19	04-13-051-00012	Nustar Asphalt Refining, LLC	Chatham	GA	487.9	3,552.6	14.6	-18.7	142.0	23.8	109	385.6	NO	CL5	147	YES
20	04-13-103-00004	International Paper-Wood Products (Meldrim Mill)	Effingham	GA	488.0	3,552.0	14.7	-19.3	142.7	24.3	14	396.0	NO	CL5	147	NO
21	04-13-051-00005	Hercules Incorporated	Chatham	GA	485.8	3,550.5	12.6	-20.9	149.0	24.4	65	397.2	NO			NO
22	04-13-051-00007	International Paper	Chatham	GA	488.6	3,552.0	15.3	-19.3	141.5	24.6	4,726	402.9	YES	CL5	147	YES
24	04-13-051-00148	Arizona Chemical Corp.	Chatham	GA	488.5	3,551.2	15.2	-20.1	142.9	25.2	182	414.1	NO	CL6	241	YES
25	04-13-051-00076	Colonial Terminals, Inc. Plant 1	Chatham	GA	489.4	3,550.9	16.1	-20.5	141.8	26.1	23	431.2	NO	CL6	241	NO
26	04-13-051-00032	Great Dane Trailers Savannah	Chatham	GA	489.4	3,549.3	16.1	-22.1	143.9	27.3	8	456.8	NO	CL6	241	NO
27	04-13-051-00037	Emd Chemicals Inc	Chatham	GA	490.5	3,549.7	17.2	-21.6	141.5	27.6	15	462.8	NO	CL6	241	NO
28	04-13-051-00018	Savannah Electric - Plant Riverside	Chatham	GA	491.1	3,549.6	17.8	-21.7	140.6	28.1	7	471.9	NO	CL6	241	NO
29	04-13-051-00077	Southern States Phosphate & Fertilizer	Chatham	GA	493.9	3,548.4	20.7	-23.0	138.0	30.9	7	527.7	NO	CL6	241	NO
30	04-13-051-00017	Georgia Power - Boulevard	Chatham	GA	488.6	3,544.4	15.3	-27.0	150.4	31.0	1	530.0	NO			NO
31	04-13-051-00023	Basf Catalysts LLC	Chatham	GA	494.2	3,548.3	21.0	-23.0	137.7	31.1	206	532.8	NO	CL7	230	NO
32	04-13-051-00019	G-P Gypsum Corp. - Savannah Plant	Chatham	GA	495.1	3,548.8	21.8	-22.6	136.0	31.4	24	537.3	NO	CL7	230	NO
33	04-13-051-00176	St Services - Woodcock Rd	Chatham	GA	496.4	3,549.1	23.1	-22.2	133.8	32.1	22	551.8	NO	CL8	112	NO
34	04-13-051-00008	Tronox Pigments (Savannah) Inc	Chatham	GA	497.5	3,549.4	24.2	-21.9	132.2	32.7	90	563.6	NO	CL8	112	NO
35	1360-0037	Coastal Debris	Jasper	SC	502.2	3,589.7	28.9	18.3	57.6	34.2	105	594.8	NO			NO
36	04-13-051-00003	El Paso Energy/Southern Lng Inc.	Chatham	GA	500.3	3,550.0	27.1	-21.3	128.3	34.5	163	599.3	NO			NO
37	1360-0021	Hickory Hill Landfill & Recycling	Jasper	SC	506.8	3,584.3	33.5	12.9	68.9	35.9	4	627.8	NO			NO
38	04-13-031-00005	W.M. Sheppard Lumber Co Inc	Bulloch	GA	437.6	3,582.7	-35.7	11.3	287.6	37.5	10	659.1	NO			NO
40	0360-0046	Resort Services, Inc.	Beaufort	SC	511.5	3,567.3	38.2	-4.1	96.1	38.4	81	678.1	NO	CL9	391	NO
41	1360-0036	Wasteco	Jasper	SC	509.4	3,587.9	36.1	16.5	65.4	39.7	110	704.2	NO			NO
42	0360-0050	Beaufort-Jasper Water & Sewage	Beaufort	SC	512.3	3,581.0	39.1	9.7	76.1	40.2	376	714.8	NO			NO
43	0360-0031	Ulmer Brothers Inc.	Beaufort	SC	513.7	3,566.1	40.4	-5.3	97.4	40.7	77	724.3	NO	CL9	391	NO
44	0360-0037	Malphrus Construction Co.	Beaufort	SC	515.0	3,567.2	41.7	-4.2	95.7	41.9	82	748.1	NO	CL9	391	NO
45	0360-0066	Daufuskie Island P&H Inc.	Beaufort	SC	511.3	3,552.7	38.0	-18.6	116.1	42.3	123	756.5	NO			NO
46	0360-0068	Target Store 1298	Beaufort	SC	515.7	3,568.2	42.4	-3.2	94.3	42.5	75	760.6	NO	CL9	391	NO
47	1280-0025	Federal Corrections Institute	Hampton	SC	475.9	3,620.2	2.6	48.9	3.0	49.0	29	889.0	NO			NO
48	04-13-031-00028	Claude Howard Lumber Co. Inc.	Bulloch	GA	427.0	3,589.1	-46.3	17.8	291.0	49.6	51	901.7	NO			NO
49	1280-0004	Elliot Sawmilling Co.	Hampton	SC	477.1	3,621.1	3.8	49.8	4.4	49.9	141	908.2	NO			NO
50	0360-0051	SIPSD (Reclaimed Water Plant)	Beaufort	SC	521.0	3,555.0	47.7	-16.4	108.9	50.5	149	919.0	NO	CL10	265	NO
51	0360-0061	SIPSD Reverse Osmosis Plant	Beaufort	SC	523.1	3,556.7	49.8	-14.6	106.3	51.9	116	948.7	NO	CL10	265	NO
52	0360-0053	Hilton Head #1 - Royal James Drive Facility	Beaufort	SC	525.1	3,567.1	51.8	-4.3	94.7	52.0	54	950.2	NO			NO
53	1280-0033	Carolina Soya	Hampton	SC	476.6	3,623.4	3.3	52.1	3.6	52.2	107	953.4	NO			NO
54	0360-0070	Beaufort-Jasper Water & Sewer	Beaufort	SC	523.8	3,585.0	50.5	13.6	74.9	52.3	272	955.9	NO			NO
55	04-13-251-00008	King America Finishing, Inc.	Screven	GA	432.9	3,604.6	-40.4	33.3	309.5	52.4	150	957.0	NO			NO

TABLE 6-2
SUMMARY OF NO_x EMITTING FACILITIES IN THE VICINITY OF THE EFFINGHAM POWER PLANT (GA)

Plant ID	Facility Name	County	State	UTM Coordinates ^a		Relative to the Project ^b				Maximum PM ₁₀ Emissions ^c (TPY)	Q (TPY), Emission Threshold ^d [20 km x (Dist.-SIA)]	Include in Modeling Analysis Based on Q? ^e	Cluster ^f		Include in Modeling Analysis Based on Q and/or Cluster?
				East (km)	North (km)	X (km)	Y (km)	Direction (deg.)	Distance (km)				Cluster ID	Total Emissions (TPY)	
56	04-13-051-00149	Hunter Army Airfield	Chatham	GA	445.7	3,526.4	-27.5	-44.9	211.5	52.7	4	964.3	NO		NO
57	0360-0021	Hilton Head Hospital	Beaufort	SC	526.5	3,565.0	53.2	-6.3	96.8	53.6	13	981.8	NO	CL11	5,941
58	0360-0052	Hilton Head #1 - Leg-O-Mutton Road Well	Beaufort	SC	527.0	3,563.5	53.7	-7.9	98.3	54.3	23	995.0	NO	CL11	5,941
Beyond Screening Area ^g															
59	0360-0044	Hilton Head No. 1 Public Service District	Beaufort	SC	528.3	3,563.8	55.0	-7.5	97.8	55.5	133	1,020.9	NO	CL11	5,941
60	0360-0006	Santee Cooper - Hilton Head	Beaufort	SC	528.3	3,563.5	55.0	-7.9	98.2	55.6	5,772	1,022.1	YES	CL11	5,941
61	0360-0048	SCE&G - Burton Gas Turbine	Beaufort	SC	526.2	3,588.6	52.9	17.3	71.9	55.7	1,709	1,023.7	YES		
62	0360-0005	US Naval Hospital	Beaufort	SC	523.4	3,596.8	50.1	25.4	63.1	56.2	28	1,033.1	NO		
63	0360-0004	US Marines Corps Air Station	Beaufort	SC	525.8	3,592.6	52.5	21.3	67.9	56.7	1,424	1,043.8	YES		
64	0360-0002	US Marines-MCRD Parris Island	Beaufort	SC	529.6	3,578.2	56.3	6.9	83.0	56.7	488	1,044.9	NO		
65	04-13-179-00018	Fort Stewart Hqs 3d Infantry Div (Mech)	Liberty	GA	441.4	3,523.6	-31.9	-47.7	213.8	57.4	87	1,058.1	NO		
66	0360-0049	Beaufort Memorial Hospital	Beaufort	SC	529.5	3,586.5	56.2	15.2	74.9	58.2	15	1,074.4	NO		
67	0360-0012	Armaz Custom Chemicals	Beaufort	SC	525.4	3,601.9	52.1	30.5	59.6	60.4	21	1,117.5	NO		
68	04-13-179-00001	Interstate Paper LLC	Liberty	GA	461.5	3,511.7	-11.8	-59.6	191.2	60.8	677	1,125.5	NO	CL12	852
69	04-13-179-00011	Snf Holding Company - Riceboro, Ga	Liberty	GA	459.0	3,512.0	-14.3	-59.3	193.5	61.0	175	1,130.1	NO	CL12	852
70	04-13-109-00008	Georgia-Pacific Corp Chip-N-Saw Div	Evans	GA	409.6	3,557.6	-63.7	-13.7	257.9	65.2	83	1,213.7	NO		
71	1280-0008	Georgia Pacific	Hampton	SC	494.3	3,633.6	21.0	62.2	18.7	65.7	45	1,223.4	NO		
72	1280-0001	Nevamar	Hampton	SC	489.5	3,637.4	16.2	66.1	13.8	68.0	527	1,270.5	NO		
73	0160-0015	Fairfax Dimension Co., Inc.	Allendale	SC	476.4	3,647.6	3.2	76.2	2.4	76.3	15	1,435.5	NO	CL13	862
74	0160-0020	Grant Allendale LP	Allendale	SC	479.0	3,650.6	5.7	79.2	4.1	79.4	847	1,498.8	NO	CL13	862
75	0160-0004	Collum's Lumber Mill	Allendale	SC	470.7	3,653.3	-2.6	82.0	358.2	82.0	113	1,550.6	NO		
76	0160-0006	Clariant Corporation	Allendale	SC	455.0	3,655.3	-18.3	84.0	347.7	85.9	88	1,628.6	NO		
77	04-13-305-00001	Rayonier Performance Fibers, LLC - Jesup Mill	Wayne	GA	419.5	3,503.1	-53.7	-68.2	218.2	86.8	1,501	1,646.7	NO		
78	0160-0007	Mohawk Industries	Allendale	SC	481.1	3,662.5	7.8	91.2	4.9	91.5	32	1,739.9	NO		

a UTM coordinates based on Title V inventory, PSD inventory, or modeling files from Georgia EPD and on data provided by SC DHEC. Coordinates verified for sources in Effingham County.

b The Project is located at approximate UTM coordinates:
East 473.3 km
North 3,571.3 km

c Maximum emissions based on initial information from Georgia EPD using actual emissions from B3 - Facility-Wide Actual Emissions Estimates and using short-term emission rates provided by SC DHEC. Source were reviewed for potential emissions based on Title V applications available from Georgia EPD website or data obtained from the facility (e.g., Georgia Pacific).

d The modeling area or significant impact area (SIA) for the project is estimated to be 4.5 km

e Based on the North Carolina Screening Threshold method, a background facility is included in the modeling analysis if the facility is within the modeling area and its emission rate is greater than the product of "20 km x (Distance - SIA)".

f Clusters included facilities within approximately 2 to 3 degrees and 2 to 3 km of each other. The Emission Threshold, Q, for the cluster based on facility within the cluster that was nearest to the project. Facility included in a cluster and modeled if emissions are greater than 10 TPY and located within 10 km of project; emissions greater than 25 TPY and located beyond 10 km from project.

g "Modeling Area" is the area in which the Project is predicted to have a significant impact. EPA recommends that all sources within this area be modeled.
"Screening Area" is the area that is 50 km beyond the modeling area. EPA recommends that sources be modeled that are expected to have a significant impact in the modeling area.
"Beyond Screening Area" is the area beyond the screening area and out to 100 km in which only large sources are included in the modeling.

TABLE 6-3
SUMMARY OF PM₁₀ EMITTING FACILITIES IN THE VICINITY OF THE EFFINGHAM POWER PLANT (GA)

Plant Facility ID Name	County	State	UTM Coordinates ^a		Relative to the Project ^b				Maximum PM ₁₀ Emissions ^c (TPY)	Q (TPY), Emission Threshold ^d [20 km x (Dist.-SIA)]	Include in Modeling Analysis Based on Q? ^e	Cluster ^f		Include in Modeling Analysis Based on Q and/or Cluster?	
			East (km)	North (km)	X (km)	Y (km)	Direction (deg.)	Distance (km)				Cluster ID	Total Emissions (TPY)		
1	Modeling Area ^g 04-13-103-00012 Effingham Power	Effingham	GA	473.2	3571.2	-0.1	-0.1	211.7	0.2	92	SIA	YES		YES	
2	Screening Area ^g 04-13-103-00007 Georgia-Pacific Consumer Products Lp	Effingham	GA	481.1	3,577.4	7.8	6.1	52.2	9.9	497	157.7	YES	CL1	2,859	YES
3	04-13-103-00014 Georgia Power - Plant McIntosh Combined Cycle	Effingham	GA	482.9	3,579.0	9.6	7.7	51.5	12.3	297	205.8	YES	CL1	2,859	YES
4	04-13-103-00003 Savannah Electric - Plant McIntosh	Effingham	GA	484.2	3,580.0	10.9	8.7	51.6	13.9	2,065	238.6	YES	CL1	2,859	YES
5	1360-0026 SCE&G-Jasper Co. Generating Facility	Jasper	SC	488.4	3,580.1	15.1	8.7	59.9	17.4	715	308.3	YES	CL2	923	YES
6	04-13-051-00046 Gulfstream Aerospace Corp	Chatham	GA	481.9	3,556.2	8.6	-15.2	150.4	17.4	4	308.5	NO			NO
7	1360-0043 Bjwater & Sewer Authority	Jasper	SC	488.6	3,579.8	15.3	8.5	61.0	17.4	208	309.0	NO	CL2	923	NO
8	04-13-103-00004 International Paper-Wood Products (Meldrim Mill)	Effingham	GA	463.5	3556.6	-9.8	-14.7	213.6	17.7	91	313.9	NO			NO
9	04-13-051-00010 Weyerhaeuser Company - Port Wentworth Mill	Chatham	GA	485.3	3,558.0	12.0	-13.3	138.0	18.0	657	319.2	YES	CL3	5,881	YES
10	04-13-051-00006 Georgia Power - Plant Kraft	Chatham	GA	486.3	3,556.9	13.0	-14.4	138.1	19.4	4,815	348.2	YES	CL3	5,881	YES
11	1360-0019 SCE&G-Hardeeville	Jasper	SC	492.6	3,573.3	19.3	2.0	84.2	19.4	59	348.8	NO	CL4	72	NO
12	04-13-051-00110 Savannah Sugar Refinery	Chatham	GA	486.1	3,556.4	12.9	-14.9	139.2	19.7	410	353.8	YES	CL3	5,881	YES
13	1360-0005 Carolina Castings Corporation	Jasper	SC	492.9	3,573.3	19.6	1.9	84.4	19.7	13	354.6	NO	CL4	72	NO
14	04-13-051-00205 Superior Landfill And Recycling Center	Chatham	GA	469.7	3,550.0	-3.6	-21.3	189.5	21.6	15	392.5	NO			NO
15	04-13-051-00132 Georgia-Pacific Corp Savannah (Shutdown)	Chatham	GA	484.1	3,550.8	10.8	-20.5	152.2	23.2	0	424.2	NO			NO
16	04-13-051-00012 Nustar Asphalt Refining, LLC	Chatham	GA	487.9	3,552.6	14.6	-18.7	142.0	23.8	347	435.6	NO	CL5	1,455	YES
17	04-13-051-00005 Hercules Incorporated	Chatham	GA	485.8	3,550.5	12.6	-20.9	149.0	24.4	35	447.2	NO			NO
18	04-13-051-00007 International Paper	Chatham	GA	488.6	3,552.0	15.3	-19.3	141.5	24.6	971	452.9	YES	CL5	1,455	YES
19	04-13-051-00148 Arizona Chemical Corp.	Chatham	GA	488.5	3,551.2	15.2	-20.1	142.9	25.2	13	464.1	NO	CL5		NO
20	04-13-051-00210 Dean Forest Road Landfill	Chatham	GA	480.2	3,546.9	6.9	-24.4	164.3	25.4	5	467.8	NO			NO
21	04-13-051-00076 Colonial Terminals, Inc. Plant 1	Chatham	GA	489.4	3,550.9	16.1	-20.5	141.8	26.1	111	481.2	NO	CL5	1,455	YES
22	04-13-051-00032 Great Dane Trailers Savannah	Chatham	GA	489.4	3,549.3	16.1	-22.1	143.9	27.3	6	506.8	NO	CL5	1,455	NO
23	04-13-051-00037 Emd Chemicals Inc	Chatham	GA	490.5	3,549.7	17.2	-21.6	141.5	27.6	7	512.8	NO	CL5	1,455	NO
24	04-13-051-00023 Basf Catalysts LLC	Chatham	GA	494.2	3,548.3	21.0	-23.0	137.7	31.1	144	582.8	NO	CL6	370	NO
25	04-13-051-00019 G-P Gypsum Corp. - Savannah Plant	Chatham	GA	495.1	3,548.8	21.8	-22.6	136.0	31.4	150	587.3	NO	CL6	226	NO
26	04-13-051-00008 Tronox Pigments (Savannah) Inc	Chatham	GA	496.8	3,548.8	23.5	-22.5	133.8	32.5	76	610.3	NO	CL6	226	NO
27	1360-0037 Coastal Debris	Jasper	SC	502.2	3,589.7	28.9	18.3	57.6	34.2	130	644.8	NO			NO
28	04-13-051-00003 El Paso Energy/Southern Lng Inc.	Chatham	GA	500.3	3,550.0	27.1	-21.3	128.3	34.5	3	649.3	NO			NO
29	04-13-031-00005 W.M. Sheppard Lumber Co Inc	Bulloch	GA	437.6	3,582.7	-35.7	11.3	287.6	37.5	31	709.1	NO			NO
30	0360-0046 Resort Services, Inc.	Beaufort	SC	511.5	3,567.3	38.2	-4.1	96.1	38.4	23	728.1	NO	CL7	479	NO
31	1360-0036 Wasteco	Jasper	SC	509.4	3,587.9	36.1	16.5	65.4	39.7	135	754.2	NO			NO
32	0360-0050 Beaufort-Jasper Water & Sewage	Beaufort	SC	512.3	3,581.0	39.1	9.7	76.1	40.2	7	764.8	NO			NO
33	0360-0031 Ulmer Brothers Inc.	Beaufort	SC	513.7	3,566.1	40.4	-5.3	97.4	40.7	249	774.3	NO	CL7	479	NO
34	0360-0037 Malphrus Construction Co.	Beaufort	SC	515.0	3,567.2	41.7	-4.2	95.7	41.9	95	798.1	NO	CL7	479	NO
35	0360-0066 Daufuskie Island P&H Inc.	Beaufort	SC	511.3	3,552.7	38.0	-18.6	116.1	42.3	151	806.5	NO			NO
36	1280-0025 Federal Corrections Institute	Hampton	SC	475.9	3,620.2	2.6	48.9	3.0	49.0	12	939.0	NO			NO
37	04-13-031-00028 Claude Howard Lumber Co. Inc.	Bulloch	GA	427.0	3,589.1	-46.3	17.8	291.0	49.6	51	951.7	NO			NO
38	1280-0004 Elliot Sawmilling Co.	Hampton	SC	477.1	3,621.1	3.8	49.8	4.4	49.9	24	958.2	NO			NO
39	0360-0051 SIPSD (Reclaimed Water Plant)	Beaufort	SC	521.0	3,555.0	47.7	-16.4	108.9	50.5	3	969.0	NO	CL8	8	NO
40	0360-0061 SIPSD Reverse Osmosis Plant	Beaufort	SC	523.1	3,556.7	49.8	-14.6	106.3	51.9	5	998.7	NO	CL8	8	NO
41	0360-0053 Hilton Head #1 - Royal James Drive Facility	Beaufort	SC	525.1	3,567.1	51.8	-4.3	94.7	52.0	5	1,000.2	NO			NO

TABLE 6-3
SUMMARY OF PM₁₀ EMITTING FACILITIES IN THE VICINITY OF THE EFFINGHAM POWER PLANT (GA)

Plant Facility ID Name	County	State	UTM Coordinates ^a		Relative to the Project ^b				Maximum PM ₁₀ Emissions ^c (TPY)	Q (TPY), Emission Threshold ^d [20 km x (Dist.-SIA)]	Include in Modeling Analysis Based on Q? ^e	Cluster ^f		Include in Modeling Analysis Based on Q and/or Cluster?		
			East (km)	North (km)	X (km)	Y (km)	Direction (deg.)	Distance (km)				Cluster ID	Total Emissions (TPY)			
Beyond Screening Area ^g																
43	1280-0033	Carolina Soya	Hampton	SC	476.6	3,623.4	3.3	52.1	3.6	52.2	98	1,003.4	NO		NO	
44	04-13-251-00008	King America Finishing, Inc.	Screven	GA	432.9	3,604.6	-40.4	33.3	309.5	52.4	40	1,007.0	NO		NO	
45	0360-0006	Santee Cooper - Hilton Head	Beaufort	SC	528.3	3,563.5	55.0	-7.9	98.2	55.6	314	1,072.1	NO		NO	
46	0360-0048	SCE&G - Burton Gas Turbine	Beaufort	SC	526.2	3,588.6	52.9	17.3	71.9	55.7	166	1,073.7	NO	CL9	492	NO
47	0360-0005	US Naval Hospital	Beaufort	SC	523.4	3,596.8	50.1	25.4	63.1	56.2	22	1,083.1	NO			NO
48	0360-0004	US Marines Corps Air Station	Beaufort	SC	525.8	3,592.6	52.5	21.3	67.9	56.7	325	1,093.8	NO	CL9	492	NO
49	0360-0002	US Marines-MCRD Parris Island	Beaufort	SC	529.6	3,578.2	56.3	6.9	83.0	56.7	212	1,094.9	NO	CL10	252	NO
50	0360-0056	SC State Port Authority	Beaufort	SC	529.3	3,581.5	56.0	10.2	79.7	56.9	39	1,098.7	NO	CL10	252	NO
51	04-13-179-00018	Fort Stewart Hqs 3d Infantry Div (Mech)	Liberty	GA	441.4	3,523.6	-31.9	-47.7	213.8	57.4	27	1,108.1	NO			NO
52	04-13-179-00001	Interstate Paper LLC	Liberty	GA	461.5	3,511.7	-11.8	-59.6	191.2	60.8	227	1,175.5	NO	CL11	310	NO
53	04-13-179-00011	Snf Holding Company - Riceboro, Ga	Liberty	GA	459.0	3,512.0	-14.3	-59.3	193.5	61.0	83	1,180.1	NO	CL11	310	NO
54	04-13-109-00008	Georgia-Pacific Corp Chip-N-Saw Div	Evans	GA	409.6	3,557.6	-63.7	-13.7	257.9	65.2	89	1,263.7	NO			NO
55	1280-0008	Georgia Pacific	Hampton	SC	494.3	3,633.6	21.0	62.2	18.7	65.7	162	1,273.4	NO			NO
56	1280-0001	Nevamar	Hampton	SC	489.5	3,637.4	16.2	66.1	13.8	68.0	255	1,320.5	NO			NO
57	0160-0015	Fairfax Dimension Co., Inc.	Allendale	SC	476.4	3,647.6	3.2	76.2	2.4	76.3	20	1,485.5	NO	CL12	620	NO
58	0160-0020	Grant Allendale LP	Allendale	SC	479.0	3,650.6	5.7	79.2	4.1	79.4	600	1,548.8	NO	CL12	620	NO
59	0160-0004	Collum's Lumber Mill	Allendale	SC	470.7	3,653.3	-2.6	82.0	358.2	82.0	127	1,600.6	NO			NO
60	0160-0006	Clariant Corporation	Allendale	SC	455.0	3,655.3	-18.3	84.0	347.7	85.9	62	1,678.6	NO			NO
61	04-13-305-00001	Rayonier Performance Fibers, LLC - Jesup Mill	Wayne	GA	419.5	3,503.1	-53.7	-68.2	218.2	86.8	608	1,696.7	NO			NO
62	0160-0007	Mohawk Industries	Allendale	SC	481.1	3,662.5	7.8	91.2	4.9	91.5	48	1,789.9	NO			NO

^a UTM coordinates based on Title V inventory, PSD inventory, or modeling files from Georgia EPD and on data provided by SC DHEC. Coordinates verified for sources in Effingham County.

^b The Project is located at approximate UTM coordinates:

East	473.3	km
North	3,571.3	km

^c Maximum emissions based on initial information from Georgia EPD using actual emissions from B3 - Facility-Wide Actual Emissions Estimates and using short-term emission rates provided by SC DHEC. Source were reviewed for potential emissions based on Title V applications available from Georgia EPD website or data obtained from the facility (e.g., Georgia Pacific).

^d The modeling area or significant impact area (SIA) for the project is estimated to be 2.0 km

^e Based on the North Carolina Screening Threshold method, a background facility is included in the modeling analysis if the facility is within the modeling area and its emission rate is greater than the product of "20 km x (Distance - SIA)".

^f Clusters included facilities within approximately 2 to 3 degrees and 2 to 3 km of each other. The Emission Threshold, Q, for the cluster based on facility within the cluster that was nearest to the project. Facility included in a cluster and modeled if emissions are greater than 10 TPY and located within 10 km of project; emissions greater than 25 TPY and located beyond 10 km from project.

^g "Modeling Area" is the area in which the Project is predicted to have a significant impact. EPA recommends that all sources within this area be modeled. "Screening Area" is the area that is 50 km beyond the modeling area. EPA recommends that sources be modeled that are expected to have a significant impact in the modeling area. "Beyond Screening Area" is the area beyond the screening area and out to 100 km in which only large sources are included in the modeling.



TABLE 6-4
SUMMARY OF BUILDING DIMENSIONS USED FOR THE MODELING ANALYSIS
FOR THE EFFINGHAM POWER PLANT

Building Description	Height		Length		Width	
	(ft)	(m)	(ft)	(m)	(ft)	(m)
<u>Existing Buildings</u>						
Heat Recovery Steam Gen. No. 1	90.0	27.4	71.2	21.7	47.7	14.5
Heat Recovery Steam Gen. No. 2	90.0	27.4	71.2	21.7	47.7	14.5
Cooling Tower	33.0	10.1	480.0	146.3	48.0	14.6
Steam Turbine	59.0	18.0	112.3	34.2	40.9	12.5
<u>Future Buildings</u>						
Heat Recovery Steam Gen. No. 1	90.0	27.4	71.2	21.7	47.7	14.5
Heat Recovery Steam Gen. No. 2	90.0	27.4	71.2	21.7	47.7	14.5
Cooling Tower	33.0	10.1	480.0	146.3	48.0	14.6
Steam Turbine	59.0	18.0	172.6	52.6	75.9	23.1

TABLE 6-5
DETERMINATION OF ACCEPTABLE AMBIENT CONCENTRATION OF HAZARDOUS AND TOXIC AIR POLLUTANTS
EFFINGHAM POWER EXPANSION PROJECT

Pollutant	CAS No.	Step 1: Toxicity Data ^a						Step 2: Adjustment of Toxicity Data		Step 3: Application of Safety Factor		Step 4: Determine AAC		
		Integrated Risk Information System (IRIS)						Basis of Toxicity	Adjustment (mg/m ³)	Safety Factor	Safety Adjusted (mg/m ³)	AAC (µg/m ³)	Basis	Averaging Period
		Unit Risk (per µg/m ³)	Cancer Risk	RBAC (µg/m ³)	IRIS RfC (mg/m ³)	OSHA PEL (mg/m ³)	ACGIH TLV (mg/m ³)							
1,3-Butadiene	106-99-0	--	--	--	2.00E-03	--	--	RfC	None	None	None	2.00	RfC	Annual
Acetaldehyde	75-07-0	2.20E-06	1/100,000	4.55E+00	9.00E-03	--	--	RBAC	None	None	None	4.55	RBAC	Annual
Acrolein	107-02-8	--	--	--	2.00E-05	--	--	RfC	None	None	None	0.02	RfC	Annual
Ammonia	7664-41-7	--	--	--	1.00E-01	--	--	RfC	None	None	None	100	RfC	Annual
Arsenic		0.0043	1/1,000,000	2.33E-04	--	--	--	RBAC	None	None	None	2.33E-04	RBAC	Annual
Benzene	71-43-2	7.80E-06	1/1,000,000	1.28E-01	3.00E-02	--	--	RBAC	None	None	None	0.13	RBAC	Annual
Beryllium		2.40E-03	1/100,000	4.17E-03	2.00E-02	--	--	RBAC	None	None	None	0.0042	RBAC	Annual
Cadmium		1.80E-03	1/100,000	5.56E-03	--	--	--	RBAC	None	None	None	0.0056	RBAC	Annual
Chromium		--	--	--	--	1	--	OSHA PEL	0.2381	300	0.00079	0.8	OSHA PEL	24-Hour
Cobalt		--	--	--	--	0.1	--	OSHA PEL	0.0238	300	0.00008	0.1	OSHA PEL	24-Hour
Ethylbenzene	100-41-4	--	--	--	1.00E+00	--	--	RfC	None	None	None	1000	RfC	Annual
Formaldehyde	50-00-0	1.30E-05	1/100,000	7.69E-01	--	--	--	RBAC	None	None	None	0.77	RBAC	Annual
n-Hexane	110-54-3	--	--	--	7.00E-01	--	--	RfC	None	None	None	700	RfC	Annual
Lead-Total		--	--	--	--	--	0.50	ACGIH	0.1190	300	3.97E-04	0.4	ACGIH	24-Hour
Manganese		--	--	--	5.00E-05	--	--	RfC	None	None	None	0.05	RfC	Annual
Mercury		--	--	--	3.00E-04	--	--	RfC	None	None	None	0.30	RfC	Annual
Nickel ^b		2.40E-04	1/1,000,000	4.17E-03	--	--	--	RBAC	None	None	None	4.17E-03	RBAC	Annual
Propylene oxide	75-56-9	--	--	--	3.00E-02	--	--	RfC	None	None	None	30	RfC	Annual
Selenium		--	--	--	--	0.2	--	OSHA PEL	0.0476	300	0.00016	0.2	OSHA PEL	24-Hour
Toluene	108-88-3	--	--	--	5.00E+00	--	--	RfC	None	None	None	5000	RfC	Annual
Xylenes	1330-20-7	--	--	--	1.00E-01	--	--	RfC	None	None	None	100	RfC	Annual
Polycyclic Organic Matters (POMs)														
Acenaphthene	83-32-9	--	--	--	--	--	--							
Acenaphthylene	208-96-8	--	--	--	--	--	--							
Anthracene	120-12-7	--	--	--	--	0.2	--	OSHA PEL	0.0476	300	0.00016	0.16	OSHA PEL	24-Hour
Benzo(a)anthracene	56-55-3	--	--	--	--	--	--							
Benzo(b)fluoranthene	205-99-2	--	--	--	--	--	--							
Benzo(k)fluoranthene	207-08-9	--	--	--	--	--	--							
Benzo(g,h,i)perylene	191-24-2	--	--	--	--	--	--							
Benzo(a)pyrene	50-32-8	--	--	--	--	0.2	--	OSHA PEL	0.0476	300	0.00016	0.16	OSHA PEL	24-Hour
Chrysene	218-01-9	--	--	--	--	0.2	--	OSHA PEL	0.0476	300	0.00016	0.16	OSHA PEL	24-Hour
Dibenzo(a,h)anthracene	53-70-3	--	--	--	--	--	--							
Fluoranthene	206-44-0	--	--	--	--	--	--							
Fluorene	86-73-7	--	--	--	--	0.2	--	OSHA PEL	0.0476	300	0.00016	0.16	OSHA PEL	24-Hour
Indeno(1,2,3-cd)pyrene	193-39-5	--	--	--	--	--	--							
3 - Methylchloranthrene	56-49-5	--	--	--	--	--	--							
2 - Methylnapthalene	91-57-6	--	--	--	--	--	--							
Naphthalene	91-20-3	--	--	--	3.00E-03	--	--	RfC	None	None	None	3	RfC	Annual
Phenanthrene	85-01-8	--	--	--	--	0.2	--	OSHA PEL	0.0476	300	0.00016	0.16	OSHA PEL	24-Hour
Pyrene	129-00-0	--	--	--	--	0.2	--	OSHA PEL	0.0476	300	0.00016	0.16	OSHA PEL	24-Hour
Total POMs ^c												0.16		24-Hour

PEL = Permissible Exposure Limit, RBAC = Risk Based Air Concentration, RfC = Inhalation Reference Concentration, REL = Recommended Exposure Limit, AAC = Acceptable Ambient Concentration, TLV = Threshold Limiting Value.

^a Toxicity data obtained from EPA's Integrated Risk Information System (IRIS) database, or the Occupational Safety and Health Administration's (OSHA) Permissible Exposure Limit (PEL) standards, or the American Conference of Governmental and Industrial Hygienist's (ACGIH) Threshold Limiting Values (TLV) per the instructions of the Georgia Department of Natural Resources' Guideline for Ambient Impact Assessment of Toxic Air Pollutant Emissions (revised June 21, 1998).

^b Nickel refinery dust from IRIS.

^c AAC is set equal to the worst-case AAC of the available AACs within the POM group.

TABLE 6-6
MAXIMUM CONCENTRATIONS PREDICTED FOR THE LOAD ANALYSIS OF THE TWO CTS FIRING NATURAL GAS AND FUEL OIL
IN COMBINED-CYCLE OPERATION AT THE PROJECT VICINITY (SAVANNAH LAND USE)

Pollutant	Maximum Emission Rates [g/s (lb/hr)] by Operating Load and Air Temperature										Averaging Time	Maximum Predicted Concentrations (ug/m ³) by Operating Load and Air Temperature ^a									
	Base Load - DB				75% Load			50% Load				Base Load - DB				75% Load			50% Load		
	20°F	59°F	95°F	95°F - IC	20°F	59°F	95°F	20°F	59°F	95°F		20°F	59°F	95°F	95°F - IC	20°F	59°F	95°F	20°F	59°F	95°F
	Case 5	Case 6	Case 7	Case 8	Case 9	Case 10	Case 11	Case 12	Case 13	Case 14		Case 5	Case 6	Case 7	Case 8	Case 9	Case 10	Case 11	Case 12	Case 13	Case 14
<u>Natural Gas</u>																					
Generic ^b	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	Annual	0.26	0.28	0.30	0.28	0.33	0.33	0.34	0.44	0.44	0.44
											24-Hour	2.31	2.44	2.61	2.45	2.93	2.93	3.10	4.02	4.08	4.14
											8-Hour	5.94	6.39	7.02	6.40	7.89	7.89	8.24	10.01	10.12	10.26
											3-Hour	7.32	7.73	8.22	7.73	8.94	8.94	9.31	11.32	11.42	11.61
											1-Hour	11.86	12.70	13.75	12.72	15.09	15.08	15.60	18.05	18.17	18.29
PM ₁₀ /PM _{2.5}	3.4	3.4	3.4	3.4	2.4	2.4	2.4	2.4	2.4	2.4	Annual	0.089	0.094	0.101	0.094	0.080	0.079	0.082	0.1050	0.1053	0.1054
	(27.2)	(27.1)	(26.9)	(27.1)	(19.2)	(19.1)	(19.0)	(18.9)	(18.9)	(18.8)	24-Hour	0.79	0.83	0.89	0.83	0.71	0.70	0.74	0.96	0.97	0.98
NO _x	7.3	6.9	6.6	6.9	3.8	3.5	3.2	3.0	2.8	2.6	Annual	0.19	0.192	0.196	0.192	0.126	0.116	0.111	0.132	0.125	0.115
	(57.6)	(55.1)	(52.0)	(55.1)	(30.2)	(27.8)	(25.7)	(23.8)	(22.3)	(20.5)	1-Hour	8.61	8.82	9.01	8.84	5.73	5.29	5.06	5.41	5.11	4.73
CO	13.3	13.1	12.8	13.1	2.8	2.6	2.4	2.2	2.1	1.9	8-Hour	7.92	8.37	9.00	8.38	2.19	2.02	1.95	2.19	2.08	1.94
	(105.8)	(104.0)	(101.7)	(104.0)	(22.0)	(20.3)	(18.8)	(17.4)	(16.3)	(15.0)	1-Hour	15.80	16.64	17.61	16.67	4.19	3.86	3.69	3.95	3.73	3.46
	Base Load - DB			75% Load			50% Load			Base Load - DB			75% Load			50% Load					
	20°F	59°F	95°F	20°F	59°F	95°F	20°F	59°F	95°F	20°F	59°F	95°F	20°F	59°F	95°F	20°F	59°F	95°F	20°F	59°F	95°F
	Case 18	Case 19	Case 20	Case 21	Case 22	Case 23	Case 24	Case 25	Case 26	Case 18	Case 19	Case 20	Case 21	Case 22	Case 23	Case 24	Case 25	Case 26	Case 24	Case 25	Case 26
<u>Fuel Oil</u>																					
Generic ^b	10.00	10.00	10.00		10.00	10.00	10.00	10.00	10.00	10.00	Annual	0.17	0.18	0.20		0.24	0.24	0.25	0.30	0.30	0.30
											24-Hour	1.58	1.70	1.84		2.19	2.22	2.25	2.80	2.82	2.84
											8-Hour	4.19	4.49	5.00		6.07	6.22	6.38	7.66	7.70	7.76
											3-Hour	5.00	5.35	5.79		6.93	7.10	7.27	8.69	8.73	8.79
											1-Hour	8.93	9.52	10.27		12.26	12.46	12.67	14.50	14.55	14.61
PM ₁₀ /PM _{2.5}	4.62	4.60	4.58		4.46	4.45	4.44	4.42	4.41	4.40	Annual	0.077	0.082	0.089		0.11	0.11	0.11	0.1320	0.1320	0.132
	(36.6)	(36.5)	(36.3)		(35.4)	(35.3)	(35.2)	(35.1)	(35.0)	(34.9)	24-Hour	0.73	0.78	0.84		0.98	0.99	1.00	1.24	1.24	1.25
NO _x	22.7	21.5	19.6		16.7	15.7	14.3	12.9	12.3	11.1	Annual	0.38	0.38	0.38		0.40	0.38	0.35	0.39	0.37	0.33
	(180.0)	(170.4)	(155.4)		(132.7)	(124.6)	(113.3)	(102.6)	(97.2)	(88.5)	1-Hour	20.26	20.44	20.11		20.49	19.55	18.08	18.75	17.83	16.29
CO	34.8	33.3	31.0		20.3	19.1	17.4	15.74	14.92	13.57	8-Hour	14.58	14.96	15.51		12.36	11.88	11.08	12.06	11.49	10.53
	(276.3)	(264.6)	(246.3)		(161.5)	(151.6)	(137.9)	(124.9)	(118.4)	(107.7)	1-Hour	31.10	31.74	31.88		24.94	23.80	22.02	22.83	21.71	19.83

Note: DB = duct burner; IC = inlet chiller

^a Concentrations are based on highest predicted concentrations from AERMOD using 5 years of meteorological data for 1990 to 1994 consisting of surface and upper air data from the National Weather Service stations at Savannah and Charleston International Airports, respectively.

^b Pollutant concentrations were based on a modeled or generic concentration predicted using a modeled emission rate of 10 g/s. Pollutant-specific concentrations were then estimated by multiplying the modeled concentration (at 10 g/s) by the ratio of the pollutant-specific emission rate to the modeled emission rate of 10 g/s.

TABLE 6-7
MAXIMUM CONCENTRATIONS PREDICTED FOR THE LOAD ANALYSIS OF THE TWO CTS FIRING NATURAL GAS AND FUEL OIL
IN COMBINED-CYCLE OPERATION AT THE PROJECT VICINITY (PROJECT SITE LAND USE)

Pollutant	Maximum Emission Rates [g/s (lb/hr)] by Operating Load and Air Temperature										Averaging Time	Maximum Predicted Concentrations (ug/m ³) by Operating Load and Air Temperature ^a											
	Base Load - DB				75% Load			50% Load				Base Load - DB				75% Load			50% Load				
	20°F	59°F	95°F	95°F - IC	20°F	59°F	95°F	20°F	59°F	95°F		20°F	59°F	95°F	95°F - IC	20°F	59°F	95°F	20°F	59°F	95°F		
	Case 5	Case 6	Case 7	Case 8	Case 9	Case 10	Case 11	Case 12	Case 13	Case 14		Case 5	Case 6	Case 7	Case 8	Case 9	Case 10	Case 11	Case 12	Case 13	Case 14		
<u>Natural Gas</u>																							
Generic ^b	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	Annual	0.36	0.38	0.42	0.38	0.47	0.47	0.49	0.66	0.66	0.67		
											24-Hour	5.04	5.41	6.00	5.42	6.85	6.84	7.20	9.30	9.41	9.52		
											8-Hour	10.01	10.74	11.82	10.76	13.40	13.40	14.09	17.16	17.31	17.49		
											3-Hour	11.85	12.78	14.05	12.80	15.68	15.67	16.31	20.22	20.39	20.59		
											1-Hour	14.21	15.20	16.32	15.22	17.73	17.73	18.47	21.90	22.05	22.20		
PM ₁₀ /PM _{2.5}	3.4	3.4	3.4	3.4	2.4	2.4	2.4	2.4	2.4	2.4	Annual	0.122	0.131	0.141	0.131	0.113	0.112	0.118	0.1562	0.1577	0.1591		
	(27.2)	(27.1)	(26.9)	(27.1)	(19.2)	(19.1)	(19.0)	(18.9)	(18.9)	(18.8)	24-Hour	1.72	1.85	2.04	1.85	1.65	1.64	1.72	2.22	2.24	2.25		
NO _x	7.3	6.9	6.6	6.9	3.8	3.5	3.2	3.0	2.8	2.6	Annual	0.26	0.266	0.273	0.267	0.177	0.163	0.159	0.196	0.187	0.174		
	(57.6)	(55.1)	(52.0)	(55.1)	(30.2)	(27.8)	(25.7)	(23.8)	(22.3)	(20.5)	1-Hour	10.32	10.55	10.70	10.57	6.74	6.22	5.99	6.57	6.20	5.74		
CO	13.3	13.1	12.8	13.1	2.8	2.6	2.4	2.2	2.1	1.9	8-Hour	13.34	14.07	15.15	14.10	3.72	3.43	3.34	3.76	3.56	3.31		
	(105.8)	(104.0)	(101.7)	(104.0)	(22.0)	(20.3)	(18.8)	(17.4)	(16.3)	(15.0)	1-Hour	18.95	19.91	20.91	19.93	4.92	4.54	4.37	4.80	4.53	4.20		
	Base Load - DB				75% Load				50% Load				Base Load - DB				75% Load				50% Load		
	20°F	59°F	95°F		20°F	59°F	95°F		20°F	59°F	95°F		20°F	59°F	95°F		20°F	59°F	95°F		20°F	59°F	95°F
	Case 18	Case 19	Case 20		Case 21	Case 22	Case 23		Case 24	Case 25	Case 26		Case 18	Case 19	Case 20		Case 21	Case 22	Case 23		Case 24	Case 25	Case 26
<u>Fuel Oil</u>																							
Generic ^b	10.00	10.00	10.00		10.00	10.00	10.00	10.00	10.00	10.00	Annual	0.23	0.25	0.28		0.34	0.35	0.35	0.43	0.43	0.43		
											24-Hour	3.22	3.48	3.82		4.95	5.05	5.16	6.44	6.47	6.51		
											8-Hour	8.60	8.99	9.43		10.24	10.41	10.68	12.92	12.99	13.10		
											3-Hour	9.63	10.20	10.86		12.07	12.18	12.48	15.07	15.13	15.22		
											1-Hour	11.37	11.76	12.19		14.49	14.76	15.05	17.28	17.34	17.42		
PM ₁₀ /PM _{2.5}	4.62	4.60	4.58		4.46	4.45	4.44	4.42	4.41	4.40	Annual	0.107	0.115	0.126		0.15	0.15	0.16	0.19	0.19	0.19		
	(36.6)	(36.5)	(36.3)		(35.4)	(35.3)	(35.2)	(35.1)	(35.0)	(34.9)	24-Hour	1.48	1.60	1.75		2.21	2.25	2.29	2.85	2.86	2.87		
NO _x	22.7	21.5	19.6		16.7	15.7	14.3	12.9	12.3	11.1	Annual	0.52	0.54	0.54		0.57	0.55	0.51	0.56	0.53	0.48		
	(180.0)	(170.4)	(155.4)		(132.7)	(124.6)	(113.3)	(102.6)	(97.2)	(88.5)	1-Hour	25.79	25.24	23.86		24.21	23.16	21.47	22.34	21.24	19.42		
CO	34.8	33.3	31.0		20.3	19.1	17.4	15.74	14.92	13.57	8-Hour	29.93	29.96	29.27		20.83	19.90	18.56	20.33	19.37	17.78		
	(276.3)	(264.6)	(246.3)		(161.5)	(151.6)	(137.9)	(124.9)	(118.4)	(107.7)	1-Hour	39.58	39.19	37.82		29.48	28.20	26.14	27.20	25.86	23.64		

Note: DB = duct burner; IC = inlet chiller

^a Concentrations are based on highest predicted concentrations from AERMOD using 5 years of meteorological data for 1990 to 1994 consisting of surface and upper air data from the National Weather Service stations at Savannah and Charleston International Airports, respectively.

^b Pollutant concentrations were based on a modeled or generic concentration predicted using a modeled emission rate of 10 g/s. Pollutant-specific concentrations were then estimated by multiplying the modeled concentration (at 10 g/s) by the ratio of the pollutant-specific emission rate to the modeled emission rate of 10 g/s.

TABLE 6-8
SUMMARY OF MAXIMUM CONCENTRATIONS PREDICTED FOR THE LOAD ANALYSIS
OF THE PROPOSED CTS ONLY COMPARED TO EPA CLASS II SIGNIFICANT IMPACT LEVELS

Pollutant	Averaging Time	Maximum Concentration (ug/m ³) ^a			EPA Class II Significant Impact Levels (ug/m ³)
		Natural Gas ^b	Fuel Oil ^b	Maximum ^c	
<u>2 CTS- SAVANNAH LAND USE</u>					
PM ₁₀	Annual	0.11	0.13	0.11	1
	24-Hour	0.98	1.25	1.25	5
PM _{2.5}	Annual	0.11	0.13	0.11	0.3
	24-Hour	0.98	1.25	1.25	1.2
NO _x	Annual	0.20	0.40	0.22	--
	Annual	0.15	^d 0.30	^d 0.16	1
NO ₂	1-Hour	9.01	20.5	20.5	--
	1-Hour	6.76	^d 15.4	^d 15.4	9.4
CO	8-Hour	9.00	15.5	15.5	500
	1-Hour	17.6	31.9	31.9	2,000
<u>2 CTS- PROJECT SITE LAND USE</u>					
PM ₁₀	Annual	0.16	0.19	0.16	1
	24-Hour	2.25	2.87	2.87	5
PM _{2.5}	Annual	0.16	0.19	0.16	0.3
	24-Hour	2.25	2.87	2.87	1.2
NO _x	Annual	0.27	0.57	0.31	--
	Annual	0.20	^d 0.43	^d 0.23	1
NO ₂	1-Hour	10.70	25.8	25.8	--
	1-Hour	8.02	^d 19.3	^d 19.3	9.4
CO	8-Hour	15.15	30.0	30.0	500
	1-Hour	20.9	39.6	39.6	2,000

^a Concentrations are based on highest predicted concentrations from AERMOD using 5 years of meteorological data for 1990 to 1994 consisting of surface and upper air data from the National Weather Service stations at Savannah and Charleston International Airports, respectively.

^b Maximum annual concentrations are based on CTS firing gas for 8,760 hours per year.

^c Maximum annual concentrations are based on CTS firing natural gas for fuel oil 8,760 hours per year and fuel oil for 1,000 hours per year.

^d NO₂ impacts based on EPA Modeling Guidelines using NO_x to NO₂ conversion factor of 0.75 .

TABLE 6-9
SUMMARY OF MAXIMUM CONCENTRATIONS PREDICTED FOR THE PROJECT
COMPARED TO EPA CLASS II SIGNIFICANT IMPACT LEVELS

Pollutant	Operating Conditions	Averaging Time	Maximum Concentration (ug/m ³) ^a		EPA Class II Significant Impact Levels (ug/m ³)
			Savannah Land Use	Project Site Land Use	
<u>2 CTs, Fuel Heater, Auxiliary Boiler, Cooling Tower</u>					
PM ₁₀	Fuel Oil, 50% Load, 95°F ^b	Annual	0.15	0.22	1
	Fuel Oil, 50% Load, 95°F	24-Hour	1.42	3.02	5
PM _{2.5}	Fuel Oil, 50% Load, 95°F ^b	Annual	0.15	0.22	0.3
	Fuel Oil, 50% Load, 95°F	24-Hour	1.42	3.02	1.2
<u>2 CTs, Fuel Heater, Auxiliary Boiler</u>					
NO _x	Fuel Oil, Natural Gas ^c	Annual	0.40	0.43	1
NO ₂	Fuel Oil, Natural Gas ^c	Annual	0.30	^d 0.33	1
NO _x	Fuel Oil, 75% Load, 20°F	1-Hour	20.8	24.8	9.4
	Fuel Oil, 75% Load, 20°F	1-Hour	15.6	^d 18.6	9.4
NO ₂	Cold startup	1-Hour	73.6	88.2	9.4
	Cold startup	1-Hour	55.2	^d 66.1	9.4
CO	Fuel Oil, 100% Load, 95°F, Duct firing	8-Hour	15.9	--	500
	Fuel Oil, 100% Load, 20°F, Duct firing	8-Hour	--	30.2	500
	Cold startup- 5 hours; Natural Gas, 100% Load, 95°F, Duct firing- 3 hours	8-Hour	38.8	65.8	500
	Fuel Oil, 100% Load, 95°F, Duct firing	1-Hour	32.3	--	2,000
	Fuel Oil, 100% Load, 20°F, Duct firing	1-Hour	--	39.9	2,000
	Cold startup	1-Hour	265	316	2,000

^a Concentrations are based on highest predicted concentrations from AERMOD using 5 years of meteorological data for 1990 to 1994 consisting of surface and upper air data from the National Weather Service stations at Savannah and Charleston International Airports, respectively.

^b Annual concentrations based on CTs firing natural gas or fuel oil 8,760 hours per year.

^c CTs annual operation:

Operation	Hours
Natural gas- baseload, 59°F	1,601
Natural gas- baseload, with duct firing, 59°F	4,000
Fuel oil- baseload, 59°F	1,000
Warm start	749
Cold start	50
Shut down	300
Downtime for maintenance	1,060
	8,760

^d NO₂ impacts based on EPA Modeling Guidelines using NO_x to NO₂ conversion factor of 0.75 .

**TABLE 6-10
MAXIMUM POLLUTANT CONCENTRATIONS PREDICTED
FOR THE PSD CLASS I SIGNIFICANT IMPACT ANALYSIS**

Pollutant	Averaging Time	Maximum Concentrations ^{a,b} (ug/m ³)	Significant Impact Level (ug/m ³)
<u>2 CTs, Fuel Heater, Auxiliary Boiler, Cooling Tower^c</u>			
PM ₁₀	Annual	0.0050	0.2
	24-Hour	0.051	0.3
<u>2 CTs, Fuel Heater, Auxiliary Boiler^d</u>			
NO _x	Annual	0.0080	--
NO ₂	Annual	0.0060 ^e	0.1

^a Concentrations are based on highest predicted concentrations from AERMOD using 5 years of meteorological data for 1990 to 1994 consisting of surface and upper air data from the National Weather Service stations at Savannah and Charleston International Airports, respectively

^b Highest impacts predicted at 50 km in the directions of the 3 PSD Class I areas located within 200 km of the Project:

Wolf Island National Wilderness Area - 101 km

Okefenokee NWA - 162 km

Cape Romain NWA - 167 km

^c CTs firing fuel oil at 50% load, 95 °F.

^d CTs annual operation as follows:

<u>Operation</u>	<u>Hours</u>
Natural gas- baseload, 59°F	1,601
Natural gas- baseload, with duct firing, 59°F	4,000
Fuel oil- baseload, 59°F	1,000
Warm start	749
Cold start	50
Shut down	300
Downtime for maintenance	1,060
	<u>8,760</u>

^e NO₂ impacts based on EPA Modeling Guidelines using NO_x to NO₂ conversion factor of 0.75 .

TABLE 6-11
MAXIMUM PREDICTED PM_{2.5} AND NO₂ IMPACTS COMPARED TO THE NAAQS

Averaging Time and Rank	Maximum Concentration (µg/m ³) ^a			Receptor Location		Year	AAQS (µg/m ³)
	Modeled Sources ^d	Background ^b	Total	UTM- East (m)	UTM- North (m)		
PM_{2.5}							
24-Hour, Highest 5-Year Average	5.3	25.0	30.3	--	--	--	35
Based on yearly values of:							
24-Hour, Highest	5.9	--	--	473,200	3,571,900	1990	--
	4.8	--	--	473,879	3,570,992	1991	--
	5.2	--	--	473,835	3,570,972	1992	--
	5.2	--	--	473,835	3,570,972	1993	--
	5.4	--	--	473,835	3,570,972	1994	--
NO_x							
1-Hour, 8th Highest 5-Year Average	90.4	40.0	130.4	472,600	3,570,700	--	--
Based on yearly values of:							
1-Hour, 8th Highest	82.0	--	--	472,600	3,570,700	1990	--
	83.9	--	--	472,600	3,570,700	1991	--
	89.3	--	--	472,600	3,570,700	1992	--
	97.4	--	--	472,600	3,570,700	1993	--
	99.5	--	--	472,600	3,570,700	1994	--
NO₂							
Based on NO_x to NO₂ Conversion Factor of 75%							
1-Hour, 8th Highest 5-Year Average	67.8	40.0	107.8	472,600	3,570,700	--	188
Based on yearly values of:							
1-Hour, 8th Highest	61.5	--	--	472,600	3,570,700	1990	--
	62.9	--	--	472,600	3,570,700	1991	--
	66.9	--	--	472,600	3,570,700	1992	--
	73.0	--	--	472,600	3,570,700	1993	--
	74.6	--	--	472,600	3,570,700	1994	--
NO₂ ^c							
Based on PVMRM method with Ozone Background Concentration of 83 PPB							
1-Hour, 8th Highest 5-Year Average	56.8	40.0	96.8	472,800	3,571,900	--	188
Based on yearly values of:							
1-Hour, 8th Highest	57.5	--	--	472,800	3,571,900	1990	--
	56.3	--	--	472,800	3,571,900	1991	--
	54.3	--	--	472,800	3,571,900	1992	--
	59.6	--	--	472,800	3,571,900	1993	--
	56.4	--	--	472,800	3,571,900	1994	--

^a Concentrations are based on concentrations predicted using 5 years of meteorological data from 1990 to 1994 of surface and upper air data from the National Weather Service stations at Savannah and Charleston International Airports, respectively.

^c Based on background concentration provided by GDNR.

^c PVMRM is Plume Volume Molar Ratio Method assuming default values for NO₂/NO_x ambient equilibrium ratio of 0.90 and in-stack NO₂/NO_x ratio of 0.10.

^d For the proposed and existing CTs, sources were modeled assuming startup conditions for NO_x and 50% operating load for PM_{2.5}.

TABLE 6-12
AIR TOXICS ANALYSIS
EFFINGHAM PLANT EXPANSION PROJECT

Pollutant	CAS No.	Emission Rate ^a		AAC ^b (µg/m ³)	AAC ^c Averaging Time	Project Impact ^c	Exceed AAC?
		Hourly (lb/hr)	Annual (TPY)				
1,3-Butadiene	106-99-0	3.1E-02	1.9E-02	2.0	Annual	2.4E-05	No
Acetaldehyde	75-07-0	7.4E-02	3.3E-01	4.5	Annual	4.2E-04	No
Acrolein	107-02-8	1.2E-02	5.2E-02	0.02	Annual	6.6E-05	No
Ammonia	7664-41-7	4.5E+01	1.7E+02	100.0	Annual	2.2E-01	No
Arsenic		2.2E-02	1.1E-02	0.00023	Annual	1.4E-05	No
Benzene	71-43-2	1.1E-01	2.8E-01	0.13	Annual	3.6E-04	No
Beryllium		6.1E-04	6.3E-04	0.004	Annual	8.0E-07	No
Cadmium		9.4E-03	1.1E-02	0.006	Annual	1.5E-05	No
Chromium		2.2E-02	2.4E-02	0.79	24-Hour	1.1E-03	No
Cobalt		3.8E-05	1.5E-04	0.08	24-Hour	2.0E-06	No
Ethylbenzene	100-41-4	5.9E-02	5.2E-01	1,000.0	Annual	6.6E-04	No
Formaldehyde	50-00-0	4.6E-01	3.6E+00	0.77	Annual	4.6E-03	No
n-Hexane	110-54-3	5.8E-04	2.3E-03	700.0	Annual	3.0E-06	No
Lead-Total		2.7E-02	2.8E-02	0.40	24-Hour	1.4E-03	No
Manganese		1.6E+00	1.6E+00	0.05	Annual	2.0E-03	No
Mercury		2.4E-03	2.8E-03	0.30	Annual	3.6E-06	No
Nickel		9.0E-03	1.3E-02	0.0042	Annual	1.6E-05	No
Propylene oxide	75-56-9	5.4E-02	4.7E-01	30.0	Annual	6.0E-04	No
Selenium		4.9E-02	4.9E-02	0.16	24-Hour	2.6E-03	No
Toluene	108-88-3	2.4E-01	2.1E+00	5,000.0	Annual	2.7E-03	No
Xylenes	1330-20-7	1.2E-01	1.0E+00	100.0	Annual	1.3E-03	No
Naphthalene	91-20-3	6.9E-02	8.9E-02	3.0	Annual	1.1E-04	No
POMs		6.9E-02	9.1E-02	0.16	24-Hour	3.6E-03	No

^a See Tables A-13 and A-14 for emission rates.

^b See Table 6-5* for AAC and averaging times.

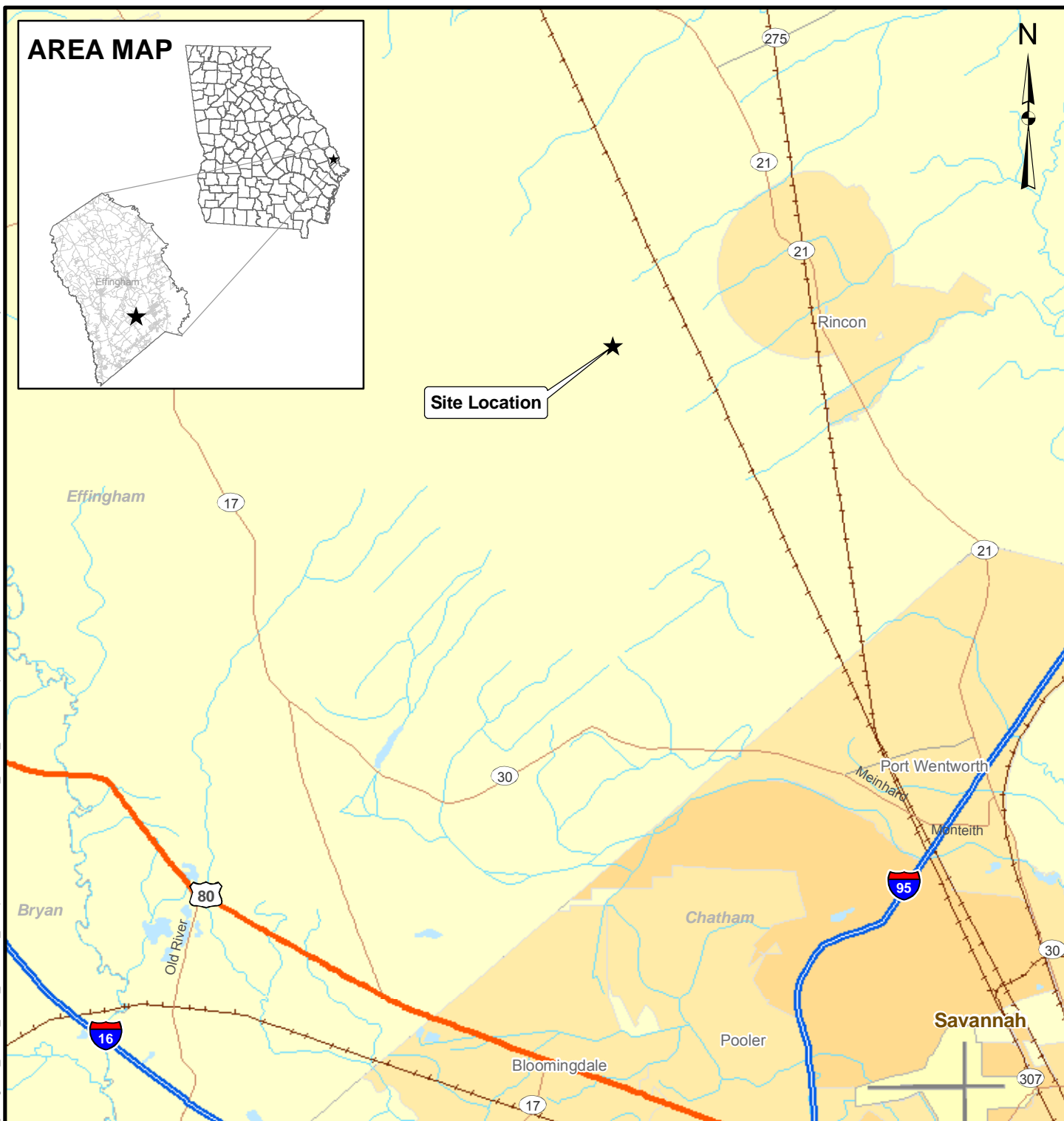
^c Based on modeling impacts using generic 10 g/s (79.37 lb/hr) emission rate for each CT.

Modeled Impact, Annual Average (µg/m³) = 0.443

Modeled Impact, 24-Hour Average (µg/m³) = 4.142

FIGURES

Map Document: G:\PROJECTS\2010\103-87522_MackinawPower\VA_Effingham_Power_Plant_PSD\Rev_0\MapDocuments\10387522_A001_LocationMap.mxd / Modified 5/7/2010 2:03:44 PM / Plotted 5/7/2010 2:08:02 PM by riamar

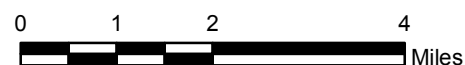


LEGEND

- ★ Effingham Power Plant Location

REFERENCES

1. Effingham Power Plant Location, Mackinaw Power, 2010.



FILE No. 10387522_A001
PROJECT No. 103-87522 REV. 0

SCALE	AS SHOWN
DATE	5/7/2010
DESIGN	SKM
GIS	NRL
CHECK	XXX
REVIEW	XXX

GENERAL LOCATION

MACKINAW POWER

FIGURE

1-1

Map Document: G:\PROJECTS\2010\103-87522_MackinawPower\VA_Effingham_Power_Plant_PSD\Rev_0\MapDocuments\10387522_A001_LocationMap.mxd / Modified 5/7/2010 2:08:10 PM / Plotted 5/7/2010 2:19:12 PM by riamar



LEGEND

- ★ Effingham Power Plant Location
- Property Boundary

REFERENCES

- Effingham Power Plant Location, Property Boundary Mackinaw Power, 2010.
- Aerial Imagery, Microsoft Virtual Earth Online, 2010.



SCALE	AS SHOWN
DATE	5/7/2010
DESIGN	SKM
GIS	NRL
CHECK	XXX
REVIEW	XXX

SITE LOCATION

FILE No.	10387522_A002
PROJECT No.	103-87522
REV.	0

MACKINAW POWER

FIGURE

1-2

BASELOAD OPERATION
AMBIENT TEMPERATURE OF 20°F

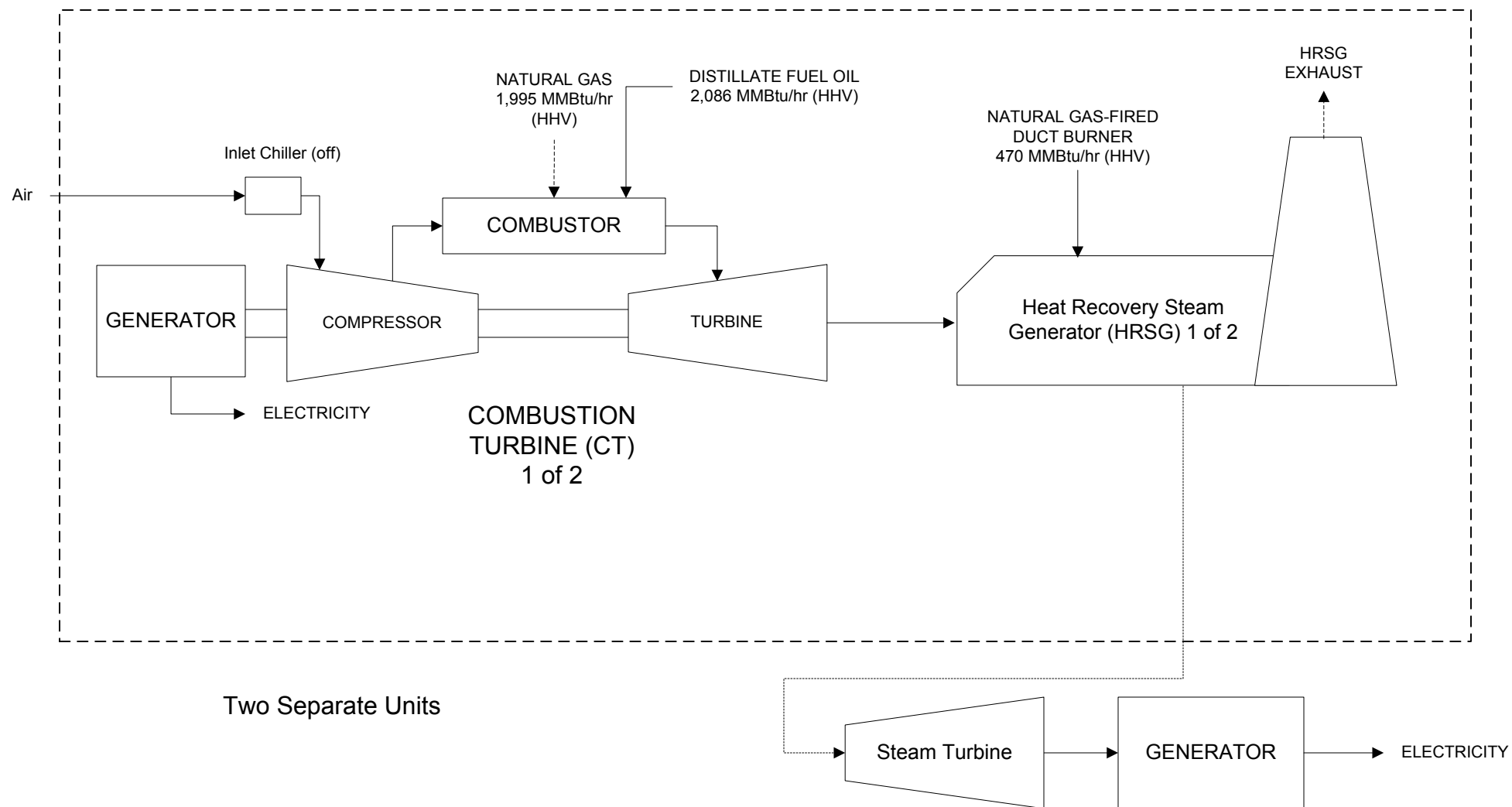


Figure 2-1. Process Flow Diagram for Each CT/HRSG Train
Baseload Operation, Turbine Inlet Temperature of 20°F
Effingham Power Plant, GA

Source: Golder, 2010.

Process Flow Legend

Solid/Liquid ———→
Gas - - - - -→
Steam ······→



BASELOAD OPERATION
AMBIENT TEMPERATURE OF 59°F

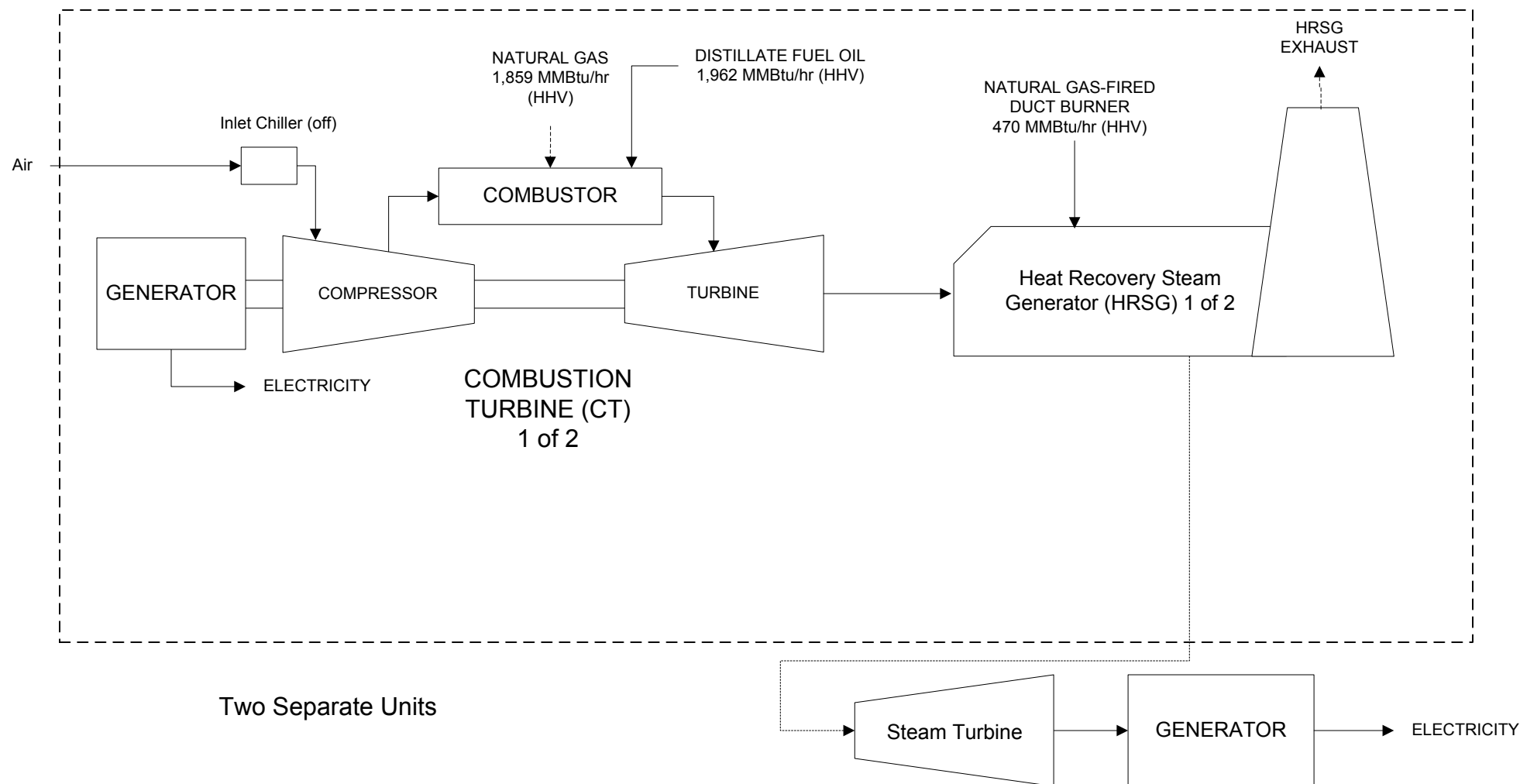


Figure 2-2. Process Flow Diagram for Each CT/HRSG Train
Baseload Operation, Turbine Inlet Temperature of 59°F
Effingham Power Plant, GA

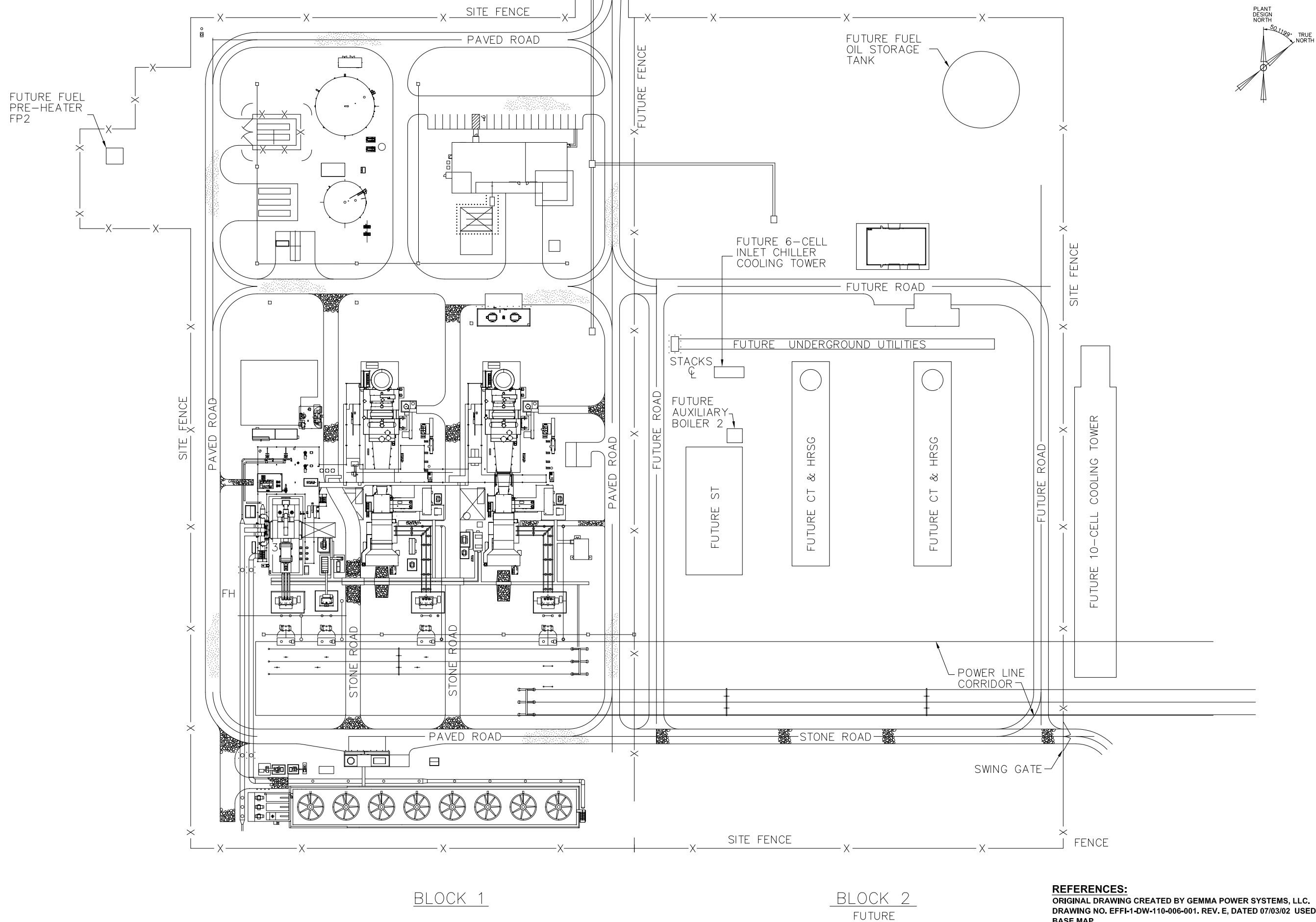
Source: Golder, 2010.

Process Flow Legend

Solid/Liquid ———→
Gas - - - - -→
Steam ······→



Drawing file: 10387522_A003_FacilityPlotPlan.dwg Jul 08, 2010 -- 4:07pm



MACKINAW POWER

PROJECT

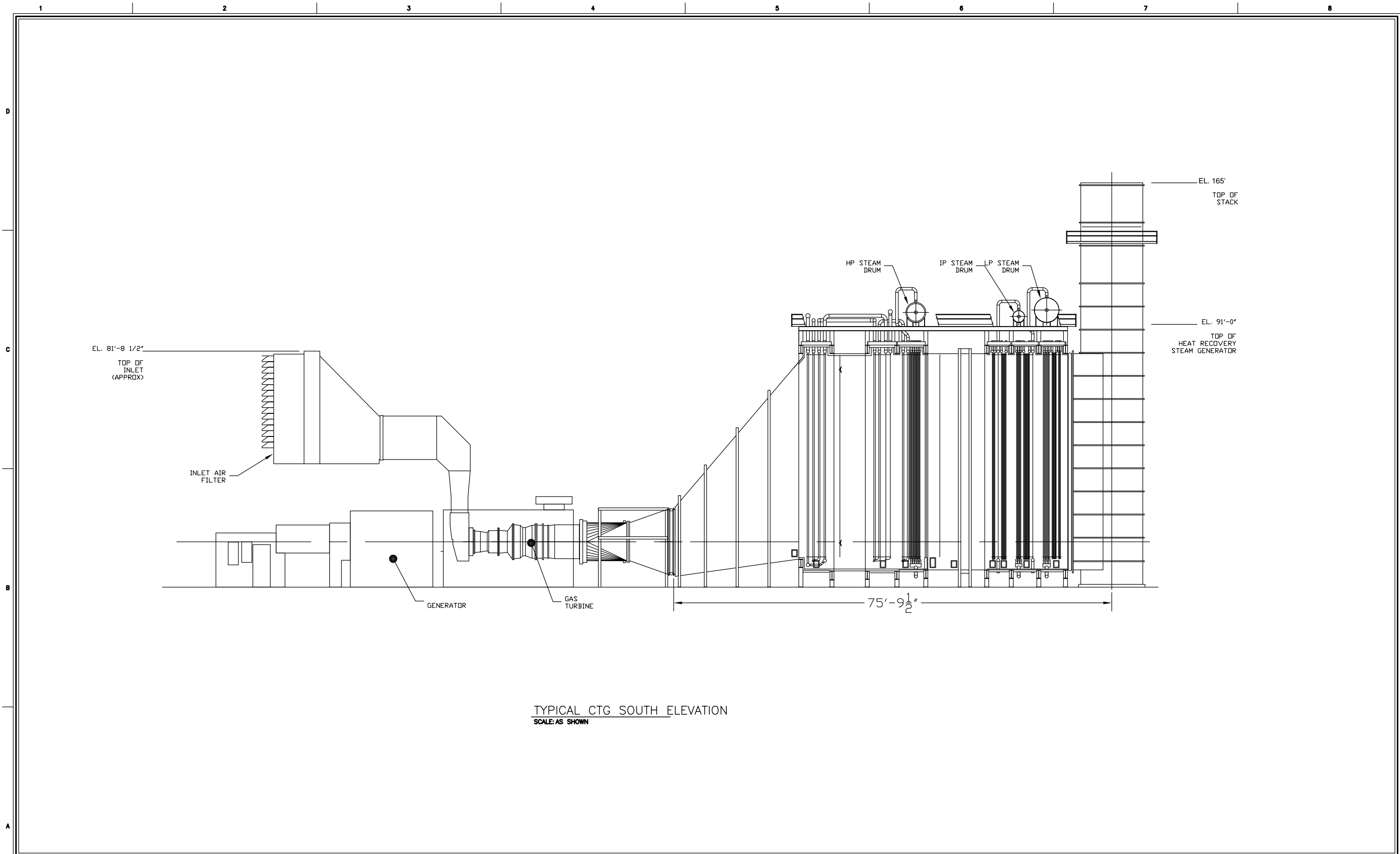
FACILITY PLOT PLAN

TITLE

PROJECT No. 103-87522		
FILE No. 10387522_A003		
REV. 0	SCALE AS SHOWN	
DESIGN	SKM	05/07/10
CADD	NRL	07/08/10
CHECK		
REVIEW		

FIGURE 2-4

REFERENCES:
ORIGINAL DRAWING CREATED BY GEMMA POWER SYSTEMS, LLC.
DRAWING NO. EFFI-1-DW-110-006-001. REV. E, DATED 07/03/02 USED AS
BASE MAP.



				DESIGNED BY	WLJ
				CHECKED BY	SKM
				APPR. BY	
				CLIENT APPR.	
B	09/05/2008	MINOR CORRECTIONS	WLJ		
A	09/04/2008	INITIAL ISSUE	WLJ		
NO	DATE	REVISION	BY	CHK	APPR.

Atlanta, Georgia

SHEET TITLE
PROFILE OF COMBUSTION TURBINE
AND
HEAT RECOVERY STEAM GENERATOR

JOB NAME
MACKINAW POWER

JOB NO. 367507	REV. NO. B
FILENAME 0733618B004 Rev2	DWG. NO. FIGURE 2-5
SCALE AS SHOWN	

APPENDIX A
DETAILED EMISSIONS CALCULATIONS

TABLE A-1
DESIGN INFORMATION AND STACK PARAMETERS FOR THE EFFINGHAM PLANT EXPANSION PROJECT
GE FRAME 7FA CT, NATURAL GAS, BASE LOAD

Parameter	CT Only				CT with DB			
	Ambient Temperature/Case No.				Ambient Temperature/Case No.			
	20 °F Case 1	59 °F Case 2	95 °F Case 3	95 °F Case 4	20 °F Case 5	59 °F Case 6	95 °F Case 7	95 °F Case 8
Case Description	CT	CT	CT	CT+IC	CT+DB	CT+DB	CT+DB	CT+IC+DB
Inlet Chiller (IC) Status	Off	Off	Off	On	Off	Off	Off	On
Relative Humidity (%)	80	60	50	50	80	60	50	50
Fuel Information								
Fuel heating value (Btu/ft ³ , HHV) - provided	1,050	1,050	1,050	1,050	1,050	1,050	1,050	1,050
Fuel density (lb/ft ³) - typical	0.044	0.044	0.044	0.044	0.044	0.044	0.044	0.044
Fuel heating value (Btu/lb, HHV) - calculated	23,864	23,864	23,864	23,864	23,864	23,864	23,864	23,864
Combustion Turbine Performance								
Gross power output (MW) - provided	193.10	173.80	154.80	173.80	193.10	173.80	154.80	173.80
Fuel usage (MMft ³ /hr) - provided	1.90	1.77	1.61	1.77	1.90	1.77	1.61	1.77
Heat Input (MMBtu/hr, HHV) - calculated	1,995	1,859	1,691	1,859	1,995	1,859	1,691	1,859
Gross heat rate (Btu/kWh, HHV) - calculated	10,331	10,693	10,921	10,693	10,331	10,693	10,921	10,693
Mass Flow (lb/hr) - provided (fuel mass added for DB)	3,929,264	3,650,916	3,333,093	3,650,916	3,948,959	3,670,611	3,352,788	3,670,611
Duct Burner (DB)								
Heat input (MMBtu/hr, HHV)	--	--	--	--	470	470	470	470
Fuel usage (ft ³ /hr) - calculated	--	--	--	--	447,619	447,619	447,619	447,619
Fuel usage (lb/hr) - calculated	--	--	--	--	19,695	19,695	19,695	19,695
CT/DB Exhaust Flow								
CT Exhaust Temperature (°F) - provided	1,074	1,113	1,154	1,113	1,074	1,113	1,154	1,113
Molecular Weight - provided	28.48	28.38	28.22	28.38	28.41	28.33	28.22	28.38
Moisture Content (%) - provided	7.55	8.37	9.88	8.37	7.55	8.37	9.88	8.37
Oxygen Content (%) - provided	12.75	12.57	12.34	12.57	12.75	12.57	12.34	12.57
Volume flow (acfm) - calculated	2,575,173	2,462,227	2,319,550	2,462,227	2,594,458	2,479,878	2,333,256	2,475,509
HRSG Stack								
Stack Height (ft) - provided	165	165	165	165	165	165	165	165
Stack Diameter (ft) - provided	19	19	19	19	19	19	19	19
Stack Temperature (°F) - provided	203.0	202.0	201.0	202.0	203.0	202.0	201.0	202.0
HRSG Volume flow (acfm) - calculated	1,112,999	1,036,233	949,952	1,036,233	1,121,333	1,043,661	955,565	1,041,823
Velocity (ft/sec) - calculated	65.4	60.9	55.8	60.9	65.9	61.3	56.2	61.2

Note: Universal gas constant = 1,545.4 ft-lb(force)/°R; atmospheric pressure = 2,116.8 lb(force)/ft²; 14.7 lb/ft².

Volume flow (acfm) = (mass flow (lb/hr)/molecular weight) x 1545.4 (gas constant, R) x actual temperature (°R)/[2116.8 lb/ft² (pressure)] / 60 min/hr.

Velocity (ft/sec) = Volume flow (acfm) / [(diameter)² / 4] x 3.14159 / 60 sec/min.

Source: Mackinaw Power, 2010, Golder Associates, 2010.

TABLE A-2
MAXIMUM EMISSIONS FOR CRITERIA POLLUTANTS FOR THE EFFINGHAM PLANT EXPANSION PROJECT
GE FRAME 7FA CT, NATURAL GAS, BASE LOAD

Parameter	CT Only				CT with DB			
	Ambient Temperature/Case No.				Ambient Temperature/Case No.			
	20 °F Case 1	59 °F Case 2	95 °F Case 3	95 °F Case 4	20 °F Case 5	59 °F Case 6	95 °F Case 7	95 °F Case 8
Nitrogen Oxides (NOx)								
Pollutant Concentration (C _p , lb/dscf) = NOx (ppmvd) x 46 lb/lb-mole (mole. wgt NOx) / 385.4 ft ³ /lb-mole								
NOx Emission Factor (E, lb/MMBtu) = C _p (lb/dscf) x F _d (dscf/MMBtu) x [20.9/(20.9 - O ₂ , dry)]								
Basis, ppmvd @15% O ₂ - provided	9	9	9	9	--	--	--	--
Basis, ppmvd - calculated	10.84	10.96	10.99	10.96	--	--	--	--
Moisture Content (%)	7.55	8.37	9.88	8.37	--	--	--	--
Oxygen Content (%)	12.75	12.57	12.34	12.57	--	--	--	--
Oxygen Content, dry (%)	13.79	13.72	13.69	13.72	--	--	--	--
Pollutant Concentration (C _p , lb/dscf)	1.3E-06	1.3E-06	1.3E-06	1.3E-06	--	--	--	--
Dry F Factor for natural gas (F _d , dscf/MMBtu)	8.710	8.710	8.710	8.710	--	--	--	--
Emission Factor, E (lb/MMBtu)	0.033	0.033	0.033	0.033	--	--	--	--
Heat Input (MMBtu/hr, HHV)	1,995	1,859	1,691	1,859	--	--	--	--
CT Uncontrolled Emission Rate, (lb/hr)	66.1	61.6	56.0	61.6	66.1	61.6	56.0	61.6
DB Emission Rate, (lb/hr)	--	--	--	--	37.6	37.6	37.6	37.6
Total CT/DB emission rate (lb/hr)	66.1	61.6	56.0	61.6	103.7	99.2	93.6	99.2
HRSG Stack ppmvd @ 15% O ₂ - provided	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
HRSG stack emission rate (lb/hr) - calculated	18.4	17.1	15.6	17.1	28.8	27.6	26.0	27.6
Carbon Monoxide (CO)								
Pollutant Concentration (C _p , lb/dscf) = CO (ppmd) x 28 lb/lb-mole (mole. wgt CO) / 385.4 ft ³ /lb-mole								
CO Emission Factor (E, lb/MMBtu) = C _p (lb/dscf) x F _d (dscf/MMBtu) x [20.9/(20.9 - O ₂ , dry)]								
Basis, ppmvd @15% O ₂ - provided	3	3	3	3	9.6	10.0	10.5	10.0
Basis, ppmvd - calculated	3.61	3.65	3.66	3.65	11.53	12.12	12.83	12.12
Moisture Content (%)	7.55	8.37	9.88	8.37	--	--	--	--
Oxygen Content (%)	12.75	12.57	12.34	12.57	--	--	--	--
Oxygen Content, dry (%)	13.79	13.72	13.69	13.72	13.79	13.72	13.69	13.72
Pollutant Concentration (C _p , lb/dscf)	2.6E-07	2.7E-07	2.7E-07	2.7E-07	8.4E-07	8.8E-07	9.3E-07	8.8E-07
Dry F Factor for natural gas (F _d , dscf/MMBtu)	8.710	8.710	8.710	8.710	8.710	8.710	8.710	8.710
Emission Factor, E (lb/MMBtu)	0.007	0.007	0.007	0.007	0.021	0.022	0.024	0.022
Heat Input (MMBtu/hr, HHV)	1,995	1,859	1,691	1,859	2,465	2,329	2,161	2,329
Uncontrolled Emission Rate, (lb/hr)	13.4	12.5	11.4	12.5	13.4	12.5	11.4	12.5
DB Emission Rate, (lb/hr)	--	--	--	--	39	39	39	39
Total CT/DB emission rate (lb/hr)	13.4	12.5	11.4	12.5	52.9	52.0	50.8	52.0
HRSG Stack ppmvd @ 15% O ₂ - provided	3.0	3.0	3.0	3.0	9.6	10.0	10.5	10.0
HRSG stack emission rate (lb/hr) - calculated	13.4	12.5	11.4	12.5	52.9	52.0	50.8	52.0
Volatile Organic Compounds (VOC)								
Pollutant Concentration (C _p , lb/dscf) = VOC (ppmd) x 16 lb/lb-mole (mole. wgt CH ₄) / 385.4 ft ³ /lb-mole								
VOC Emission Factor (E, lb/MMBtu) = C _p (lb/dscf) x F _d (dscf/MMBtu) x [20.9/(20.9 - O ₂ , dry)]								
Basis, ppmvd @15% O ₂ - provided	1.4	1.4	1.4	1.4	2.0	2.0	2.0	2.0
Basis, ppmvd - calculated	1.69	1.70	1.71	1.70	2.35	2.42	2.48	2.42
Moisture Content (%)	7.55	8.37	9.88	8.37	--	--	--	--
Oxygen Content (%)	12.75	12.57	12.34	12.57	--	--	--	--
Oxygen Content, dry (%)	13.79	13.72	13.69	13.72	13.79	13.72	13.69	13.72
Pollutant Concentration (C _p , lb/dscf)	7.0E-08	7.1E-08	7.1E-08	7.1E-08	9.8E-08	1.0E-07	1.0E-07	1.0E-07
Dry F Factor for natural gas (F _d , dscf/MMBtu)	8.710	8.710	8.710	8.710	8.710	8.710	8.710	8.710
Emission Factor, E (lb/MMBtu)	0.002	0.002	0.002	0.002	0.003	0.003	0.003	0.003
Heat Input (MMBtu/hr, HHV)	1,995	1,859	1,691	1,859	2,465	2,329	2,161	2,329
Uncontrolled Emission Rate, (lb/hr)	3.6	3.3	3.0	3.3	3.6	3.3	3.0	3.3
DB Emission Rate, (lb/hr)	--	--	--	--	3	3	3	3
Total CT/DB emission rate (lb/hr)	3.6	3.3	3.0	3.3	6.2	5.9	5.6	5.9
HRSG Stack ppmvd @ 15% O ₂ - provided	1.4	1.4	1.4	1.4	2.0	2.0	2.0	2.0
HRSG stack emission rate (lb/hr) - calculated	3.6	3.3	3.0	3.3	6.2	5.9	5.6	5.9
Particulate from CT, DB, and HRSG								
Total PM ₁₀ = PM ₁₀ (front half) + PM ₁₀ ((NH ₄) ₂ SO ₄) from Conversion of SO ₂ (back-half)								
a. PM ₁₀ (front half) (lb/hr)	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
CT - provided	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
DB (lb/hr) - calculated	0.0	0.0	0.0	0.0	3.6	3.6	3.6	3.6
Total CT/DB emission rate (lb/hr)	9.0	9.0	9.0	9.0	12.6	12.6	12.6	12.6
b. PM ₁₀ ((NH ₄) ₂ SO ₄) (back half) = 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 in CT, DB, and in SCR x (MW of SO ₃ /MW of SO ₂) x conversion of SO ₃ to (NH ₄) ₂ SO ₄ x (MW of (NH ₄) ₂ SO ₄ / MW of SO ₃)								
CT SO ₂ emission rate (lb/hr) - calculated	2.7	2.5	2.3	2.5	2.7	2.5	2.3	2.5
Conversion (%) from SO ₂ to SO ₃ in CT	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
DB SO ₂ emission rate (lb/hr) - calculated	--	--	--	--	0.6	0.6	0.6	0.6
Conversion (%) from SO ₂ to SO ₃ in DB	--	--	--	--	20.0	20.0	20.0	20.0
Remaining SO ₂ (lb/hr) after conversion - calculated	2.4	2.3	2.1	2.3	3.0	2.8	2.6	2.8
Conversion (%) from SO ₂ to SO ₃ in SCR	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
MW SO ₂ /SO ₃ (80/64)	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Conversion (%) from SO ₃ to (NH ₄) ₂ (SO ₄)	100	100	100	100	100	100	100	100
MW (NH ₄) ₂ SO ₄ /SO ₃ (132/80)	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
HRSG Particulate as (NH ₄) ₂ (SO ₄) (lb/hr) - calculated	0.71	0.66	0.60	0.66	1.01	0.96	0.90	0.96
Total HRSG stack emission rate (lb/hr) [a + b]	9.7	9.7	9.6	9.7	13.6	13.5	13.5	13.5
Sulfur Dioxide								
SO ₂ (lb/hr) = Natural gas (scf/hr) x sulfur content (gr/100 scf) x 1 lb/7000 gr x (MW SO ₂ /MW S)								
CT Fuel use (MM ft ³ /hr)	1.90	1.77	1.61	1.77	1.90	1.77	1.61	1.77
DB Fuel use (MM ft ³ /hr)	--	--	--	--	0.45	0.45	0.45	0.45
Sulfur content (grains/ 100 cf)	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
MW SO ₂ /MW S (64/32)	2	2	2	2	2	2	2	2
CT/DB emission rate (lb/hr) - calculated	2.7	2.5	2.3	2.5	3.4	3.2	2.9	3.2
HRSG stack emission rate (lb/hr) - calculated	2.7	2.5	2.3	2.5	3.4	3.2	2.9	3.2
Sulfuric Acid Mist								
Sulfuric Acid Mist (lb/hr) = SO ₂ emission (lb/hr) x Conversion to H ₂ SO ₄ (% by weight)/100 x (MW H ₂ SO ₄ /MW SO ₂)								
CT SO ₂ emission rate (lb/hr) - calculated	2.7	2.5	2.3	2.5	2.7	2.5	2.3	2.5
CT Conversion to H ₂ SO ₄ (% by weight) - provided	10	10	10	10	10	10	10	10
DB SO ₂ emission rate (lb/hr) - provided	--	--	--	--	0.6	0.6	0.6	0.6
DB Conversion to H ₂ SO ₄ (%) - provided	--	--	--	--	20	20	20	20
SCR SO ₂ (lb/hr) (remaining SO ₂ after conversion) - calc	2.4	2.3	2.1	2.3	3.0	2.8	2.6	2.8
SCR Conversion to H ₂ SO ₄ (% by weight) - provided	3	3	3	3	3	3	3	3
MW H ₂ SO ₄ /MW SO ₂ (98/64)	1.53	1.53	1.53	1.53	1.53	1.53	1.53	1.53
HRSG Stack emission rate (lb/hr)	0.53	0.49	0.45	0.49	0.55	0.52	0.47	0.52

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

Source: Mackinaw Power, 2010; Golder Associates, 2010.

TABLE A-2A
DESIGN INFORMATION AND STACK PARAMETERS FOR THE EFFINGHAM PLANT EXPANSION PROJECT
DUCT BURNER

Pollutant	Emission Factor ^a (lb/MMBtu)	Heat Input (MMBtu/hr)				Emission Rate (lb/hr)			
		Ambient Temperature/Case No.				Ambient Temperature/Case No.			
		20 °F Case 5	59 °F Case 6	95 °F Case 7	95 °F Case 8	20 °F Case 5	59 °F Case 6	95 °F Case 7	95 °F Case 8
PM ₁₀	0.0076	470	470	470	470	3.572	3.572	3.572	3.572
NO _x	0.08	470	470	470	470	37.6	37.6	37.6	37.6
CO	0.084	470	470	470	470	39.48	39.48	39.48	39.48
VOC	0.0055	470	470	470	470	2.585	2.585	2.585	2.585

^a Tables 1.4-1 and 1.4-2, AP-42, EPA, July 1998.

TABLE A-3
DESIGN INFORMATION AND STACK PARAMETERS FOR THE EFFINGHAM PLANT EXPANSION PROJECT
GE FRAME 7FA CT, NATURAL GAS, 75% LOAD

Parameter	CT Only		
	Ambient Temperature/Case No.		
	20 °F Case 9	59 °F Case 10	95 °F Case 11
Case Description	CT	CT	CT
Inlet Chiller (IC) Status	Off	Off	Off
Relative Humidity (%)	80	60	50
<u>Fuel Information</u>			
Fuel heating value (Btu/ft ³ , HHV) - provided	1,050	1,050	1,050
Fuel density (lb/ft ³) - typical	0.044	0.044	0.044
Fuel heating value (Btu/lb, HHV) - calculated	23,864	23,864	23,864
<u>Combustion Turbine Performance</u>			
Gross power output (MW) - provided	144.8	132.2	116.1
Fuel usage (MMft ³ /hr) - provided	1.56	1.44	1.33
Heat Input (MMBtu/hr, HHV) - calculated	1,638	1,512	1,397
Gross heat rate (Btu/kWh, HHV) - calculated	11,312	11,437	12,028
Mass Flow (lb/hr) - provided (fuel mass added for DB)	2,956,564	2,941,381	2,762,226
<u>CT Exhaust Flow</u>			
CT Exhaust Temperature (°F) - provided	1,200	1,159	1,190
Molecular Weight - provided	28.44	28.41	28.22
Moisture Content (%) - provided	8.13	8.26	9.80
Oxygen Content (%) - provided	12.11	12.60	12.43
Volume flow (acfm) - calculated	2,099,789	2,039,561	1,965,151
<u>HRSG Stack</u>			
Stack Height (ft) - provided	165	165	165
Stack Diameter (ft) - provided	19	19	19
Stack Temperature (°F) - provided	202.7	203.7	204.7
HRSG Volume flow (acfm) - calculated	838,271	836,107	791,658
Velocity (ft/sec) - calculated	49.3	49.1	46.5

Note: Universal gas constant = 1,545.4 ft-lb(force)/°R; atmospheric pressure = 2,116.8 lb(force)/ft²; 14.7 lb/ft².

Volume flow (acfm) = (mass flow (lb/hr)/molecular weight) x 1545.4 (gas constant, R) x actual temperature (°R)
 /[2116.8 lb/ft² (pressure)] /60 min/hr

Velocity (ft/sec) = Volume flow (acfm) / [((diameter)² /4) x 3.14159] / 60 sec/min

Source: Mackinaw Power, 2010, Golder Associates, 2010.

TABLE A-4
MAXIMUM EMISSIONS FOR CRITERIA POLLUTANTS FOR THE EFFINGHAM PLANT EXPANSION PROJECT
GE FRAME 7FA CT, NATURAL GAS, 75% LOAD

Parameter	CT Only		
	Ambient Temperature/Case No.		
	20 °F Case 9	59 °F Case 10	95 °F Case 11
Nitrogen Oxides (NOx)			
<i>Pollutant Concentration (C_d, lb/dscf) = NOx (ppmvd) x 46 lb/lb-mole (mole. wgt NOx) / 385.4 ft³/lb-mole</i>			
<i>NOx Emission Factor (E, lb/MMBtu) = C_d (lb/dscf) x F_d (dscf/MMBtu) x [20.9/(20.9 - O₂, dry)]</i>			
Basis, ppmvd @15% O ₂ - provided	9	9	9
Basis, ppmvd - calculated	11.77	10.93	10.86
Moisture Content (%)	8.13	8.26	9.80
Oxygen Content (%)	12.11	12.60	12.43
Oxygen Content, dry (%)	13.18	13.73	13.78
Pollutant Concentration (C_d , lb/dscf)	1.4E-06	1.3E-06	1.3E-06
Dry F Factor for natural gas (F_d , dscf/MMBtu)	8,710	8,710	8,710
Emission Factor, E (lb/MMBtu)	0.033	0.033	0.033
Heat Input (MMBtu/hr, HHV)	1,638	1,512	1,397
CT Uncontrolled Emission Rate, (lb/hr)	54.3	50.1	46.3
HRSG Stack ppmvd @ 15% O ₂ - provided	2.5	2.5	2.5
HRSG stack emission rate (lb/hr) - calculated	15.1	13.9	12.9
Carbon Monoxide (CO)			
<i>Pollutant Concentration (C_d, lb/dscf) = CO (ppmd) x 28 lb/lb-mole (mole. wgt CO) / 385.4 ft³/lb-mole</i>			
<i>CO Emission Factor (E, lb/MMBtu) = C_d (lb/dscf) x F_d (dscf/MMBtu) x [20.9/(20.9 - O₂, dry)]</i>			
Basis, ppmvd @15% O ₂ - provided	3	3	3
Basis, ppmvd - calculated	3.92	3.64	3.62
Moisture Content (%)	8.13	8.26	9.80
Oxygen Content (%)	12.11	12.60	12.43
Oxygen Content, dry (%)	13.18	13.73	13.78
Pollutant Concentration (C_d , lb/dscf)	2.9E-07	2.6E-07	2.6E-07
Dry F Factor for natural gas (F_d , dscf/MMBtu)	8,710	8,710	8,710
Emission Factor, E (lb/MMBtu)	0.007	0.007	0.007
Heat Input (MMBtu/hr, HHV)	1,638	1,512	1,397
Uncontrolled Emission Rate, (lb/hr)	11.0	10.2	9.4
HRSG Stack ppmvd @ 15% O ₂ - provided	3.0	3.0	3.0
HRSG stack emission rate (lb/hr) - calculated	11.0	10.2	9.4
Volatile Organic Compounds (VOC)			
<i>Pollutant Concentration (C_d, lb/dscf) = VOC (ppmd) x 16 lb/lb-mole (mole. wgt CH₄) / 385.4 ft³/lb-mole</i>			
<i>VOC Emission Factor (E, lb/MMBtu) = C_d (lb/dscf) x F_d (dscf/MMBtu) x [20.9/(20.9 - O₂, dry)]</i>			
Basis, ppmvd @15% O ₂ - provided	2	2	2
Basis, ppmvd - calculated	2.62	2.43	2.41
Moisture Content (%)	8.13	8.26	9.80
Oxygen Content (%)	12.11	12.60	12.43
Oxygen Content, dry (%)	13.18	13.73	13.78
Pollutant Concentration (C_d , lb/dscf)	1.1E-07	1.0E-07	1.0E-07
Dry F Factor for natural gas (F_d , dscf/MMBtu)	8,710	8,710	8,710
Emission Factor, E (lb/MMBtu)	0.003	0.003	0.003
Heat Input (MMBtu/hr, HHV)	1,638	1,512	1,397
Uncontrolled Emission Rate, (lb/hr)	4.2	3.9	3.6
HRSG Stack ppmvd @ 15% O ₂ - provided	2.0	2.0	2.0
HRSG stack emission rate (lb/hr) - calculated	4.2	3.9	3.6
Particulate from CT and HRSG			
<i>Total PM₁₀ = PM₁₀ (front half) + PM₁₀ ((NH₄)₂SO₄) from Conversion of SO₂ (back-half)</i>			
a. PM ₁₀ (front half) (lb/hr)			
CT - provided	9.0	9.0	9.0
b. PM ₁₀ ((NH ₄) ₂ SO ₄) (back half) = Sulfur trioxide from conversion of SO ₂ converts to ammonium sulfate (= PM ₁₀)			
<i>Particulate from conversion of SO₂ = SO₂ emissions (lb/hr) x conversion of SO₂ to SO₃ in CT and in SCR x (MW of SO₃/MW of SO₂) x conversion of SO₃ to (NH₄)₂SO₄ x (MW of (NH₄)₂SO₄/MW of SO₃).</i>			
CT SO ₂ emission rate (lb/hr)- calculated	2.2	2.1	1.9
Conversion (%) from SO ₂ to SO ₃ in CT	10.0	10.0	10.0
Remaining SO ₂ (lb/hr) after conversion - calculated	2.0	1.9	1.7
Conversion (%) from SO ₂ to SO ₃ in SCR	3.0	3.0	3.0
MW SO ₂ /SO ₃ (80/64)	1.3	1.3	1.3
Conversion (%) from SO ₂ 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
HRSG Particulate as (NH ₄) ₂ (SO ₄) (lb/hr)- calculated	0.58	0.54	0.50
Total HRSG stack emission rate (lb/hr) [a + b]	9.6	9.5	9.5
Sulfur Dioxide			
<i>SO₂ (lb/hr) = Natural gas (scf/hr) x sulfur content (gr/100 scf) x 1 lb/7000 gr x (MW SO₂ /MW S)</i>			
CT Fuel use (MM ft ³ /hr)	1.56	1.44	1.33
Sulfur content (grains/ 100 cf)	0.5	0.5	0.5
MW SO ₂ /MW S (64/32)	2	2	2
CT emission rate (lb/hr) - calculated	2.2	2.1	1.9
HRSG stack emission rate (lb/hr) - calculated	2.2	2.1	1.9
Sulfuric Acid Mist			
<i>Sulfuric Acid Mist (lb/hr) = SO₂ emission (lb/hr) x Conversion to H₂SO₄ (% by weight)/100 x (MW H₂SO₄ /MW SO₂)</i>			
CT SO ₂ emission rate (lb/hr) - calculated	2.2	2.1	1.9
CT Conversion to H ₂ SO ₄ (% by weight) - provided	10	10	10
SCR SO ₂ (lb/hr)(remaining SO ₂ after conversion) - calc	2.0	1.9	1.7
SCR Conversion to H ₂ SO ₄ (% by weight) - provided	3	3	3
MW H ₂ SO ₄ /MW SO ₂ (98/64)	1.53	1.53	1.53
HRSG Stack emission rate (lb/hr)	0.43	0.40	0.37

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

Source: Mackinaw Power, 2010; Golder Associates, 2010.

TABLE A-5
DESIGN INFORMATION AND STACK PARAMETERS FOR THE EFFINGHAM PLANT EXPANSION PROJECT
GE FRAME 7FA CT, NATURAL GAS, 50% LOAD

Parameter	CT Only		
	Ambient Temperature/Case No.		
	20 °F Case 12	59 °F Case 13	95 °F Case 14
Case Description	CT	CT	CT
Inlet Chiller (IC) Status	Off	Off	Off
Relative Humidity (%)	80	60	50
<u>Fuel Information</u>			
Fuel heating value (Btu/ft ³ , HHV) - provided	1,050	1,050	1,050
Fuel density (lb/ft ³) - typical	0.044	0.044	0.044
Fuel heating value (Btu/lb, HHV) - calculated	23,864	23,864	23,864
<u>Combustion Turbine Performance</u>			
Gross power output (MW) - provided	96.6	88.2	77.4
Fuel usage (MMft ³ /hr)- provided	1.231	1.155	1.062
Heat Input (MMBtu/hr, HHV) - calculated	1,293	1,213	1,115
Gross heat rate (Btu/kWh, HHV) - calculated	13,380	13,750	14,407
Mass Flow (lb/hr)- provided (fuel mass added for DB)	2,498,048	2,433,269	2,325,978
<u>CT Exhaust Flow</u>			
CT Exhaust Temperature (°F) - provided	1,200	1,200	1,200
Molecular Weight - provided	28.48	28.42	28.25
Moisture Content (%) - provided	7.54	7.96	9.37
Oxygen Content (%) - provided	12.77	12.94	12.92
Volume flow (acfm) - calculated	1,771,653	1,729,354	1,663,049
<u>HRSG Stack</u>			
Stack Height (ft) - provided	165	165	165
Stack Diameter (ft) - provided	19	19	19
Stack Temperature (°F) - provided	175.3	177.5	182.2
HRSG Volume flow (acfm) - calculated	678,031	664,135	643,380
Velocity (ft/sec)- calculated	39.9	39.0	37.8

Volume flow (acfm) = (mass flow (lb/hr)/molecular weight) x 1545.4 (gas constant, R) x actual temperature (°R)/[2116.8 lb/ft² (pressure)] /60 min/hr

Velocity (ft/sec) = Volume flow (acfm) / [((diameter)² /4) x 3.14159] / 60 sec/min

Note: Universal gas constant = 1,545.4 ft-lb(force)/°R; atmospheric pressure = 2,116.8 lb(force)/ft²; 14.7 lb/ft².

Source: Mackinaw Power, 2010, Golder Associates, 2010.

TABLE A-6
MAXIMUM EMISSIONS FOR CRITERIA POLLUTANTS FOR THE EFFINGHAM PLANT EXPANSION PROJECT
GE FRAME 7FA CT, NATURAL GAS, 50% LOAD

Parameter	CT Only		
	Ambient Temperature/Case No.		
	20 °F Case 12	59 °F Case 13	95 °F Case 14
Nitrogen Oxides (NOx)			
Pollutant Concentration (C_d , lb/dscf) = NOx (ppmvd) x 46 lb/lb-mole (mole. wgt NOx) / 385.4 ft ³ /lb-mole			
NOx Emission Factor (E , lb/MMBtu) = C_d (lb/dscf) x F_d (dscf/MMBtu) x [20.9/(20.9 - O ₂ , dry)]			
Basis, ppmvd @15% O ₂ - provided	9	9	9
Basis, ppmvd - calculated	10.81	10.44	10.14
Moisture Content (%)	7.54	7.96	9.37
Oxygen Content (%)	12.77	12.94	12.92
Oxygen Content, dry (%)	13.81	14.06	14.26
Pollutant Concentration (C_d , lb/dscf)	1.3E-06	1.2E-06	1.2E-06
Dry F Factor for natural gas (F_d , dscf/MMBtu)	8,710	8,710	8,710
Emission Factor, E (lb/MMBtu)	0.033	0.033	0.033
Heat Input (MMBtu/hr, HHV)	1,293	1,213	1,115
CT Uncontrolled Emission Rate, (lb/hr)	42.8	40.2	37.0
HRSG Stack ppmvd @ 15% O ₂ - provided	2.5	2.5	2.5
HRSG stack emission rate (lb/hr) - calculated	11.9	11.2	10.3
Carbon Monoxide (CO)			
Pollutant Concentration (C_d , lb/dscf) = CO (ppmd) x 28 lb/lb-mole (mole. wgt CO) / 385.4 ft ³ /lb-mole			
CO Emission Factor (E , lb/MMBtu) = C_d (lb/dscf) x F_d (dscf/MMBtu) x [20.9/(20.9 - O ₂ , dry)]			
Basis, ppmvd @15% O ₂ - provided	3	3	3
Basis, ppmvd - calculated	3.60	3.48	3.38
Moisture Content (%)	7.54	7.96	9.37
Oxygen Content (%)	12.77	12.94	12.92
Oxygen Content, dry (%)	13.81	14.06	14.26
Pollutant Concentration (C_d , lb/dscf)	2.6E-07	2.5E-07	2.5E-07
Dry F Factor for natural gas (F_d , dscf/MMBtu)	8,710	8,710	8,710
Emission Factor, E (lb/MMBtu)	0.007	0.007	0.007
Heat Input (MMBtu/hr, HHV)	1,293	1,213	1,115
Uncontrolled Emission Rate, (lb/hr)	8.7	8.2	7.5
HRSG Stack ppmvd @ 15% O ₂ - provided	3.0	3.0	3.0
HRSG stack emission rate (lb/hr) - calculated	8.7	8.2	7.5
Volatile Organic Compounds (VOC)			
Pollutant Concentration (C_d , lb/dscf) = VOC (ppmd) x 16 lb/lb-mole (mole. wgt CH ₄) / 385.4 ft ³ /lb-mole			
VOC Emission Factor (E , lb/MMBtu) = C_d (lb/dscf) x F_d (dscf/MMBtu) x [20.9/(20.9 - O ₂ , dry)]			
Basis, ppmvd @15% O ₂ - provided	1.4	1.4	1.4
Basis, ppmvd - calculated	1.68	1.62	1.58
Moisture Content (%)	7.54	7.96	9.37
Oxygen Content (%)	12.77	12.94	12.92
Oxygen Content, dry (%)	13.81	14.06	14.26
Pollutant Concentration (C_d , lb/dscf)	7.0E-08	6.7E-08	6.5E-08
Dry F Factor for natural gas (F_d , dscf/MMBtu)	8,710	8,710	8,710
Emission Factor, E (lb/MMBtu)	0.002	0.002	0.002
Heat Input (MMBtu/hr, HHV)	1,293	1,213	1,115
Uncontrolled Emission Rate, (lb/hr)	2.3	2.2	2.0
HRSG Stack ppmvd @ 15% O ₂ - provided	2.0	2.0	2.0
HRSG stack emission rate (lb/hr) - calculated	3.3	3.1	2.9
Particulate from CT and HRSG			
Total PM ₁₀ = PM ₁₀ (front half) + PM ₁₀ ((NH ₄) ₂ SO ₄) from Conversion of SO ₂ (back-half)			
a. PM ₁₀ (front half) (lb/hr)			
CT - provided	9.0	9.0	9.0
b. PM ₁₀ ((NH ₄) ₂ SO ₄) (back half) = 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 in CT and in SCR x (MW of SO ₃ /MW of SO ₂) x conversion of SO ₃ to (NH ₄) ₂ SO ₄ x (MW of (NH ₄) ₂ SO ₄ /MW of SO ₃).			
CT SO ₂ emission rate (lb/hr)- calculated	1.8	1.7	1.5
Conversion (%) from SO ₂ to SO ₃ in CT	10.0	10.0	10.0
Remaining SO ₂ (lb/hr) after conversion - calculated	1.6	1.5	1.4
Conversion (%) from SO ₂ to SO ₃ in SCR	3.0	3.0	3.0
MW SO ₂ /SO ₃ (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
HRSG Particulate as (NH ₄) ₂ (SO ₄) (lb/hr)- calculated	0.46	0.43	0.40
Total HRSG stack emission rate (lb/hr) [a + b]	9.5	9.4	9.4
Sulfur Dioxide			
SO ₂ (lb/hr) = Natural gas (scf/hr) x sulfur content (gr/100 scf) x 1 lb/7000 gr x (MW SO ₂ /MW S)			
CT Fuel use (MM ft ³ /hr)	1.23	1.16	1.06
Sulfur content (grains/ 100 cf)	0.5	0.5	0.5
MW SO ₂ /MW S (64/32)	2	2	2
CT emission rate (lb/hr) - calculated	1.8	1.7	1.5
HRSG stack emission rate (lb/hr) - calculated	1.8	1.7	1.5
Sulfuric Acid Mist			
Sulfuric Acid Mist (lb/hr) = SO ₂ emission (lb/hr) x Conversion to H ₂ SO ₄ (% by weight)/100 x (MW H ₂ SO ₄ /MW SO ₂)			
CT SO ₂ emission rate (lb/hr) - calculated	1.8	1.7	1.5
CT Conversion to H ₂ SO ₄ (% by weight) - provided	10	10	10
SCR SO ₂ (lb/hr)/(remaining SO ₂ after conversion) - calc	1.6	1.5	1.4
SCR Conversion to H ₂ SO ₄ (% by weight) - provided	3	3	3
MW H ₂ SO ₄ /MW SO ₂ (98/64)	1.53	1.53	1.53
HRSG Stack emission rate (lb/hr)	0.34	0.32	0.30

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

Source: Mackinaw Power, 2010; Golder Associates, 2010.

TABLE A-7
DESIGN INFORMATION AND STACK PARAMETERS FOR THE EFFINGHAM PLANT EXPANSION PROJECT
GE FRAME 7FA CT, DISTILLATE FUEL OIL, BASE LOAD

Parameter	CT Only			CT with DB		
	Ambient Temperature/Case No.			Ambient Temperature/Case No.		
	20 °F Case 15	59 °F Case 16	95 °F Case 17	20 °F Case 18	59 °F Case 19	95 °F Case 20
Case Description	CT	CT	CT	CT+DB	CT+DB	CT+DB
Inlet Chiller (IC) Status	Off	Off	Off	Off	Off	Off
Relative Humidity (%)	60	60	60	60	60	60
<u>Fuel Information</u>						
Fuel heating value (Btu/gal, HHV) - calculated	127,809	127,809	127,809	127,809	127,809	127,809
Fuel density (lb/gal) - typical	6.694	6.694	6.694	6.694	6.694	6.694
Fuel heating value (Btu/lb, HHV) - typical	19,093	19,093	19,093	19,093	19,093	19,093
<u>Combustion Turbine Performance</u>						
Gross power output (MW) - provided	193.5	181.5	158.9	193.5	181.5	158.9
Fuel usage (lb/hr)- provided	109,234	102,764	92,647	109,234	102,764	92,647
Heat Input (MMBtu/hr, HHV) - calculated	2,086	1,962	1,769	2,086	1,962	1,769
Gross heat rate (Btu/kWh, HHV) - calculated	10,778	10,810	11,132	10,778	10,810	11,132
Mass Flow (lb/hr)- provided	4,055,000	3,766,000	3,407,000	4,074,695	3,785,695	3,426,695
<u>Duct Burner (DB) - Natural Gas Fired</u>						
Heat input (MMBtu/hr, HHV)	--	--	--	470	470	470
Fuel usage (ft ³ /hr)- calculated	--	--	--	447,619	447,619	447,619
Fuel usage (lb/hr)- calculated	--	--	--	19,695	19,695	19,695
<u>CT Exhaust Flow</u>						
CT Exhaust Temperature (°F) - provided	1,053	1,093	1,143	1,053	1,093	1,143
Molecular Weight - provided	28.36	28.30	28.12	28.36	28.30	28.12
Moisture Content (%) - provided	10.87	11.46	13.07	10.87	11.46	13.07
Oxygen Content (%) - provided	11.24	11.11	10.77	11.24	11.11	10.77
Volume flow (acfm) - calculated	2,632,288	2,514,636	2,363,198	2,645,073	2,527,787	2,376,860
<u>HRSG Stack</u>						
Stack Height (ft) - provided	165	165	165	165	165	165
Stack Diameter (ft) - provided	19	19	19	19	19	19
Stack Temperature (°F) - provided	297.0	294.8	293.5	297.0	294.8	293.5
HRSG Volume flow (acfm) - calculated	1,317,014	1,222,181	1,110,836	1,323,411	1,228,573	1,117,257
Velocity (ft/sec)- calculated	77.4	71.8	65.3	77.8	72.2	65.7

Note: Universal gas constant = 1,545.4 ft-lb(force)/°R; atmospheric pressure = 2,116.8 lb(force)/ft²; 14.7 lb/ft².

Volume flow (acfm) = (mass flow (lb/hr)/molecular weight) x 1545.4 (gas constant, R) x actual temperature (°R)
 / [2116.8 lb/ft² (pressure)] / 60 min/hr

Velocity (ft/sec) = Volume flow (acfm) / [((diameter)² / 4) x 3.14159] / 60 sec/min

Source: Mackinaw Power, 2010, Golder Associates, 2010.

TABLE A-8
MAXIMUM EMISSIONS FOR CRITERIA POLLUTANTS FOR THE EFFINGHAM PLANT EXPANSION PROJECT
GE FRAME 7FA CT, DISTILLATE FUEL OIL, BASE LOAD

Parameter	CT Only			CT Only		
	Ambient Temperature/Case No.			Ambient Temperature/Case No.		
	20 °F Case 15	59 °F Case 16	95 °F Case 17	20 °F Case 18	59 °F Case 19	95 °F Case 20
Nitrogen Oxides (NO_x)						
Pollutant Concentration (C_d , lb/dscf) = NO_x (ppmvd) \times 46 lb/lb-mole (mole. wgt NO _x) / 385.4 ft ³ /lb-mole						
NO _x Emission Factor (E , lb/MMBtu) = C_d (lb/dscf) \times F_d (dscf/MMBtu) \times [20.9/(20.9 - O ₂ , dry)]						
Basis, ppmvd @15% O ₂ - provided	42	42	42	--	--	--
Basis, ppmvd - calculated	59.01	59.45	60.58	--	--	--
Moisture Content (%)	10.87	11.46	13.07	--	--	--
Oxygen Content (%)	11.24	11.11	10.77	--	--	--
Oxygen Content, dry (%)	12.61	12.55	12.39	--	--	--
Pollutant Concentration (C_d , lb/dscf)	7.0E-06	7.1E-06	7.2E-06	--	--	--
Dry F Factor for distillate oil (F_d , dscf/MMBtu)	9,190	9,190	9,190	--	--	--
Emission Factor, E (lb/MMBtu)	0.163	0.163	0.163	--	--	--
Heat Input (MMBtu/hr, HHV)	2,086	1,962	1,769	--	--	--
CT Uncontrolled Emission Rate, (lb/hr)	340.4	320.2	288.7	340.4	320.2	288.7
DB Emission Rate, (lb/hr)	--	--	--	37.6	37.6	37.6
Total CT/DB emission rate (lb/hr)	340.4	320.2	288.7	378.0	357.8	326.3
HRSO Stack ppmvd @ 15% O ₂ - provided	10.0	10.0	10.0	10.0	10.0	10.0
HRSO stack emission rate (lb/hr) - calculated	81.0	76.2	68.7	90.0	85.2	77.7
Carbon Monoxide (CO)						
Pollutant Concentration (C_d , lb/dscf) = CO (ppmvd) \times 28 lb/lb-mole (mole. wgt CO) / 385.4 ft ³ /lb-mole						
CO Emission Factor (E , lb/MMBtu) = C_d (lb/dscf) \times F_d (dscf/MMBtu) \times [20.9/(20.9 - O ₂ , dry)]						
Basis, ppmvd @15% O ₂ - provided	20	20	20	22.9	23.0	23.3
Basis, ppmvd - calculated	28.10	28.31	28.85	32.11	32.56	33.55
Moisture Content (%)	10.87	11.46	13.07	--	--	--
Oxygen Content (%)	11.24	11.11	10.77	--	--	--
Oxygen Content, dry (%)	12.61	12.55	12.39	12.61	12.55	12.39
Pollutant Concentration (C_d , lb/dscf)	2.0E-06	2.1E-06	2.1E-06	2.3E-06	2.4E-06	2.4E-06
Dry F Factor for distillate oil (F_d , dscf/MMBtu)	9,190	9,190	9,190	9,190	9,190	9,190
Emission Factor, E (lb/MMBtu)	0.047	0.047	0.047	0.054	0.054	0.055
Heat Input (MMBtu/hr, HHV)	2,086	1,962	1,769	2,556	2,432	2,239
Uncontrolled Emission Rate, (lb/hr)	98.7	92.8	83.7	98.7	92.8	83.7
DB Emission Rate, (lb/hr)	--	--	--	39	39	39
Total CT/DB emission rate (lb/hr)	98.7	92.8	83.7	138.1	132.3	123.2
HRSO Stack ppmvd @ 15% O ₂ - provided	20.0	20.0	20.0	22.9	23.0	23.3
HRSO stack emission rate (lb/hr) - calculated	98.7	92.8	83.7	138.1	132.3	123.2
Volatile Organic Compounds (VOC)						
Pollutant Concentration (C_d , lb/dscf) = VOC (ppmvd) \times 16 lb/lb-mole (mole. wgt CH ₄) / 385.4 ft ³ /lb-mole						
VOC Emission Factor (E , lb/MMBtu) = C_d (lb/dscf) \times F_d (dscf/MMBtu) \times [20.9/(20.9 - O ₂ , dry)]						
Basis, ppmvd @15% O ₂ - provided	3.5	3.5	3.5	4.4	4.5	4.6
Basis, ppmvd - calculated	4.92	4.95	5.05	6.21	6.33	6.61
Moisture Content (%)	10.87	11.46	13.07	--	--	--
Oxygen Content (%)	11.24	11.11	10.77	--	--	--
Oxygen Content, dry (%)	12.61	12.55	12.39	12.61	12.55	12.39
Pollutant Concentration (C_d , lb/dscf)	2.0E-07	2.1E-07	2.1E-07	2.6E-07	2.6E-07	2.7E-07
Dry F Factor for distillate oil (F_d , dscf/MMBtu)	9,190	9,190	9,190	9,190	9,190	9,190
Emission Factor, E (lb/MMBtu)	0.005	0.005	0.005	0.006	0.006	0.006
Heat Input (MMBtu/hr, HHV)	2,086	1,962	1,769	2,086	1,962	1,769
Uncontrolled Emission Rate, (lb/hr)	9.9	9.3	8.4	9.9	9.3	8.4
DB Emission Rate, (lb/hr)	--	--	--	2.6	2.6	2.6
Total CT/DB emission rate (lb/hr)	9.9	9.3	8.4	12.5	11.9	11.0
HRSO Stack ppmvd @ 15% O ₂ - provided	3.5	3.5	3.5	4.4	4.5	4.6
HRSO stack emission rate (lb/hr) - calculated	9.9	9.3	8.4	12.5	11.9	11.0
Particulate from CT and HRSO						
Total PM ₁₀ = PM ₁₀ (front half) + PM ₁₀ ((NH ₄) ₂ SO ₄) from Conversion of SO ₂ (back-half)						
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	3.6	3.6	3.6
Total CT/DB emission rate (lb/hr)	17.0	17.0	17.0	20.6	20.6	3.6
b. PM ₁₀ ((NH ₄) ₂ SO ₄) (back half) = Sulfur trioxide from conversion of SO ₂ converts to ammonium sulfate (= PM ₁₀)						
Particulate from conversion of SO ₂ = SO ₂ emissions (lb/hr) \times conversion of SO ₂ to SO ₃ in CT, DB, and in SCR \times (MW of SO ₃ /MW of SO ₂) \times conversion of SO ₃ to (NH ₄) ₂ SO ₄ \times (MW of (NH ₄) ₂ SO ₄ /MW of SO ₃)						
CT SO ₂ emission rate (lb/hr) - calculated	3.3	3.1	2.8	3.9	3.7	3.4
Conversion (%) from SO ₂ to SO ₃ in CT	10.0	10.0	10.0	10.0	10.0	10.0
DB SO ₂ emission rate (lb/hr) - calculated	--	--	--	0.64	0.64	0.64
Conversion (%) from SO ₂ to SO ₃ in DB	--	--	--	20.0	20.0	20.0
Remaining SO ₂ (lb/hr) after conversion - calculated	2.9	2.8	2.5	4.0	3.9	3.1
Conversion (%) from SO ₂ to SO ₃ in SCR	3.0	3.0	3.0	3.0	3.0	3.0
MW SO ₂ /MW SO ₃ (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
HRSO Particulate as (NH ₄) ₂ SO ₄ (lb/hr) - calculated	0.86	0.81	0.73	1.32	1.27	1.16
Total HRSO stack emission rate (lb/hr) [a + b]	17.9	17.8	17.7	18.3	18.3	18.2
Sulfur Dioxide						
SO ₂ (lb/hr) = Distillate oil (lb/hr) \times sulfur content(%) \times (MW SO ₂ /MW S) + Natural gas (scf/hr) \times sulfur content(gr/100 scf) \times 1 lb/7000 gr \times (MW SO ₂ /MW S)						
CT Fuel use (lb/hr)	109,234	102,764	92,647	109,234	102,764	92,647
DB Fuel use (MM ft ³ /hr)	--	--	--	0.45	0.45	0.45
Fuel Oil Sulfur content (%)	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015
NG Sulfur content (grains/ 100 cf)	0.5	0.5	0.5	0.5	0.5	0.5
MW SO ₂ /MW S (64/32)	2	2	2	2	2	2
CT emission rate (lb/hr) - calculated	3.3	3.1	2.8	3.9	3.7	3.4
HRSO stack emission rate (lb/hr) - calculated	3.3	3.1	2.8	3.9	3.7	3.4
Sulfuric Acid Mist						
Sulfuric Acid Mist (lb/hr) = SO ₂ emission (lb/hr) \times Conversion to H ₂ SO ₄ (% by weight)/100 \times (MW H ₂ SO ₄ /MW SO ₂)						
CT SO ₂ emission rate (lb/hr) - calculated	3.3	3.1	2.8	3.3	3.1	2.8
CT Conversion to H ₂ SO ₄ (% by weight) - provided	10	10	10	10	10	10
DB SO ₂ emission rate (lb/hr) - provided	--	--	--	0.6	0.6	0.6
DB Conversion to H ₂ SO ₄ (%) - provided	--	--	--	20	20	20
SCR SO ₂ (lb/hr)(remaining SO ₂ after conversion) - calc	2.9	2.8	2.5	3.5	2.8	2.5
SCR Conversion to H ₂ SO ₄ (% by weight) - provided	3	3	3	3	3	3
MW H ₂ SO ₄ /MW SO ₂ (98/64)	1.53	1.53	1.53	1.53	1.53	1.53
HRSO Stack emission rate (lb/hr)	0.64	0.60	0.54	0.66	0.60	0.54
Lead						
Lead (lb/hr) = Basis (lb/10 ¹² Btu) \times Heat Input (MMBtu/hr) / (10 ⁶ MMBtu/10 ¹² Btu)						
Emission Rate Basis (lb/10 ¹² Btu)	14	14	14	14	14	14
Heat Input (MMBtu/hr) (HHV)	2,086	1,962	1,769	2,086	1,962	1,769
HRSO Stack emission rate (lb/hr)	0.029	0.027	0.025	0.029	0.027	0.025

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

Source: Mackinaw Power, 2010; Golder Associates, 2010.

TABLE A-9
DESIGN INFORMATION AND STACK PARAMETERS FOR THE EFFINGHAM PLANT EXPANSION PROJECT
GE FRAME 7FA CT, DISTILLATE FUEL OIL, 75% LOAD

Parameter	CT Only		
	Ambient Temperature/Case No.		
	20 °F Case 21	59 °F Case 22	95 °F Case 23
Case Description	CT	CT	CT
Inlet Chiller (IC) Status	Off	Off	Off
Relative Humidity (%)	60	60	60
<u>Fuel Information</u>			
Fuel heating value (Btu/gal, HHV) - calculated	127,809	127,809	127,809
Fuel density (lb/gal) - typical	6.694	6.694	6.694
Fuel heating value (Btu/lb, HHV) - typical	19,093	19,093	19,093
<u>Combustion Turbine Performance</u>			
Gross power output (MW) - provided	145.1	135.5	119.2
Fuel usage (lb/hr)- provided	89,406	83,952	76,330
Heat Input (MMBtu/hr, HHV) - calculated	1,707	1,603	1,457
Gross heat rate (Btu/kWh, HHV) - calculated	11,764	11,829	12,226
Mass Flow (lb/hr)- provided	2,991,000	2,898,000	2,783,000
<u>CT Exhaust Flow</u>			
CT Exhaust Temperature (°F) - provided	1,196	1,200	1,200
Molecular Weight - provided	28.32	28.29	28.16
Moisture Content (%) - provided	11.72	11.85	12.65
Oxygen Content (%) - provided	10.34	10.57	10.86
Volume flow (acfm) - calculated	2,128,106	2,069,109	1,996,174
<u>HRSG Stack</u>			
Stack Height (ft) - provided	165	165	165
Stack Diameter (ft) - provided	19	19	19
Stack Temperature (°F) - provided	271.0	274.0	278.0
HRSG Volume flow (acfm) - calculated	939,400	914,895	887,456
Velocity (ft/sec)- calculated	55.2	53.8	52.2

Note: Universal gas constant = 1,545.4 ft-lb(force)/°R; atmospheric pressure = 2,116.8 lb(force)/ft²; 14.7 lb/ft².

Volume flow (acfm) = (mass flow (lb/hr)/molecular weight) x 1545.4 (gas constant, R) x actual temperature (°R)
 /[2116.8 lb/ft² (pressure)] /60 min/hr

Velocity (ft/sec) = Volume flow (acfm) / [((diameter)² /4) x 3.14159] / 60 sec/min

Source: Mackinaw Power, 2010, Golder Associates, 2010.

TABLE A-10
MAXIMUM EMISSIONS FOR CRITERIA POLLUTANTS FOR THE EFFINGHAM PLANT EXPANSION PROJECT
GE FRAME 7FA CT, DISTILLATE FUEL OIL, 75% LOAD

Parameter	CT Only		
	Ambient Temperature/Case No.		
	20 °F Case 21	59 °F Case 22	95 °F Case 23
Nitrogen Oxides (NOx)			
<i>Pollutant Concentration (C_d, lb/dscf) = NOx (ppmvd) x 46 lb/lb-mole (mole. wgt NOx) / 385.4 ft³/lb-mole</i>			
<i>NOx Emission Factor (E, lb/MMBtu) = C_d (lb/dscf) x F_d (dscf/MMBtu) x [20.9/(20.9 - O₂, dry)]</i>			
Basis, ppmvd @ 15% O ₂ - provided	42	42	42
Basis, ppmvd - calculated	65.40	63.42	60.28
Moisture Content (%)	11.72	11.85	12.65
Oxygen Content (%)	10.34	10.57	10.86
Oxygen Content, dry (%)	11.71	11.99	12.43
Pollutant Concentration (C_d , lb/dscf)	7.8E-06	7.6E-06	7.2E-06
Dry F Factor for distillate oil (F_d , dscf/MMBtu)	9.190	9.190	9.190
Emission Factor, E (lb/MMBtu)	0.163	0.163	0.163
Heat Input (MMBtu/hr, HHV)	1,707	1,603	1,457
CT Uncontrolled Emission Rate, (lb/hr)	278.6	261.6	237.8
HRSG Stack ppmvd @ 15% O ₂ - provided	10.0	10.0	10.0
HRSG stack emission rate (lb/hr) - calculated	66.3	62.3	56.6
Carbon Monoxide (CO)			
<i>Pollutant Concentration (C_d, lb/dscf) = CO (ppmd) x 28 lb/lb-mole (mole. wgt CO) / 385.4 ft³/lb-mole</i>			
<i>CO Emission Factor (E, lb/MMBtu) = C_d (lb/dscf) x F_d (dscf/MMBtu) x [20.9/(20.9 - O₂, dry)]</i>			
Basis, ppmvd @ 15% O ₂ - provided	20	20	20
Basis, ppmvd - calculated	31.14	30.20	28.70
Moisture Content (%)	11.72	11.85	12.65
Oxygen Content (%)	10.34	10.57	10.86
Oxygen Content, dry (%)	11.71	11.99	12.43
Pollutant Concentration (C_d , lb/dscf)	2.3E-06	2.2E-06	2.1E-06
Dry F Factor for distillate oil (F_d , dscf/MMBtu)	9.190	9.190	9.190
Emission Factor, E (lb/MMBtu)	0.047	0.047	0.047
Heat Input (MMBtu/hr, HHV)	1,707	1,603	1,457
Uncontrolled Emission Rate, (lb/hr)	80.7	75.8	68.9
HRSG Stack ppmvd @ 15% O ₂ - provided	20.0	20.0	20.0
HRSG stack emission rate (lb/hr) - calculated	80.7	75.8	68.9
Volatile Organic Compounds (VOC)			
<i>Pollutant Concentration (C_d, lb/dscf) = VOC (ppmd) x 16 lb/lb-mole (mole. wgt CH₄) / 385.4 ft³/lb-mole</i>			
<i>VOC Emission Factor (E, lb/MMBtu) = C_d (lb/dscf) x F_d (dscf/MMBtu) x [20.9/(20.9 - O₂, dry)]</i>			
Basis, ppmvd @ 15% O ₂ - provided	3.5	3.5	3.5
Basis, ppmvd - calculated	5.45	5.29	5.02
Moisture Content (%)	11.72	11.85	12.65
Oxygen Content (%)	10.34	10.57	10.86
Oxygen Content, dry (%)	11.71	11.99	12.43
Pollutant Concentration (C_d , lb/dscf)	2.3E-07	2.2E-07	2.1E-07
Dry F Factor for distillate oil (F_d , dscf/MMBtu)	9.190	9.190	9.190
Emission Factor, E (lb/MMBtu)	0.005	0.005	0.005
Heat Input (MMBtu/hr, HHV)	1,707	1,603	1,457
Uncontrolled Emission Rate, (lb/hr)	8.1	7.6	6.9
HRSG Stack ppmvd @ 15% O ₂ - provided	3.5	3.5	3.5
HRSG stack emission rate (lb/hr) - calculated	8.1	7.6	6.9
Particulate from CT and HRSG			
<i>Total PM₁₀ = PM₁₀ (front half) + PM₁₀ ((NH₄)₂SO₄) from Conversion of SO₂ (back-half)</i>			
<i>a. PM₁₀ (front half) (lb/hr)</i>			
CT - provided	17.0	17.0	17.0
<i>b. PM₁₀ ((NH₄)₂SO₄) (back half) = Sulfur trioxide from conversion of SO₂ converts to ammonium sulfate (= PM₁₀)</i>			
<i>Particulate from conversion of SO₂ = SO₂ emissions (lb/hr) x conversion of SO₂ to SO₃ in CT and in SCR x (MW of SO₃/MW of SO₂) x conversion of SO₃ to (NH₄)₂SO₄ x (MW of (NH₄)₂SO₄/MW of SO₃)</i>			
CT SO ₂ emission rate (lb/hr) - calculated	2.7	2.5	2.3
Conversion (%) from SO ₂ to SO ₃ in CT	10.0	10.0	10.0
Remaining SO ₂ (lb/hr) after conversion - calculated	2.4	2.3	2.1
Conversion (%) from SO ₂ to SO ₃ in SCR	3.0	3.0	3.0
MW SO ₂ /MW SO ₃ (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 /MW SO ₃ (132/80)	1.7	1.7	1.7
HRSG Particulate as (NH ₄) ₂ (SO ₄) (lb/hr) - calculated	0.70	0.66	0.60
Total HRSG stack emission rate (lb/hr) [a + b]	17.7	17.7	17.6
Sulfur Dioxide			
<i>SO₂ (lb/hr) = Distillate oil (lb/hr) x sulfur content(%) x (MW SO₂ /MW S)</i>			
CT Fuel use (lb/hr)	89,406	83,952	76,330
Sulfur content (%)	0.0015	0.0015	0.0015
MW SO ₂ /MW S (64/32)	2	2	2
CT emission rate (lb/hr) - calculated	2.7	2.5	2.3
HRSG stack emission rate (lb/hr) - calculated	2.7	2.5	2.3
Sulfuric Acid Mist			
<i>Sulfuric Acid Mist (lb/hr) = SO₂ emission (lb/hr) x Conversion to H₂SO₄ (% by weight)/100 x (MW H₂SO₄ /MW SO₂)</i>			
CT SO ₂ emission rate (lb/hr) - calculated	2.7	2.5	2.3
CT Conversion to H ₂ SO ₄ (% by weight) - provided	10	10	10
SCR SO ₂ (lb/hr)/remaining SO ₂ after conversion - calc	2.4	2.3	2.1
SCR Conversion to H ₂ SO ₄ (% by weight) - provided	3	3	3
MW H ₂ SO ₄ /MW SO ₂ (98/64)	1.53	1.53	1.53
HRSG Stack emission rate (lb/hr)	0.52	0.49	0.45
Lead			
<i>Lead (lb/hr) = Basis (lb/10¹² Btu) x Heat Input (MMBtu/hr) / (10⁶ MMBtu/10¹² Btu)</i>			
Emission Rate Basis (lb/10 ¹² Btu)	14	14	14
Heat Input (MMBtu/hr) (HHV)	1,707	1,603	1,457
HRSG Stack emission rate (lb/hr)	0.024	0.022	0.020

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

Source: Mackinaw Power, 2010; Golder Associates, 2010.

TABLE A-11
DESIGN INFORMATION AND STACK PARAMETERS FOR THE EFFINGHAM PLANT EXPANSION PROJECT
GE FRAME 7FA CT, DISTILLATE FUEL OIL, 50% LOAD

Parameter	CT Only		
	Ambient Temperature/Case No.		
	20 °F Case 24	59 °F Case 25	95 °F Case 26
Case Description	CT	CT	CT
Inlet Chiller (IC) Status	Off	Off	Off
Relative Humidity (%)	60	60	60
<u>Fuel Information</u>			
Fuel heating value (Btu/gal, HHV) - calculated	127,809	127,809	127,809
Fuel density (lb/gal) - typical	6.694	6.694	6.694
Fuel heating value (Btu/lb, HHV) - typical	19,093	19,093	19,093
<u>Combustion Turbine Performance</u>			
Gross power output (MW) - provided	96.7	90.3	79.4
Fuel usage (lb/hr)- provided	69,146	65,534	59,630
Heat Input (MMBtu/hr, HHV) - calculated	1,320	1,251	1,139
Gross heat rate (Btu/kWh, HHV) - calculated	13,653	13,856	14,339
Mass Flow (lb/hr)- provided	2,499,000	2,457,000	2,353,000
<u>CT Exhaust Flow</u>			
CT Exhaust Temperature (°F) - provided	1,200	1,200	1,200
Molecular Weight - provided	28.44	28.40	28.26
Moisture Content (%) - provided	10.19	10.38	11.37
Oxygen Content (%) - provided	11.30	11.54	11.73
Volume flow (acfm) - calculated	1,774,821	1,747,450	1,681,774
<u>HRSG Stack</u>			
Stack Height (ft) - provided	165	165	165
Stack Diameter (ft) - provided	19	19	19
Stack Temperature (°F) - provided	256.0	259.0	268.0
HRSG Volume flow (acfm) - calculated	765,525	756,877	737,549
Velocity (ft/sec)- calculated	45.0	44.5	43.4

Note: Universal gas constant = 1,545.4 ft-lb(force)/°R; atmospheric pressure = 2,116.8 lb(force)/ft²; 14.7 lb/ft².
 Volume flow (acfm) = (mass flow (lb/hr)/molecular weight) x 1545.4 (gas constant, R) x actual temperature (°R)
 / [2116.8 lb/ft² (pressure)] / 60 min/hr

Velocity (ft/sec) = Volume flow (acfm) / [((diameter)² / 4) x 3.14159] / 60 sec/min

Source: Mackinaw Power, 2010, Golder Associates, 2010.

TABLE A-12
MAXIMUM EMISSIONS FOR CRITERIA POLLUTANTS FOR THE EFFINGHAM PLANT EXPANSION PROJECT
GE FRAME 7FA CT, DISTILLATE FUEL OIL, 50% LOAD

Parameter	CT Only		
	Ambient Temperature/Case No.		
	20 °F Case 24	59 °F Case 25	95 °F Case 26
Nitrogen Oxides (NO_x)			
<i>Pollutant Concentration (C_d, lb/dscf) = NO_x (ppmvd) x 46 lb/lb-mole (mole. wgt NO_x) / 385.4 ft³/lb-mole</i>			
<i>NO_x Emission Factor (E, lb/MMBtu) = C_d (lb/dscf) x F_d (dscf/MMBtu) x [20.9/(20.9 - O₂, dry)]</i>			
Basis, ppmvd @ 15% O ₂ - provided	42	42	42
Basis, ppmvd - calculated	58.21	57.12	54.57
Moisture Content (%)	10.19	10.38	11.37
Oxygen Content (%)	11.30	11.54	11.73
Oxygen Content, dry (%)	12.58	12.88	13.23
Pollutant Concentration (C_d , lb/dscf)	7.1E-06	6.8E-06	6.5E-06
Dry F Factor for distillate oil (F_d , dscf/MMBtu)	9.190	9.190	9.190
Emission Factor, E (lb/MMBtu)	0.163	0.163	0.163
Heat Input (MMBtu/hr, HHV)	1,320	1,251	1,139
CT Uncontrolled Emission Rate, (lb/hr)	215.4	204.2	185.8
HRSG Stack ppmvd @ 15% O ₂ - provided	10.0	10.0	10.0
HRSG stack emission rate (lb/hr) - calculated	51.3	48.6	44.2
Carbon Monoxide (CO)			
<i>Pollutant Concentration (C_d, lb/dscf) = CO (ppmd) x 28 lb/lb-mole (mole. wgt CO) / 385.4 ft³/lb-mole</i>			
<i>CO Emission Factor (E, lb/MMBtu) = C_d (lb/dscf) x F_d (dscf/MMBtu) x [20.9/(20.9 - O₂, dry)]</i>			
Basis, ppmvd @ 15% O ₂ - provided	20	20	20
Basis, ppmvd - calculated	28.20	27.20	25.98
Moisture Content (%)	10.19	10.38	11.37
Oxygen Content (%)	11.30	11.54	11.73
Oxygen Content, dry (%)	12.58	12.88	13.23
Pollutant Concentration (C_d , lb/dscf)	2.0E-06	2.0E-06	1.9E-06
Dry F Factor for distillate oil (F_d , dscf/MMBtu)	9.190	9.190	9.190
Emission Factor, E (lb/MMBtu)	0.047	0.047	0.047
Heat Input (MMBtu/hr, HHV)	1,320	1,251	1,139
Uncontrolled Emission Rate, (lb/hr)	62.4	59.2	53.9
HRSG Stack ppmvd @ 15% O ₂ - provided	20.0	20.0	20.0
HRSG stack emission rate (lb/hr) - calculated	62.4	59.2	53.9
Volatile Organic Compounds (VOC)			
<i>Pollutant Concentration (C_d, lb/dscf) = VOC (ppmd) x 16 lb/lb-mole (mole. wgt CH₄) / 385.4 ft³/lb-mole</i>			
<i>VOC Emission Factor (E, lb/MMBtu) = C_d (lb/dscf) x F_d (dscf/MMBtu) x [20.9/(20.9 - O₂, dry)]</i>			
Basis, ppmvd @ 15% O ₂ - provided	3.5	3.5	3.5
Basis, ppmvd - calculated	4.93	4.76	4.55
Moisture Content (%)	10.19	10.38	11.37
Oxygen Content (%)	11.30	11.54	11.73
Oxygen Content, dry (%)	12.58	12.88	13.23
Pollutant Concentration (C_d , lb/dscf)	2.0E-07	2.0E-07	1.9E-07
Dry F Factor for distillate oil (F_d , dscf/MMBtu)	9.190	9.190	9.190
Emission Factor, E (lb/MMBtu)	0.005	0.005	0.005
Heat Input (MMBtu/hr, HHV)	1,320	1,251	1,139
Uncontrolled Emission Rate, (lb/hr)	6.2	5.9	5.4
HRSG Stack ppmvd @ 15% O ₂ - provided	3.5	3.5	3.5
HRSG stack emission rate (lb/hr) - calculated	6.2	5.9	5.4
Particulate from CT and HRSG			
<i>Total PM₁₀ = PM₁₀ (front half) + PM₁₀ ((NH₄)₂SO₄) from Conversion of SO₂ (back-half)</i>			
a. PM ₁₀ (front half) (lb/hr)			
CT - provided	17.0	17.0	17.0
b. PM ₁₀ ((NH ₄) ₂ SO ₄) (back half) = Sulfur trioxide from conversion of SO ₂ converts to ammonium sulfate (= PM ₁₀)			
<i>Particulate from conversion of SO₂ = SO₂ emissions (lb/hr) x conversion of SO₂ to SO₃ in CT and in SCR x (MW of SO₃/MW of SO₂) x conversion of SO₃ to (NH₄)₂SO₄ x (MW of (NH₄)₂SO₄/MW of SO₃)</i>			
CT SO ₂ emission rate (lb/hr) - calculated	2.1	2.0	1.8
Conversion (%) from SO ₂ to SO ₃ in CT	10.0	10.0	10.0
Remaining SO ₂ (lb/hr) after conversion - calculated	1.9	1.8	1.6
Conversion (%) from SO ₂ to SO ₃ in SCR	3.0	3.0	3.0
MW SO ₂ /MW SO ₃ (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 /MW SO ₃ (132/80)	1.7	1.7	1.7
HRSG Particulate as (NH ₄) ₂ (SO ₄) (lb/hr) - calculated	0.54	0.51	0.47
Total HRSG stack emission rate (lb/hr) [a + b]	17.5	17.5	17.5
Sulfur Dioxide			
<i>SO₂ (lb/hr) = Distillate oil (lb/hr) x sulfur content(%) x (MW SO₂ /MW S)</i>			
CT Fuel use (lb/hr)	69,146	65,534	59,630
Sulfur content (%)	0.0015	0.0015	0.0015
MW SO ₂ /MW S (64/32)	2	2	2
CT emission rate (lb/hr) - calculated	2.1	2.0	1.8
HRSG stack emission rate (lb/hr) - calculated	2.1	2.0	1.8
Sulfuric Acid Mist			
<i>Sulfuric Acid Mist (lb/hr) = SO₂ emission (lb/hr) x Conversion to H₂SO₄ (% by weight)/100 x (MW H₂SO₄ /MW SO₂)</i>			
CT SO ₂ emission rate (lb/hr) - calculated	2.1	2.0	1.8
CT Conversion to H ₂ SO ₄ (% by weight) - provided	10	10	10
SCR SO ₂ (lb/hr) (remaining SO ₂ after conversion) - calc	1.9	1.8	1.6
SCR Conversion to H ₂ SO ₄ (% by weight) - provided	3	3	3
MW H ₂ SO ₄ /MW SO ₂ (98/64)	1.53	1.53	1.53
HRSG Stack emission rate (lb/hr)	0.40	0.38	0.35
Lead			
<i>Lead (lb/hr) = Basis (lb/10¹² Btu) x Heat Input (MMBtu/hr) / (10⁶ MMBtu/10¹² Btu)</i>			
Emission Rate Basis (lb/10 ¹² Btu)	14	14	14
Heat Input (MMBtu/hr) (HHV)	1,320	1,251	1,139
HRSG Stack emission rate (lb/hr)	0.018	0.018	0.016

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

Source: Mackinaw Power, 2010; Golder Associates, 2010.

TABLE A-13
REGULATED AND HAZARDOUS AIR POLLUTANT EMISSION FACTORS AND EMISSIONS
FOR THE COMBUSTION TURBINE AND DUCT BURNER WITH NATURAL GAS COMBUSTION
EFFINGHAM PLANT EXPANSION PROJECT

Pollutant	Combustion Turbine Natural Gas ^a				Duct Burner Natural Gas ^a				CT With Duct Burner
	Emission Rate				Emission Rate				Emission Rate
	Ref.	Factor	Units	lb/hr	Ref.	Factor	Units	lb/hr	lb/hr
1,3-Butadiene	b,d	4.30E-07	lb/MMBtu	7.99E-04	--	--	0.00E+00		7.99E-04
Acetaldehyde	b	4.00E-05	lb/MMBtu	7.43E-02	--	--	0.00E+00		7.43E-02
Acrolein	b	6.40E-06	lb/MMBtu	1.19E-02	--	--	0.00E+00		1.19E-02
Ammonia	h	2.08E-02	lb/MMBtu	3.87E+01	--	--	0.00E+00		3.87E+01
Benzene	b	1.20E-05	lb/MMBtu	2.23E-02	c	2.10E-03	lb/MMCF	9.40E-04	2.32E-02
Ethylbenzene	b	3.20E-05	lb/MMBtu	5.95E-02	--	--	0.00E+00		5.95E-02
Formaldehyde	f	2.11E-04	lb/MMBtu	3.92E-01	c	7.50E-02	lb/MMCF	3.36E-02	4.25E-01
Polycyclic Aromatic Hydrocarbons (PAH)	b	2.20E-06	lb/MMBtu	4.09E-03	--	--	0.00E+00		4.09E-03
Propylene Oxide	b,d	2.90E-05	lb/MMBtu	5.39E-02	--	--	0.00E+00		5.39E-02
Toluene	b	1.30E-04	lb/MMBtu	2.42E-01	c	3.40E-03	lb/MMCF	1.52E-03	2.43E-01
Xylene	b	6.40E-05	lb/MMBtu	1.19E-01	--	--	0.00E+00		1.19E-01
7,12-Dimethylbenz(a)anthracene	--	--	--	0.00E+00	c,d	1.60E-05	lb/MMCF	7.16E-06	7.16E-06
Hexane	--	--	--	0.00E+00	e	1.30E-03	lb/MMCF	5.82E-04	5.82E-04
Arsenic	--	--	--	0.00E+00	c	2.00E-04	lb/MMCF	8.95E-05	8.95E-05
Beryllium	--	--	--	0.00E+00	c,d	1.20E-05	lb/MMCF	5.37E-06	5.37E-06
Cadmium	--	--	--	0.00E+00	c	1.10E-03	lb/MMCF	4.92E-04	4.92E-04
Chromium	--	--	--	0.00E+00	c	1.40E-03	lb/MMCF	6.27E-04	6.27E-04
Cobalt	--	--	--	0.00E+00	c	8.40E-05	lb/MMCF	3.76E-05	3.76E-05
Lead	--	--	--	0.00E+00	c	5.00E-04	lb/MMCF	2.24E-04	2.24E-04
Manganese	--	--	--	0.00E+00	c	3.80E-04	lb/MMCF	1.70E-04	1.70E-04
Mercury	--	--	--	0.00E+00	c	2.60E-04	lb/MMCF	1.16E-04	1.16E-04
Nickel	--	--	--	0.00E+00	c	2.10E-03	lb/MMCF	9.40E-04	9.40E-04
Selenium	--	--	--	0.00E+00	c,d	2.40E-05	lb/MMCF	1.07E-05	1.07E-05
Polycyclic Organic Matters (POMs)									
Acenaphthene	--	--	--	--	c,d	1.80E-06	lb/MMCF	--	--
Acenaphthylene	--	--	--	--	c,d	1.80E-06	lb/MMCF	--	--
Anthracene	--	--	--	--	c,d	2.40E-06	lb/MMCF	--	--
Benz(a)anthracene	--	--	--	--	c,d	1.80E-06	lb/MMCF	--	--
Benzo(a)pyrene	--	--	--	--	c,d	1.20E-06	lb/MMCF	--	--
Benzo(b)fluoranthene	--	--	--	--	c,d	1.80E-06	lb/MMCF	--	--
Benzo(g,h,i)perylene	--	--	--	--	c,d	1.20E-06	lb/MMCF	--	--
Benzo(k)fluoranthene	--	--	--	--	c,d	1.80E-06	lb/MMCF	--	--
Chrysene	--	--	--	--	c,d	1.80E-06	lb/MMCF	--	--
Dibenzo(a,h)anthracene	--	--	--	--	c,d	1.20E-06	lb/MMCF	--	--
Dichlorobenzene	--	--	--	--	c	1.20E-03	lb/MMCF	--	--
Fluoranthene	--	--	--	--	c	3.00E-06	lb/MMCF	--	--
Fluorene	--	--	--	--	c	2.80E-06	lb/MMCF	--	--
Indeno(1,2,3-cd)pyrene	--	--	--	--	c,d	1.80E-06	lb/MMCF	--	--
2-Methylnaphthalene	--	--	--	--	c	2.40E-05	lb/MMCF	--	--
3-Methylchloranthrene	--	--	--	--	c,d	1.80E-06	lb/MMCF	--	--
Naphthalene	b, g	1.30E-06	lb/MMBtu	2.42E-03	c	6.10E-04	lb/MMCF	2.73E-04	2.69E-03
Phenanthrene	--	--	--	--	c	1.70E-05	lb/MMCF	--	--
Pyrene	--	--	--	--	c	5.00E-06	lb/MMCF	--	--
Total POMs		1.30E-06	lb/MMBtu	2.42E-03		1.88E-03	lb/MMCF	8.43E-04	3.26E-03
				CT Total HAPs =					CT+DB Total HAPs =
				CT Max. Individual HAP =					CT+DB Max. Individual HAP =
				0.98					1.02
				0.39					0.43

^a Emissions based on:

Fuel	Natural gas
Heat input (MMBtu/hr) (HHV)	CT Only 1,859 Baseload at 59 F.
	Duct Burner 470
Total heat input (MMBtu/hr)	CT + DB 2,329
Duct burner fuel flow (MMft ³ /hr)	0.448
Annual operating hours	CT 8,760
	Duct Burner 4,000

^b Emission factor from Table 3.1-3, AP-42, EPA, April 2000.

^c Emission factor from Tables 1.4.-2, 1.4.-3, and 1.4.-4, AP-42, EPA, July 1998.

^d Based on the method detection limit; for the CT, based on 1/2 of the method detection limit; expected emissions are lower.

^e Emission factor from "AB 2588 Combustion Emission Factors", Ventura County Air Pollution Control District, Ventura, CA 2001.

^f Formaldehyde emission factor based on 91 ppb @15% O₂ equivalent to combustion turbine MACT limit, not an applicable standard for this project (see Table A-13a).

^g Part of Polycyclic Organic Matters (POMs) and also a regulated HAP by itself.

^h Ammonia emission factor based on industry standard ammonia slip of 9 ppmv @15% O₂ (see Table A-13a). Ammonia is not a HAP.

TABLE A-13a
MAXIMUM FORMALDEHYDE AND AMMONIA EMISSIONS
FOR THE EFFINGHAM PLANT EXPANSION PROJECT

		Ambient Temperature/Case No.	
		CT Only- Base Load	CT Only- Base Load
		Natural Gas	Fuel Oil
Parameter	Units	59 °F	59 °F
		Case 2	Case 16
Formaldehyde (CH₂O) (MW = 30)			
$CH_2O \text{ (lb/hr)} = CH_2O \text{ (ppmvd actual)} \times \text{Volume flow (acfm, dry)} \times 30 \text{ (mole. wgt } CH_2O) \times 2116.8 \text{ lb/ft}^2$ $\text{(pressure)} / [1545.7 \text{ (gas constant, R)} \times \text{Actual Temp. (°R)}] \times 60 \text{ min/hr}$ $CH_2O \text{ (ppmv actual)} = CH_2O \text{ (ppmd @ 15\%O}_2) \times [(20.9 - O_2 \text{ dry})/(20.9 - 15)] \times (1 - \text{Moisture}(\%)/100)$ $\text{Oxygen (\%, dry)}(O_2 \text{ dry}) = \text{Oxygen (\%)} / (1 - \text{Moisture (\%)})$			
Basis- actual	ppmv	0.101	0.114
Basis- assumed ^a	ppmvd @15% O2	0.091	0.091
Moisture	%	8.37	11.46
Oxygen	%	12.57	11.11
Oxygen	% dry	13.72	12.55
Exhaust Flow	acfm	1,036,233	1,222,181
Exhaust Temperature	°F	202	294
CT Emission rate	lb/hr	0.392	0.456
Heat Input	MMBtu/hr	1,859	1,962
CT Emission rate (HHV)	lb/10 ¹² Btu	210.8	232.5
Ammonia (NH₃) (MW = 17)			
$NH_3 \text{ (lb/hr)} = NH_3 \text{ (ppmvd actual)} \times \text{Volume flow (acfm, dry)} \times 17 \text{ (mole. wgt } NH_3) \times 2116.8 \text{ lb/ft}^2$ $\text{(pressure)} / [1545.7 \text{ (gas constant, R)} \times \text{Actual Temp. (°R)}] \times 60 \text{ min/hr}$ $NH_3 \text{ (ppmv actual)} = NH_3 \text{ (ppmd @ 15\%O}_2) \times [(20.9 - O_2 \text{ dry})/(20.9 - 15)] \times (1 - \text{Moisture}(\%)/100)$ $\text{Oxygen (\%, dry)}(O_2 \text{ dry}) = \text{Oxygen (\%)} / (1 - \text{Moisture (\%)})$			
Basis- actual	ppmv	10.04	11.28
Basis- (Industry Standard)	ppmvd @15% O2	9	9
Moisture	%	8.37	11.46
Oxygen	%	12.57	11.11
Oxygen	% dry	13.72	12.55
Exhaust Flow	acfm	1,036,233	1,222,181
Exhaust Temperature	°F	202	294
CT Emission rate	lb/hr	38.7	45.1
Heat Input	MMBtu/hr	1,859	1,962
CT Emission rate (HHV)	lb/MMBtu	0.021	0.023

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

^a Emission factor is equivalent to combustion turbine MACT limit (not an applicable standard for this project).

Source: Mackinaw Power, 2010; Golder Associates, 2010.

TABLE A-14
REGULATED AND HAZARDOUS AIR POLLUTANT EMISSION FACTORS AND EMISSIONS
FOR THE COMBUSTION TURBINE AND DUCT BURNER WITH FUEL OIL AND NATURAL GAS COMBUSTION
EFFINGHAM PLANT EXPANSION PROJECT

Pollutant	Ref.	Combustion Turbine			CT Only ^f	CT with DB ^f	Annual Emissions (TPY) ^g			
		Fuel Oil ^a		Emission Rate	Natural Gas	Natural Gas	Scenario 1	Scenario 2	Maximum	Maximum
		Emission Factor	Units		Emission Rate			CT NG & FO	CT NG	
		lb/hr	lb/hr	lb/hr	with DB NG	with DB NG	1 CT/DB	2 CT/DB		
1,3-Butadiene	b,d	1.60E-05	lb/MMBtu	3.14E-02	7.99E-04	7.99E-04	1.88E-02	3.50E-03	1.9E-02	3.8E-02
Acetaldehyde		--	--	0.00E+00	7.43E-02	7.43E-02	2.88E-01	3.26E-01	3.3E-01	6.5E-01
Acrolein		--	--	0.00E+00	1.19E-02	1.19E-02	4.62E-02	5.21E-02	5.2E-02	1.0E-01
Ammonia	i	2.30E-02	lb/MMBtu	4.51E+01	3.87E+01	3.87E+01	1.73E+02	1.70E+02	1.7E+02	3.5E+02
Benzene	b	5.50E-05	lb/MMBtu	1.08E-01	2.23E-02	2.32E-02	1.42E-01	9.96E-02	1.4E-01	2.8E-01
Ethylbenzene		--	--	0.00E+00	5.95E-02	5.95E-02	2.31E-01	2.60E-01	2.6E-01	5.2E-01
Formaldehyde	h	2.32E-04	lb/MMBtu	4.56E-01	3.92E-01	4.25E-01	1.82E+00	1.78E+00	1.8E+00	3.6E+00
Polycyclic Aromatic Hydrocarbons (PAH)	b	4.00E-05	lb/MMBtu	7.85E-02	4.09E-03	4.09E-03	5.51E-02	1.79E-02	5.5E-02	1.1E-01
Propylene Oxide		--	--	0.00E+00	5.39E-02	5.39E-02	2.09E-01	2.36E-01	2.4E-01	4.7E-01
Toluene		--	--	0.00E+00	2.42E-01	2.43E-01	9.40E-01	1.06E+00	1.1E+00	2.1E+00
Xylene		--	--	0.00E+00	1.19E-01	1.19E-01	4.62E-01	5.21E-01	5.2E-01	1.0E+00
7,12-Dimethylbenz(a)anthracene		--	--	0.00E+00	0.00E+00	7.16E-06	1.43E-05	1.43E-05	1.4E-05	2.9E-05
Hexane		--	--	0.00E+00	0.00E+00	5.82E-04	1.16E-03	1.16E-03	1.2E-03	2.3E-03
Arsenic	c,d	1.10E-05	lb/MMBtu	2.16E-02	0.00E+00	8.95E-05	1.10E-02	1.79E-04	1.1E-02	2.2E-02
Beryllium	c,d	3.10E-07	lb/MMBtu	6.08E-04	0.00E+00	5.37E-06	3.15E-04	1.07E-05	3.1E-04	6.3E-04
Cadmium	c	4.80E-06	lb/MMBtu	9.42E-03	0.00E+00	4.92E-04	5.69E-03	9.85E-04	5.7E-03	1.1E-02
Chromium	c	1.10E-05	lb/MMBtu	2.16E-02	0.00E+00	6.27E-04	1.20E-02	1.25E-03	1.2E-02	2.4E-02
Cobalt		--	--	0.00E+00	0.00E+00	3.76E-05	7.52E-05	7.52E-05	7.5E-05	1.5E-04
Lead	c	1.40E-05	lb/MMBtu	2.75E-02	0.00E+00	2.24E-04	1.42E-02	4.48E-04	1.4E-02	2.8E-02
Manganese	c	7.90E-04	lb/MMBtu	1.55E+00	0.00E+00	1.70E-04	7.75E-01	3.40E-04	7.8E-01	1.6E+00
Mercury	c	1.20E-06	lb/MMBtu	2.35E-03	0.00E+00	1.16E-04	1.41E-03	2.33E-04	1.4E-03	2.8E-03
Nickel	c,d	4.60E-06	lb/MMBtu	9.03E-03	0.00E+00	9.40E-04	6.39E-03	1.88E-03	6.4E-03	1.3E-02
Selenium	c,d	2.50E-05	lb/MMBtu	4.91E-02	0.00E+00	1.07E-05	2.45E-02	2.15E-05	2.5E-02	4.9E-02
Polycyclic Organic Matters (POMs)										
Acenaphthene		--	--	0.00E+00	0.00E+00	--	--	--	--	--
Acenaphthylene		--	--	0.00E+00	0.00E+00	--	--	--	--	--
Anthracene		--	--	0.00E+00	0.00E+00	--	--	--	--	--
Benz(a)anthracene		--	--	0.00E+00	0.00E+00	--	--	--	--	--
Benzo(a)pyrene		--	--	0.00E+00	0.00E+00	--	--	--	--	--
Benzo(b)fluoranthene		--	--	0.00E+00	0.00E+00	--	--	--	--	--
Benzo(g,h,i)perylene		--	--	0.00E+00	0.00E+00	--	--	--	--	--
Benzo(k)fluoranthene		--	--	0.00E+00	0.00E+00	--	--	--	--	--
Chrysene		--	--	0.00E+00	0.00E+00	--	--	--	--	--
Dibenzo(a,h)anthracene		--	--	0.00E+00	0.00E+00	--	--	--	--	--
Dichlorobenzene		--	--	0.00E+00	0.00E+00	--	--	--	--	--
Fluoranthene		--	--	0.00E+00	0.00E+00	--	--	--	--	--
Fluorene		--	--	0.00E+00	0.00E+00	--	--	--	--	--
Indeno(1,2,3-cd)pyrene		--	--	0.00E+00	0.00E+00	--	--	--	--	--
2-Methylnaphthalene		--	--	0.00E+00	0.00E+00	--	--	--	--	--
3-Methylchloranthrene		--	--	0.00E+00	0.00E+00	--	--	--	--	--
Naphthalene	b,e	3.50E-05	lb/MMBtu	6.87E-02	2.42E-03	2.69E-03	4.43E-02	1.11E-02	4.4E-02	8.9E-02
Phenanthrene		--	--	0.00E+00	0.00E+00	--	--	--	--	--
Pyrene		--	--	0.00E+00	0.00E+00	--	--	--	--	--
Total POMs		3.50E-05	lb/MMBtu	6.87E-02	2.42E-03	3.26E-03	4.54E-02	1.23E-02	4.5E-02	9.1E-02
CT+DB Total HAPs =							5.1	4.4	5.4	10.8
CT+DB Max. Individual HAP =							1.8	1.8	1.8	3.6

**TABLE A-15
REGULATED AND HAZARDOUS AIR POLLUTANT EMISSION FACTORS AND EMISSIONS
FOR THE EFFINGHAM PLANT EXPANSION PROJECT
INCLUDING THE FUEL HEATER AND AUXILIARY BOILER**

Pollutant	Ref.	Emission Factor	Units	Natural Gas Combustion				CT/DB ^g	PROJECT
				Fuel Heater ^a		Auxiliary Boiler ^b		Maximum	TOTAL
				Emission Rate		Emission Rate		Emission Rate	Emission Rate
				lb/hr	TPY	lb/hr	TPY	TPY	TPY
1,3-Butadiene		--	--	--	--	--	--	3.76E-02	3.76E-02
Acetaldehyde		--	--	--	--	--	--	6.51E-01	6.51E-01
Acrolein		--	--	--	--	--	--	1.04E-01	1.04E-01
Ammonia ^h		--	--	--	--	--	--	3.46E+02	3.46E+02
Benzene	c	2.10E-03	lb/MMCF	1.75E-05	7.67E-05	3.40E-05	4.25E-05	2.85E-01	2.85E-01
Ethylbenzene		--	--	--	--	--	--	5.21E-01	5.21E-01
Formaldehyde	c	7.50E-02	lb/MMCF	6.25E-04	2.74E-03	1.21E-03	1.52E-03	3.63E+00	3.63E+00
Polycyclic Aromatic Hydrocarbons (PAH)		--	--	--	--	--	--	1.10E-01	1.10E-01
Propylene Oxide		--	--	--	--	--	--	4.72E-01	4.72E-01
Toluene	c	3.40E-03	lb/MMCF	2.83E-05	1.24E-04	5.50E-05	6.88E-05	2.12E+00	2.12E+00
Xylene		--	--	--	--	--	--	1.04E+00	1.04E+00
7,12-Dimethylbenz(a)anthracene	c,d	1.60E-05	lb/MMCF	1.33E-07	5.84E-07	2.59E-07	3.24E-07	2.86E-05	2.96E-05
Hexane	e	1.30E-03	lb/MMCF	1.08E-05	4.75E-05	2.10E-05	2.63E-05	2.33E-03	2.40E-03
Arsenic	c	2.00E-04	lb/MMCF	1.67E-06	7.30E-06	3.24E-06	4.05E-06	2.19E-02	2.20E-02
Beryllium	c,d	1.20E-05	lb/MMCF	1.00E-07	4.38E-07	1.94E-07	2.43E-07	6.30E-04	6.30E-04
Cadmium	c	1.10E-03	lb/MMCF	9.17E-06	4.02E-05	1.78E-05	2.23E-05	1.14E-02	1.14E-02
Chromium	c	1.40E-03	lb/MMCF	1.17E-05	5.11E-05	2.27E-05	2.83E-05	2.41E-02	2.42E-02
Cobalt	c	8.40E-05	lb/MMCF	7.00E-07	3.07E-06	1.36E-06	1.70E-06	1.50E-04	1.55E-04
Lead	c	5.00E-04	lb/MMCF	4.17E-06	1.83E-05	8.10E-06	1.01E-05	2.84E-02	2.84E-02
Manganese	c	3.80E-04	lb/MMCF	3.17E-06	1.39E-05	6.15E-06	7.69E-06	1.55E+00	1.55E+00
Mercury	c	2.60E-04	lb/MMCF	2.17E-06	9.49E-06	4.21E-06	5.26E-06	2.82E-03	2.83E-03
Nickel	c	2.10E-03	lb/MMCF	1.75E-05	7.67E-05	3.40E-05	4.25E-05	1.28E-02	1.29E-02
Selenium	c,d	2.40E-05	lb/MMCF	2.00E-07	8.76E-07	3.89E-07	4.86E-07	4.91E-02	4.91E-02
Polycyclic Organic Matters (POMs)									
Acenaphthene	c,d	1.80E-06	lb/MMCF	--	--	--	--	--	--
Acenaphthylene	c,d	1.80E-06	lb/MMCF	--	--	--	--	--	--
Anthracene	c,d	2.40E-06	lb/MMCF	--	--	--	--	--	--
Benz(a)anthracene	c,d	1.80E-06	lb/MMCF	--	--	--	--	--	--
Benzo(a)pyrene	c,d	1.20E-06	lb/MMCF	--	--	--	--	--	--
Benzo(b)fluoranthene	c,d	1.80E-06	lb/MMCF	--	--	--	--	--	--
Benzo(g,h,i)perylene	c,d	1.20E-06	lb/MMCF	--	--	--	--	--	--
Benzo(k)fluoranthene	c,d	1.80E-06	lb/MMCF	--	--	--	--	--	--
Chrysene	c,d	1.80E-06	lb/MMCF	--	--	--	--	--	--
Dibenzo(a,h)anthracene	c,d	1.20E-06	lb/MMCF	--	--	--	--	--	--
Dichlorobenzene	c	1.20E-03	lb/MMCF	--	--	--	--	--	--
Fluoranthene	c	3.00E-06	lb/MMCF	--	--	--	--	--	--
Fluorene	c	2.80E-06	lb/MMCF	--	--	--	--	--	--
Indeno(1,2,3-cd)pyrene	c,d	1.80E-06	lb/MMCF	--	--	--	--	--	--
2-Methylnaphthalene	c	2.40E-05	lb/MMCF	--	--	--	--	--	--
3-Methylchloranthrene	c,d	1.80E-06	lb/MMCF	--	--	--	--	--	--
Naphthalene	c,f	6.10E-04	lb/MMCF	5.08E-06	2.23E-05	9.88E-06	1.23E-05	8.85E-02	8.85E-02
Phenanthrene	c	1.70E-05	lb/MMCF	--	--	--	--	--	--
Pyrene	c	5.00E-06	lb/MMCF	--	--	--	--	--	--
Total POMs		1.88E-03	lb/MMCF	1.57E-05	6.87E-05	3.05E-05	3.81E-05	9.08E-02	9.09E-02
CT Total HAPs =				7.48E-04	3.28E-03	1.45E-03	1.82E-03	10.8	10.8
CT+DB Max. Individual HAP =				6.25E-04	2.74E-03	1.21E-03	1.52E-03	3.63	3.63

^a Based on heat input rate (MMBtu/hr) = 8.75 ; annual operating hours = 8,760
Fuel flow (MMft³/hr) 0.00833

^b Based on heat input rate (MMBtu/hr) = 17 ; annual operating hours = 2,500
Fuel flow (MMft³/hr) 0.016

^c Emission factor from Tables 1.4-2, 1.4-3, and 1.4-4, AP-42, EPA, July 1998.

^d Based on the method detection limit; expected emissions are lower.

^e Emission factor from "AB 2588 Combustion Emission Factors", Ventura County Air Pollution Control District, Ventura, CA 2001.

^f Part of Polycyclic Organic Matters (POMs) and also a regulated HAP by itself.

^g See Table A-14 for the maximum emissions from the CT and DB.

^h Ammonia is not a HAP.

TABLE A-16
COOLING TOWER EMISSIONS CALCULATION
EFFINGHAM PLANT EXPANSION PROJECT

Cooling Tower Reference Data					
Water Circulation Rate		Annual Operating Hrs.	Drift (%)	TDS (ppmw)	TDS Specific Gravity ^a
gal/min	lb/hr				
155,000	77,562,000	8,760	0.001	1,000	2.2

^a TDS specific gravity corresponding to NaCl.

Calculations

Cooling Tower Particulate Emissions Size Distribution

$$\text{Volume of drift droplet} = (4/3)\pi(D_d/2)^3$$

$$\text{Droplet mass} = (\text{Volume of drift droplet})(\rho_w)$$

$$\text{Mass of solids in drift droplet} = (\text{TDS})(\rho_w)(\text{Volume of drift droplet})$$

$$\text{Solid particle volume} = (\text{Particle mass of solids}) / (\rho_{\text{TDS}})$$

$$D_p = D_d [(TDS)(\rho_w/\rho_{\text{TDS}})]^{1/3}$$

where:

D_p = diameter of solid particle (μm)

TDS = total dissolved solids content (ppmw)

D_d = diameter of drift droplet (μm)

ρ_w = density of water = 1E-6 ug/mm³

ρ_{TDS} = density of solid particles (assume NaCl)

Size Distribution for Cooling Tower Particulate Emissions ^b						
Droplet Diameter (μm)	Droplet Volume (μm^3)	Droplet Mass (μg)	Particle Mass (Solids) (μg)	Solid Particle Volume (μm^3)	Solid Particle	
					Diameter (μm)	% Mass Smaller
10	524	5.24E-04	5.24.E-07	0.24	0.77	0.00
20	4,189	4.19E-03	4.19.E-06	1.90	1.54	0.20
30	14,137	1.41E-02	1.41.E-05	6.4	2.31	0.23
40	33,510	3.35E-02	3.35.E-05	15.2	3.08	0.51
50	65,450	6.54E-02	6.54.E-05	30	3.84	1.82
60	113,097	1.13E-01	1.13.E-04	51	4.61	5.70
70	179,594	1.80E-01	1.80.E-04	82	5.38	21.35
90	381,704	3.82E-01	3.82.E-04	174	6.9	49.81
110	696,910	6.97E-01	6.97.E-04	317	8.5	70.51
130	1,150,347	1.15E+00	1.15.E-03	523	10.0	82.02
150	1,767,146	1.77E+00	1.77.E-03	803	11.5	88.01
180	3,053,628	3.05E+00	3.05.E-03	1,388	13.8	91.03
210	4,849,048	4.85E+00	4.85.E-03	2,204	16.1	92.47
240	7,238,229	7.24E+00	7.24.E-03	3,290	18.5	94.09
270	10,305,995	1.03E+01	1.03.E-02	4,685	20.8	94.69
300	14,137,167	1.41E+01	1.41.E-02	6,426	23.1	96.29
350	22,449,298	2.24E+01	2.24.E-02	10,204	26.9	97.01
400	33,510,322	3.35E+01	3.35.E-02	15,232	30.8	98.34
450	47,712,938	4.77E+01	4.77.E-02	21,688	34.6	99.07
500	65,449,847	6.54E+01	6.54.E-02	29,750	38.4	99.07
600	113,097,336	1.13E+02	1.13.E-01	51,408	46.1	100.00

^b Methodology from Reisman, J. and Frisbie, G., "Calculating Realistic PM10 Emissions from Cooling Towers." Droplet diameter and % mass smaller values from site-specific vendor data.

Particulate Emission Rates

$$\text{PM Emission Rate} = \text{Water Circulation Rate (lb/hr)} \times \text{Drift} \times \text{TDS} / 1,000,000$$

$$\text{PM}_{10} \text{ Emission Rate} = \text{PM Emission Rate} \times \text{PM}_{10} \text{ Fraction}$$

$$\text{PM}_{2.5} \text{ Emission Rate} = \text{PM Emission Rate} \times \text{PM}_{2.5} \text{ Fraction}$$

$$\text{Annual Emission Rates (tons/yr)} = \text{Short-term Emission Rates (lbs/hr)} \times 8,760 \text{ hours/year} / 2,000 \text{ lbs per ton}$$

Particulate Emission Rates ^c		
Pollutant	Units	Value
PM	lb/hr	0.78
	TPY	3.40
PM ₁₀	%PM	76.1
	lb/hr	0.59
PM _{2.5}	TPY	2.58
	%PM	0.30
	lb/hr	0.0023
	TPY	0.0101

^c PM₁₀ and PM_{2.5} fractions interpolated from size distribution.

**TABLE A-17
COOLING TOWER EMISSIONS CALCULATION FOR INLET CHILLER
EFFINGHAM PLANT EXPANSION PROJECT**

Cooling Tower Reference Data					
Water Circulation Rate		Annual Operating Hrs.	Drift (%)	TDS (ppmw)	TDS Specific Gravity ^a
gal/min	lb/hr				
10,042	5,025,017	8,760	0.001	1,000	2.2

^a TDS specific gravity corresponding to NaCl.

Calculations

Cooling Tower Particulate Emissions Size Distribution

$$\text{Volume of drift droplet} = (4/3)\pi(D_d/2)^3$$

$$\text{Droplet mass} = (\text{Volume of drift droplet})(\rho_w)$$

$$\text{Mass of solids in drift droplet} = (\text{TDS})(\rho_w)(\text{Volume of drift droplet})$$

$$\text{Solid particle volume} = (\text{Particle mass of solids}) / (\rho_{\text{TDS}})$$

$$D_o = D_d [(TDS)(\rho_w/\rho_{\text{TDS}})]^{1/3}$$

where:

D_p = diameter of solid particle (μm)

D_d = diameter of drift droplet (μm)

TDS = total dissolved solids content (ppmw)

ρ_w = density of water = $1\text{E-}6 \text{ ug/mm}^3$

ρ_{TDS} = density of solid particles (assume NaCl)

Size Distribution for Cooling Tower Particulate Emissions ^b						
Droplet Diameter (μm)	Droplet Volume (μm^3)	Droplet Mass (μg)	Particle Mass (Solids) (μg)	Solid Particle Volume (μm^3)	Solid Particle	
					Diameter (μm)	% Mass Smaller
10	524	5.24E-04	5.24E-07	0.24	0.77	0.00
20	4,189	4.19E-03	4.19E-06	1.90	1.54	0.20
30	14,137	1.41E-02	1.41E-05	6.4	2.31	0.23
40	33,510	3.35E-02	3.35E-05	15.2	3.08	0.51
50	65,450	6.54E-02	6.54E-05	30	3.84	1.82
60	113,097	1.13E-01	1.13E-04	51	4.61	5.70
70	179,594	1.80E-01	1.80E-04	82	5.38	21.35
90	381,704	3.82E-01	3.82E-04	174	6.9	49.81
110	696,910	6.97E-01	6.97E-04	317	8.5	70.51
130	1,150,347	1.15E+00	1.15E-03	523	10.0	82.02
150	1,767,146	1.77E+00	1.77E-03	803	11.5	88.01
180	3,053,628	3.05E+00	3.05E-03	1,388	13.8	91.03
210	4,849,048	4.85E+00	4.85E-03	2,204	16.1	92.47
240	7,238,229	7.24E+00	7.24E-03	3,290	18.5	94.09
270	10,305,995	1.03E+01	1.03E-02	4,685	20.8	94.69
300	14,137,167	1.41E+01	1.41E-02	6,426	23.1	96.29
350	22,449,298	2.24E+01	2.24E-02	10,204	26.9	97.01
400	33,510,322	3.35E+01	3.35E-02	15,232	30.8	98.34
450	47,712,938	4.77E+01	4.77E-02	21,688	34.6	99.07
500	65,449,847	6.54E+01	6.54E-02	29,750	38.4	99.07
600	113,097,336	1.13E+02	1.13E-01	51,408	46.1	100.00

^b Methodology from Reisman, J. and Frisbie, G., "Calculating Realistic PM10 Emissions from Cooling Towers." Droplet diameter and % mass smaller values from site-specific vendor data.

Particulate Emission Rates

$$\text{PM Emission Rate} = \text{Water Circulation Rate (lb/hr)} \times \text{Drift} \times \text{TDS} / 1,000,000$$

$$\text{PM}_{10} \text{ Emission Rate} = \text{PM Emission Rate} \times \text{PM}_{10} \text{ Fraction}$$

$$\text{PM}_{2.5} \text{ Emission Rate} = \text{PM Emission Rate} \times \text{PM}_{2.5} \text{ Fraction}$$

$$\text{Annual Emission Rates (tons/yr)} = \text{Short-term Emission Rates (lbs/hr)} \times 8,760 \text{ hours/year} / 2,000 \text{ lbs per ton}$$

Particulate Emission Rates ^c		
Pollutant	Units	Value
PM	lb/hr	0.05
	TPY	0.22
PM ₁₀	%PM	76.1
	lb/hr	0.04
PM _{2.5}	TPY	0.17
	%PM	0.30
	lb/hr	0.0001
	TPY	0.0007

^c PM₁₀ and PM_{2.5} fractions interpolated from size distribution.

TANKS 4.0.9d
Emissions Report - Detail Format
Tank Identification and Physical Characteristics

Identification

User Identification:	Effingham rev2
City:	Rincon
State:	Georgia
Company:	
Type of Tank:	Vertical Fixed Roof Tank
Description:	

Tank Dimensions

Shell Height (ft):	50.00
Diameter (ft):	90.00
Liquid Height (ft) :	49.50
Avg. Liquid Height (ft):	49.50
Volume (gallons):	2,379,458.31
Turnovers:	14.00
Net Throughput(gal/yr):	32,700,000.00
Is Tank Heated (y/n):	N

Paint Characteristics

Shell Color/Shade:	White/White
Shell Condition	Good
Roof Color/Shade:	White/White
Roof Condition:	Good

Roof Characteristics

Type:	Dome
Height (ft)	0.00
Radius (ft) (Dome Roof)	0.00

Breather Vent Settings

Vacuum Settings (psig):	-0.03
Pressure Settings (psig)	0.03

Meteorological Data used in Emissions Calculations: Savannah, Georgia (Avg Atmospheric Pressure = 14.75 psia)

TANKS 4.0.9d
Emissions Report - Detail Format
Liquid Contents of Storage Tank

Effingham rev2 - Vertical Fixed Roof Tank
Rincon, Georgia

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F)			Liquid Bulk Temp (deg F)	Vapor Pressure (psia)			Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
		Avg.	Min.	Max.		Avg.	Min.	Max.					
Distillate fuel oil no. 2	All	68.26	62.83	73.68	66.30	0.0086	0.0072	0.0101	130.0000			188.00	Option 1: VP60 = .0065 VP70 = .009

TANKS 4.0.9d

Emissions Report - Detail Format

Detail Calculations (AP-42)

Effingham rev2 - Vertical Fixed Roof Tank Rincon, Georgia

Annual Emission Calculations

Standing Losses (lb):	113.0711
Vapor Space Volume (cu ft):	42,452.6886
Vapor Density (lb/cu ft):	0.0002
Vapor Space Expansion Factor:	0.0372
Vented Vapor Saturation Factor:	0.9970

Tank Vapor Space Volume:	
Vapor Space Volume (cu ft):	42,452.6886
Tank Diameter (ft):	90.0000
Vapor Space Outage (ft):	6.6731
Tank Shell Height (ft):	50.0000
Average Liquid Height (ft):	49.5000
Roof Outage (ft):	6.1731

Roof Outage (Dome Roof)	
Roof Outage (ft):	6.1731
Dome Radius (ft):	90.0000
Shell Radius (ft):	45.0000

Vapor Density	
Vapor Density (lb/cu ft):	0.0002
Vapor Molecular Weight (lb/lb-mole):	130.0000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0086
Daily Avg. Liquid Surface Temp. (deg. R):	527.9279
Daily Average Ambient Temp. (deg. F):	66.2833
Ideal Gas Constant R (psia cu ft / (lb-mol-deg R)):	10.731
Liquid Bulk Temperature (deg. R):	525.9733
Tank Paint Solar Absorptance (Shell):	0.1700
Tank Paint Solar Absorptance (Roof):	0.1700
Daily Total Solar Insulation Factor (Btu/sqft day):	1,461.9273

Vapor Space Expansion Factor	
Vapor Space Expansion Factor:	0.0372
Daily Vapor Temperature Range (deg. R):	21.7068
Daily Vapor Pressure Range (psia):	0.0029
Breather Vent Press. Setting Range (psia):	0.0600
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0086
Vapor Pressure at Daily Minimum Liquid Surface Temperature (psia):	0.0072
Vapor Pressure at Daily Maximum Liquid Surface Temperature (psia):	0.0101
Daily Avg. Liquid Surface Temp. (deg R):	527.9279
Daily Min. Liquid Surface Temp. (deg R):	522.5012
Daily Max. Liquid Surface Temp. (deg R):	533.3546
Daily Ambient Temp. Range (deg. R):	20.4833

Vented Vapor Saturation Factor	
Vented Vapor Saturation Factor:	0.9970
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0086
Vapor Space Outage (ft):	6.6731

Working Losses (lb):	866.8473
Vapor Molecular Weight (lb/lb-mole):	130.0000
Vapor Pressure at Daily Average Liquid	
Surface Temperature (psia):	0.0086
Annual Net Throughput (gal/yr.):	32,700,000.0000
Annual Turnovers:	14.0000
Turnover Factor:	1.0000
Maximum Liquid Volume (gal):	2,379,458.3146
Maximum Liquid Height (ft):	49.5000
Tank Diameter (ft):	90.0000
Working Loss Product Factor:	1.0000
 Total Losses (lb):	 979.9184

TANKS 4.0.9d
Emissions Report - Detail Format
Individual Tank Emission Totals

Emissions Report for: Annual

Effingham rev2 - Vertical Fixed Roof Tank
Rincon, Georgia

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Distillate fuel oil no. 2	866.85	113.07	979.92

APPENDIX B
MODELING PROTOCOL

March 9, 2010

103-87522

Via Electronic Delivery

Georgia Department of Natural Resources
ATTN: Mr. Peter Courtney
Environmental Protection Division, Air Protection Branch
4244 International Parkway, Suite 120
Atlanta, GA 30354

**RE: AIR MODELING PROTOCOL FOR ASSESSING POLLUTANT AND AQRV IMPACTS FOR A
PROPOSED EXPANSION OF THE EFFINGHAM COUNTY POWER PLANT**

Dear Mr. Courtney:

On behalf of Mackinaw Power, Golder Associates Inc. (Golder) is providing this air modeling protocol to the Georgia Department of Natural Resources (GDNR) to present the air modeling methodologies to be used for the proposed expansion of the Effingham County Power Plant (Facility). Mackinaw Power plans to expand the Facility by adding two General Electric (GE) 7FA combustion turbines (CTs) rated at approximately 200 megawatts (MW) each, two heat recovery steam generators (HRSGs) with duct firing, a steam turbine, and auxiliary equipment (the Project). The Facility, currently operating under Title V Operating Permit No. 4911-103-0012-V-03, has two existing GE 7FA model CTs nominally rated at 185 MW each, two HRSGs with no duct firing, and one steam turbine rated at 155 MW.

The Facility is located in Effingham County, Georgia, which is designated as attainment or unclassified for all criteria air pollutants. Under the New Source Review (NSR) rules, the Facility is currently a major source of air pollutants as specified by the Prevention of Significant Deterioration (PSD) regulations that apply for major sources located in attainment areas. As such, any emission increases of Clean Air Act (CAA) regulated air pollutants from the project that are greater than the U.S. Environmental Protection Agency's (EPA's) significant emission rate (SER) thresholds [40 Code of Federal Regulations (CFR) Part 52.21(b)(23)] will require PSD review for those pollutants. The proposed expansion project will have emissions of certain pollutants greater than the SER thresholds and would, therefore, be considered a "major modification" at a major source, subject to the PSD air permitting requirements.

This air modeling protocol presents the most current, accepted air modeling techniques and methodologies for predicting both near-field and far-field pollutant concentrations to ensure that the air modeling analyses required for the Project will be conducted in a manner that is consistent with GDNR and EPA requirements, as well as those of the Federal Land Managers (FLM) for affected PSD Class I areas.

The key features of the air modeling analyses are included in the following sections.

PROJECT DESCRIPTION AND LOCATION

As discussed previously, the Project involves the construction of two CTs, each generating up to approximately 200 MW of power; two HRSGs, each with duct burners, and one steam turbine, generating approximately 260 MW of power. Each duct burner will have a maximum heat input of 550 million British thermal units per hour (MMBtu/hr). The primary fuel for the CTs will be pipeline quality natural gas with up to 1,000 hours per year of ultra-low sulfur fuel oil used as the backup fuel in each CT. The duct burners will be fired only by pipeline quality natural gas. A cooling tower will be installed to provide cooling water to the condensing steam turbine. Additional equipment includes a fuel gas heater, an ammonia handling facility for the selective catalytic reduction (SCR) system, a fuel oil storage tank, and a gas metering station.

The Project will be located near Rincon in Effingham County which has been designated by the EPA and GDNR as an attainment or unclassified area for all criteria pollutants [i.e., sulfur dioxide (SO₂), nitrogen dioxide (NO₂), carbon monoxide (CO), particulate matter with aerodynamic diameter of 10 microns or less (PM₁₀), particulate matter with aerodynamic diameter of 2.5 microns or less (PM_{2.5}), ozone, and lead (Pb)]. Effingham County and surrounding counties are designated as PSD Class II areas. The east and north UTM coordinates for the Project location are approximately 473.30 kilometers (km) and 3571.49 km, respectively, in UTM Zone 17, North American Datum of 1983 (NAD83).

The Project's emissions will be reviewed following the NSR procedures for attainment areas under the PSD regulations for applicable pollutants, such as SO₂, nitrogen oxides (NO_x), CO, PM₁₀, PM_{2.5}, volatile organic compounds (VOC) (as a precursor to ozone), and Pb.

The maximum potential emissions for the Project are estimated and compared to the EPA SER, as listed in Table 1. These are preliminary estimates which represent the Project's maximum annual emissions at this time and will be better defined when the air construction permit application is submitted.

TABLE 1
PRELIMINARY ESTIMATE OF THE MAXIMUM POTENTIAL
ANNUAL EMISSIONS FOR THE PROJECT

Pollutant	Project Maximum Emissions (TPY)	Significant Emission Rate (TPY)
SO₂	100	40
NO_x	190	40
PM	100	25
PM₁₀	90	15
PM_{2.5}	90	10
CO	400	100
SAM	20	7
VOC	100	40

Each emission unit will be modeled at its maximum short-term emission rate to address compliance with the short-term ambient air quality standards (AAQS) and PSD increments. The annual emission rates, as shown in Table 1, may be used to address compliance with the annual AAQS and PSD increments; otherwise, the short-term emission rates will be used as appropriate.

As required under PSD regulations, a best available control technology (BACT) evaluation will be performed using the currently mandated "top-down" approach. The EPA BACT/RACT/LAER Clearinghouse will be reviewed to identify BACT technologies and emission limits for similar sources. Alternative control technologies will be identified and assessed as to their technical feasibility. For technically feasible alternatives, capital and operating costs will be determined, and control effectiveness in terms of dollars-per-ton-of-pollutant controlled will be developed.

The proposed emission controls for NO_x emissions for the CTs include the use of dry-low NO_x (DLN) combustors and SCR system. Low-NO_x burners and SCR are proposed as controls for the duct burners. The NO_x concentrations from these sources are proposed to be 2.5 parts per million by volume dry (ppmvd), corrected to 15-percent oxygen (O₂) including duct firing in the HRSG. The proposed emission rates for VOC, CO, PM, PM₁₀, and PM_{2.5} are based on good combustion practices utilizing the DLN combustor and firing pipeline quality natural gas fuel. The proposed emission rates for SO₂ and sulfuric acid mist (SAM) are based on the use of pipeline quality natural gas and ultra-low sulfur fuel oil.

Based on recent NSR regulations for PM_{2.5}, effective July 15, 2008, emissions of precursor pollutants are also used to evaluate pollutant applicability as well as emission controls. These precursor pollutants

include SO₂ and other pollutants that the state may determine contribute to PM_{2.5}. Other pollutants include NO_x, VOC, and ammonia.

The information presented in this modeling protocol includes the air modeling procedures and assumptions needed to address air quality impacts under the PSD regulations.

DISPERSION MODELING – PSD CLASS II AREAS

Model Selection and General Assumptions

The air modeling analysis for the PSD Class II areas (near-field modeling) will be performed using the American Meteorological Society (AMS)/EPA Regulatory Model (AERMOD, Version 09292) to predict concentrations in the vicinity of the Project site location. The near-field analysis is based on predicting impacts within 50 km from the Project. EPA's regulatory default options will be used to predict all maximum impacts. These options include:

- Elevated terrain algorithms
- Stack-tip downwash (except for building downwash cases)
- Missing data processing routines
- Calm wind processing routines
- 4-hour half life for exponential decay of SO₂ for urban sources

Project Modeled Emissions

The Project's CTs will be modeled when firing natural gas and fuel oil, for a range of operating loads (e.g., 50, 75, and 100 percent), and for ambient temperatures of 20, 59, and 95 degrees Fahrenheit (°F). Duct-firing will also be modeled when the CTs are firing natural gas with 100-percent operating load for ambient temperatures of 59 and 95°F.

The fuel gas heater will also be modeled with the CT emissions since the fuel heater can operate all year. PM emissions from the cooling tower will be included when modeling the project for PM impacts.

Startup and shutdown emissions will be included in the modeling analysis to assess the maximum pollutant concentrations as appropriate for each pollutant. It is expected that this will be performed for CO emissions since the emission rates for other pollutants are expected to be much lower during the normal operation of the CTs.

Building Downwash Considerations

The proposed stacks for the Project sources will be evaluated for determining compliance with Good Engineering Practice (GEP) regulations and the potential influence of nearby buildings and structures that could cause building downwash. For each stack that is below the GEP height, direction-specific building heights and maximum projected widths will be determined using the Building Profile Input Program (BPIP, Version 04274) which incorporates the Plume Rise Model Enhancement (PRIME) downwash algorithm developed by the Electric Power Research Institute (EPRI). The direction-specific building information output by BPIP will be input to the air dispersion model for processing.

Meteorological Data

The meteorological data to be used for the near-field analysis consists of a 5-year hourly record consisting of surface and upper air data from the National Weather Service (NWS) stations in Savannah, Georgia (SAV), and Charleston, South Carolina, respectively, for years 1990 to 1994. Recent communications with GDNDR has indicated that the SAV meteorological record would be considered suitable for sources located in Effingham County. The meteorological data have been processed by GDNDR using the AERMOD meteorological pre-processor program AERMET (Version 06340).

The SAV meteorological data record contains seasonal land use values of surface roughness, Bowen Ratio, and albedo that been developed by GDNR using procedures outlined in the most recent regulatory guidance presented in the AERMOD Implementation Guide (revised January 9, 2008). Output from EPA's AERSURFACE tool was used to provide seasonal land use parameter values for up to 12 wind direction sectors that were used for input to AERMET's Stage 3 processing.

To estimate the possible differences in land use features between SAV and the Project site that could affect predicted impacts, the SAV meteorological data for which the highest concentrations were predicted in the significant impact analysis (for critical averaging periods, such as the 24-hour period) will be reprocessed with AERMET using seasonal land use parameters calculated from the area surrounding the Project site. If the predicted impacts are greater with the land use parameters from the Project site, the remaining 4 years of SAV meteorological record will be processed with the Project site land use values and used for the remainder of the impact assessment.

Receptors

Receptors will be placed along the Project site's restricted property boundary (i.e., fenceline) and beyond the fenceline according to the following receptor spacing.

- Along the property boundary or fenceline – 50 meter (m) spacing
- Beyond the fenceline to 2 km – 100 m spacing
- From 2 km to 5 km – 250 m spacing
- From 5 km to 10 km – 500 m spacing.

Maximum predicted concentrations will be obtained from a receptor grid comprised of 50-m resolution on the fenceline and 100-m resolution beyond the fenceline. AERMOD's terrain preprocessing program, AERMAP (Version 09040), will be used to process the receptor grid data in all near-field areas, using seamless National Elevation Data (NED) of the greatest horizontal resolution from the U.S. Geological Survey website. These data will then be processed within the model domain based on NAD83.

For a detailed modeling analysis, if required, the receptor grid will extend from the fenceline to the distance of the Project's significant impact on a pollutant-specific basis.

Significant Impact Analysis

A significant impact analysis will be performed for the Project's emissions based on the CT emission scenarios for the range of operating loads and ambient temperatures (described previously), fuel heater, and cooling tower. If the highest predicted impact for a particular pollutant exceeds the PSD Class II significant impact levels (SIL), a more detailed modeling analysis will be performed for that pollutant. The critical load and temperature will then be used in the detailed analysis with other background facilities as discussed in the following sections.

Detailed Impact Modeling Analyses

If the highest predicted impact for a particular pollutant exceeds the SIL, pollutant-specific analyses will be performed to demonstrate compliance with AAQS and with the allowable PSD Class II Increments. The AAQS analysis will include the Project along with background facility emission data and a non-modeled background concentration for comparison to the AAQS. In the PSD Class II increment analysis, PSD increment consuming and expanding sources will be modeled for comparison to the allowable PSD Class II increments.

Background AAQS and PSD increment-affecting sources for those pollutants will be requested from GDNR. In addition, emissions and stack parameters for facilities will be developed from information contained in previous air modeling reports or from other data sources (e.g., Title V permit applications).

Background sources located within the significant impact area (SIA), the modeling area, will be included in the modeling. Background sources located 50 km beyond the modeling areas, referred to as the screening area, will also be considered.

To reduce the number of background sources to be evaluated in the screening area, the "Screening Threshold" method developed by the North Carolina Department of Natural Resources and Community Development will be used. Based on this technique, facilities whose annual emissions [i.e., ton per year] (TPY) are less than the threshold quantity, Q , are eliminated from the modeling analysis. Q is equal to $20 \times (D-SIA)$, where D is the distance in km from the facility to the Project site, and SIA is the distance of the Project's pollutant-specific SIA. The facilities that are not eliminated in the screening analysis will be included in the AAQS and PSD Class II analyses.

Facilities with large emission rates, such as greater than 1,000 TPY, which are located beyond the screening area and up to 100 km will also be included in the analysis. In addition, total emissions from the facilities that are located very close to one another will be compared using the North Carolina method to include the emissions from the closely located facilities in the modeling analysis.

NO₂ 1-Hour Standard

On January 22, 2010, EPA finalized a new 1-hour average standard at a level of 100 parts per billion (ppb), based on the 3-year average of the 98th percentile of the yearly distribution of 1-hour daily maximum concentrations, to supplement the existing annual standard. Although a modeling demonstration is not required until the area designations and implementation plan with SILs and PSD increment levels are finalized, GDNr has requested that the Project's impacts be provided.

At present, there are no SIL or PSD increments that have been proposed. Since only the AAQS has been promulgated, total air quality impacts will be estimated with the Project's impacts plus background, which will be obtained from existing ambient air quality monitoring data available through GDNr, to determine compliance with AAQS. Please note that the uncertainty of this approach is that in absence of a SIL, any finite impact, however small it may be, could potentially be viewed as significant and could lead to a cumulative source impact modeling within a 100-km radius area around the project. Such a modeling analysis has the following drawbacks:

- Unnecessary rigorous modeling effort to include all NO_x-emitting sources within a 100-km radius. It is noted that this might occur even if maximum project impact is on the fenceline.
- Unintended consequence of the proposed source contributing to a receptor, which may be 50-km away from the proposed source, but shows violation of the NAAQS due to other existing sources. If no SIL exists, there is no practical way to assess the proposed project's contribution.

A SIL, therefore, is absolutely necessary for a meaningful modeling analysis focused on protecting the environment. As a result, Golder is proposing a 1-hour SIL of 7.5 micrograms per cubic meter ($\mu\text{g}/\text{m}^3$) for example, which is equivalent to 4 percent of the AAQS of 188 $\mu\text{g}/\text{m}^3$. The 4-percent level has been used by EPA to set significant impact levels in other cases.

Golder will use the current default NO₂ to NO_x ratio of 0.75 to predict the 1-hour average NO₂ impacts from the modeled NO_x impacts. Alternatively, the ozone limiting method (OLM) or the plume volume molar ratio method (PVMRM) could be used to predict the NO₂ impacts. Compliance with the SIL will be based on the highest predicted 1-hour NO₂ concentration using a 5-year meteorological record.

If the 1-hour SIL is exceeded, GDNr will be contacted to provide a list of background NO₂ sources. The significant impact distance of the project will be determined and will represent the maximum receptor distance for the modeling area of a cumulative impact assessment.

PM_{2.5} Standard

A SIL for PM_{2.5} is yet to be finalized. EPA proposed the following SILs for PM_{2.5} in a Class II area on September 21, 2007 (Federal Register 54111, September 21, 2007):

- Option 1: Annual – 1.0 µg/m³, 24-Hour – 5.0 µg/m³
- Option 2: Annual – 0.8 µg/m³, 24-Hour – 4.0 µg/m³
- Option 3: Annual – 0.3 µg/m³, 24-Hour – 1.2 µg/m³

Based on discussion with GDNR, Golder will predict annual and 24-hour average impacts of direct PM_{2.5} emissions only and compare them to the most stringent proposed annual and 24-hour average PM_{2.5} SILs of 0.3 and 1.2 µg/m³, respectively. If the maximum predicted PM_{2.5} impacts are greater than the SIL, Golder will communicate with GDNR staff to ensure that compliance with the annual average and 24-hour average PM_{2.5} AAQS are addressed in a manner that is consistent with the most recent air modeling guidance for PM_{2.5} approved by GDNR and EPA.

Toxic Air Pollutants

Air quality impacts for toxic air pollutants emitted by the Facility will be assessed by following the GDNR procedures in the *Guideline for Ambient Impact Assessment of Toxic Air Pollutant Emissions* (Toxics Guidelines) (GDNR, 1998). Per those guidelines, the Industrial Source Complex Short-Term (ISCST3) model is identified as the recommended model. Golder will discuss with GDNR the use of AERMOD to provide maximum concentrations for the appropriate averaging times for each pollutant. These concentrations will then be compared to the latest acceptable ambient concentrations (AACs), which will be developed following the procedure in the Toxics Guidelines.

DISPERSION MODELING – PSD CLASS I AREAS

Model Selection and General Assumptions

The CALPUFF air modeling system (Version 5.8) will be used to predict the Project's maximum air quality concentrations at locations beyond 50 km from the Project. CALPUFF is a non-steady state Lagrangian puff long-range transport model that includes algorithms for chemical transformations (important for visibility controlling pollutants) and wet/dry deposition. CALPUFF will be used in a manner that is consistent with methodologies recommended in the following documents and previous discussions with the FLM.

- FLMs' AQRV Workgroup (FLAG) guidance document, finalized in December 2000 and referred to as the FLAG Phase I Report
- Interagency Workgroup on Air Quality Models (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long-Range Transport Impacts (EPA, 1998), referred to as the IWAQM Phase 2 report.

Parameter settings to be used in CALPUFF will be based on the latest regulatory guidance. Where the modeling guidance recommends regulatory model defaults, those defaults will be used. For ozone background concentrations, observed hourly ozone data for 2001 to 2003 from CASTNET and AIRS stations will be used. These data are available from the TRC website. A fixed monthly ammonia background concentration of 0.5 ppb will be used. Parameters will be set to generate an hourly relative humidity file for calculating 24-hour visibility impairment using CALPOST visibility method number 2. In addition, parameters will be set to calculate wet and dry (i.e., total) fluxes and concentrations at each PSD Class I area.

Project Modeled Emissions

The Project's emission, stack, and operating data as well as building dimensions will be modeled for the emission sources as indicated previously. This will include the CTs and fuel gas heater operating under normal operations. The CT emissions and stack parameters used for the far-field analysis will be from the load and ambient temperature that produces the highest CT emission rate. This will likely occur during base load and ambient temperature of 20°F. Because of the distances between the Project and PSD Class I areas and low-level release heights from the cooling tower, the PM emissions from the cooling tower will not be modeled.

PM emissions for the Project's CTs will be speciated into filterable and condensable components and into six particle size categories. The effect that each species has on visibility impairment is related to a parameter called the extinction coefficient. The higher the extinction coefficient, the greater is that species' effect on visibility. Filterable PM is speciated into coarse (PMC), fine (PMF), and elemental carbon (EC). The default extinction efficiencies for these species are 0.6, 1.0, and 10.0, respectively. PMC is PM with aerodynamic diameters greater than 2.5 microns. Both EC and PMF have aerodynamic diameters equal to or less than 2.5 microns. Condensable PM is comprised of sulfate (SO₄) and secondary organic aerosols (SOA). The extinction efficiencies for these species are $3 \times f(RH)$ and 4, respectively, where $f(RH)$ is the relative humidity factor.

The PM group will then be speciated into filterable and condensable species using the POSTUTIL utility program. Note that emissions for condensable inorganic PM are input directly to CALPUFF as SO₄.

PM speciation (PM₁₀ versus PM_{2.5}) will be developed based on the best available vendor information for the project's emission sources.

Building Downwash Considerations

The same methods used in the PSD Class II analyses to assess building downwash will be used in these analyses.

Meteorological Data

The far-field air modeling analyses will be conducted using the latest meteorological and geophysical databases which have been developed for use with the most recent versions of CALPUFF. These datasets were developed using CALMET Version 5.8 and were originally developed by VISTAS and recompiled for Version 5.8 by the FLM. The domain has 4-km spacing and covers the period from 2001 to 2003.

Receptors

The following PSD Class I areas are the only Class I areas located within 300 km of the Project site:

- Wolf Island National Wilderness Area (WNWA) - 101 km
- Okefenokee NWA (ONWA) - 162 km
- Cape Romain NWA (CRNWA) 167 km

The FLM has developed receptors to represent the boundary and internal areas of all PSD Class I areas. The analysis will use the receptors developed by the FLM for these Class I areas.

Significant Impact Analysis

Significant impact analyses will be performed to assess the Project's impacts at the PSD Class I areas. The maximum predicted SO₂, NO₂, and PM₁₀ concentrations due to the Project will be compared to EPA's proposed PSD Class I significant impact levels. If the Project's impacts exceed the proposed EPA PSD Class I significant impact levels, then a more detailed PSD Class I increment analysis will be performed

on a pollutant-specific basis. In the PSD Class I incremental analysis, PSD-increment affecting sources will be modeled for comparison to the allowable PSD Class I increments. The proposed PSD Class I significant impact levels are:

- SO₂: 3-hour – 1.0 µg/m³, 24-hour – 0.2 µg/m³, and annual average – 0.1 µg/m³
- NO₂: annual average – 0.1 µg/m³
- PM₁₀: 24-hour – 0.3 µg/m³, and annual average – 0.2 µg/m³

If a detailed PSD Class I impact assessment is required for one or more pollutants, an inventory of background PSD Class I increment-affecting sources will be developed with the assistance from GDNR.

AQRV Analyses

Q/D Approach

A revised FLAG document was published as a draft in June 2008, which has initial screening criteria that would exempt a source from AQRV impact review based on its annual emissions and distance from a Class I area. According to the revised FLAG document, a source located more than 50 km from a Class I area will have negligible impacts with respect to Class I AQRVs if its total SO₂, NO_x, PM₁₀, and SAM annual emissions (Q, in TPY, based on 24-hour maximum allowable emissions), divided by the distance from the Class I area (D, in km), Q/D, is 10 or less. Based on preliminary information provided using the Project's maximum annual emissions, the results of the Q/D analysis are presented in Table 2.

TABLE 2
PRELIMINARY SCREENING CRITERIA TO EXEMPT EMISSION SOURCE
FROM AQRV IMPACT REVIEW ¹

PSD Class I Area	Project Distance (D) (km) from PSD Class I Area	Q/D ²
Wolf Island NWA	101	2.5
Okefenokee NWA	162	1.5
Cape Romain NWA	167	1.5

¹ Draft FLMs' AQRV Workgroup (FLAG) Phase I Report- Revised (June 2008): If Q/D <10, then AQRV analysis may not be required.

² Q = 250.6 TPY (SO₂ = 100 TPY; NO_x = 40 TPY; PM₁₀ = 90 TPY; SAM = 20 TPY).

As shown in Table 2, the Q/D ratios for each of the PSD Class I areas within 300 km of the Project are less than 10. Therefore, in accordance with the 2008 draft FLAG guidance, the Project could be considered as not causing or contributing to impacts on AQRVs. Consequently, Mackinaw Power proposes that additional Class I AQRV analyses would not be required if the Project emissions meet the Q/D criterion and concurrence of the FLM is obtained.

The following Class I area methodology discussions are included to address the evaluation of AQRV impacts if this evaluation is deemed necessary.

Visibility

The project's impact on 24-hour visibility impairment in the form of regional haze will be compared with the FLM suggested visibility impairment criteria of 5 percent of the average background visual range of the top 5-percent visibility days.

Based on the FLAG document, current regional haze guidelines characterize a change in visibility by the change in the light-extinction coefficient (b_{ext}). The b_{ext} is the attenuation of light per unit distance due to the scattering and absorption by gases and particles in the atmosphere. A change in the extinction coefficient produces a perceived visual change. An index that simply quantifies the percent change in visibility due to the operation of a source is calculated as:

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

where: b_{exts} is the extinction coefficient calculated for the source

b_{extb} is the background extinction coefficient

The purpose of the visibility analysis is to calculate the extinction at each receptor for each day (24-hour period) of the year due to the project emissions.

The visibility analysis will be conducted for the applicable Class I areas using CALPUFF. The CALPUFF postprocessor model CALPOST will be used to calculate the combined visibility effects from the different pollutants that are emitted from the Project. Based on communications with the NPS, daily background extinction coefficients are to be calculated on an hour-by-hour basis using hourly RH data from CALMET and hygroscopic and non-hygroscopic extinction components specified in the FLAG document (Visibility Method 2). For each PSD Class I area in the region, the hygroscopic and non-hygroscopic components are 0.9 and 8.5 inverse megameters (Mm^{-1}), respectively. CALPOST calculates the percent extinction change for each day of the year. The default Rayleigh scattering term of $10 Mm^{-1}$ will be used for the analysis. The revised RH scattering enhancement factor $[f(RH)]$ growth curve published by EPA in 2003 will be used in the analysis.

Additional Visibility Assessment

The draft revised FLAG document recommends Visibility Method 8 as the method used to determine background light extinction, which differs from Visibility Method 2 by the use of monthly RH adjustment instead of hourly. Golder will also perform the visibility impairment analysis using Visibility Method 8 and follow the revised FLAG procedures. According to the revised procedure, the visibility threshold for concern is not exceeded if the 98th-percentile change in light extinction is less than 5 percent for each year modeled, when compared to the annual average natural condition value for the Class I area.

Sulfur and Nitrogen Deposition

Sulfur (S) and nitrogen (N) deposition for the Project will be calculated with CALPUFF at the PSD Class I areas. The deposition analysis criterion is based on the annual averaging period. The total deposition is estimated in units of kilogram per hectare per year (kg/ha/yr) of nitrogen or sulfur. CALPUFF is used to predict wet and dry deposition fluxes of various oxides of these elements.

For N deposition, the species include:

- Particulate ammonium nitrate (from species NO_3), wet and dry deposition
- Nitric acid (species nitric acid $[HNO_3]$), wet and dry deposition
- NO_x dry deposition
- Ammonium sulfate (species SO_4), wet and dry deposition

For S deposition, the species include:

- SO_2 , wet and dry deposition
- SO_4 , wet and dry deposition

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

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

The wet and dry sulfate and nitrate fluxes will be converted into total N and S fluxes using the POSTUTIL utility program.

PRECONSTRUCTION AMBIENT MONITORING ANALYSIS

In addition to comparison to the SILs, the Project's maximum pollutant impacts will also be compared to the *de minimis* air monitoring concentration to address preconstruction ambient air monitoring requirements under the PSD regulations. Should the Project's maximum pollutant impacts exceed a *de minimis* monitoring concentration, a request will be made that existing representative ambient air monitoring data be used to satisfy this requirement.

ADDITIONAL IMPACT ANALYSIS

The additional impact analyses required under PSD review include an analysis of the impacts of Project emissions on soils, vegetation, and visibility. The analysis of impacts due to associated growth in the area must also be addressed. To address such impacts, soil and vegetation types in the vicinity of the plant must be identified. A literature review will be conducted to identify the most recent data concerning threshold effect levels for the soil and vegetation types in the area. An assessment of air emissions impacts upon these values will then be prepared. Growth effects will be addressed qualitatively, including impacts due to secondary emissions from the facility.

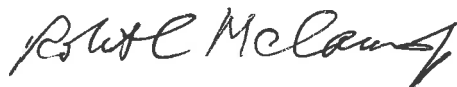
The analyses will conform to procedures recommended by the EPA, such as those in the document *A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils and Animals* (EPA 1980), and other appropriate literature.

CONCLUDING REMARKS

We look forward to receiving your comments on this protocol and working with the GDNR on this important project. If there are any questions, please contact me or Steve Marks at (352) 336-5600.

Sincerely,

GOLDER ASSOCIATES INC.



Robert C. McCann, Jr.
Principal



Steven R. Marks, C.C.M.
Associate

cc: Matthew Lydon, Mackinaw Power
Sal Mohammad, GAI Gainesville
Steven Moeller, GAI Atlanta
Jill Webster, U.S. Fish and Wildlife Service

RCM/SRM/edk

APPENDIX C
CORRESPONDENCE

May 6, 2010

103-87522

Via Electronic Delivery

Mr. Stan Krivo
U.S. Environmental Protection Agency
Region 4
Sam Nunn Atlanta Federal Center
61 Forsyth Street, SW
Atlanta, GA 30303-8960

**RE: REQUEST TO USE THE PLUME VOLUME MOLAR RATIO METHOD (PVMRM) TO ESTIMATE
AMBIENT NO₂ CONCENTRATIONS
MACKINAW POWER
EXPANSION OF EFFINGHAM POWER PLANT, GEORGIA**

Dear Mr. Krivo:

Golder Associates Inc. (Golder) has been retained by Mackinaw Power to prepare a Prevention of Significant Deterioration (PSD) air construction permit application for the proposed 600-megawatt (MW) expansion project with combined cycle technology at the existing Effingham Power Plant in Effingham County, Georgia. Golder submitted an air dispersion modeling protocol to the Environmental Protection Division (EPD) of the Georgia Department of Natural Resources (DNR) on March 9, 2010, which is provided in Attachment A.

In this letter, Golder requests approval to use the Plume Volume Molar Ratio Method (PVMRM) option of AERMOD for the determination of nitrogen dioxide (NO₂) concentrations as part of the air quality analysis for the project.

As you know, the new 1-hour average NO₂ ambient air quality standard (AAQS) of 188 micrograms per cubic meter (µg/m³) was finalized on February 9, 2010. Demonstrations showing AAQS compliance are required for a project that undergoes PSD review if the project does not have a complete permit by April 12, 2010. Previously, air quality impact assessments for PSD application needed to only address the annual average NO₂ AAQS, which typically did not require a more detailed screening approach such as the use of PVMRM.

Golder's request to use PVMRM for predicting the NO₂ concentrations is based on the following reasons:

- EPA's Guideline on Air Quality Models (GAQM) (Appendix W, 40 CFR 51, July 2009) recommends the use of a multi-tiered approach to estimate NO₂ concentration
- PVMRM is already implemented in AERMOD, which is approved by EPA for assessing impacts within 50 kilometers (km) of a source
- Based on studies and the science, the PVMRM chemistry appears to be more realistic in treating the conversion of nitric oxide (NO) to NO₂ and limiting the conversion as it considers the situation within the plume itself
- PVMRM has been approved for use by EPA in the State of Alaska and is used in the air modeling community outside of the U.S.

As indicated, GAQM recommends a multi-tiered screening approach for estimating annual NO₂ concentrations, where:

- Tier 1 assumes full conversion of nitrogen oxides (NO_x) to NO₂
- Tier 2 assumes a 75-percent ambient equilibrium ratio of NO₂ to NO_x
- Tier 3 allows detailed screening techniques on a case-by-case basis

In general, maximum NO₂ concentrations estimated using Tier 1 (total conversion) or Tier 2 (default equilibrium NO₂/NO_x ratio of 0.75) provide conservative estimates of NO₂ concentrations when assessing compliance with the annual standard of 100 µg/m³. For stationary sources with NO_x emission controls, such as the current project, the NO₂ impacts are predicted to be well below the annual AAQS and, in many cases, less than the annual significant impact level. However, for the 1-hour average concentrations, which are greatly affected by the widely varying meteorological conditions, modeling of the emission sources, such as those for this project, can show 1-hour average NO₂ concentrations to be high relative to the 1-hour AAQS of 188 µg/m³ using the Tier 1 or the Tier 2 approach. There is a clear need to perform a more detailed screening analysis, using less conservative assumptions and more realistic methods, to account for NO₂ formation when assessing NO₂ concentrations from a source, such as the PVMRM method that Golder proposes.

PVMRM is discussed in Section 5.1, Appendix W, and was being tested to determine its suitability as a refined method when the GAQM was last updated in 2005. Since that time, the PVMRM algorithm has been implemented into AERMOD and is currently available in the most recent version of the model (Version 09292) as a “non-default” option. The addendum to the AERMOD User’s Guide dated October 2009 provides the usage instructions for PVMRM.

Two detailed methods for assessing NO₂ concentrations are PVMRM and Ozone Limiting Method (OLM), also discussed in the GAQM. Both PVMRM and OLM are ambient ozone-based algorithms that limit the conversion of NO to NO₂ based on available ambient ozone. The PVMRM uses the same chemistry and ozone concentration data as OLM but also accounts for plume size to derive the amount of ozone available within the plume for the reaction between NO and ozone. In contrast, the OLM does not account for the plume size or in-plume concentrations. For a given NO_x emission rate and ambient ozone concentration, PVMRM controls the conversion of NO to NO₂ based on NO_x within the volume of the plume in contrast to OLM, which controls the conversion based on ground-level NO_x.

Because of the reasons above and additional support material, EPA Region 10 approved the use of the PVMRM option in 2006 for ambient air quality analyses prepared for the State of Alaska (see EPA letter dated January 13, 2006 provided in Attachment B). The additional support material provided to the Alaska Department of Environmental Conservation (ADEC) included a sensitivity analysis using OLM and PVMRM options in AERMOD performed in September 2004, and an evaluation of bias using PVMRM option in AERMOD performed in June 2005. Both of these studies helped EPA Region 10 to determine that the non-default PVMRM option in AERMOD is an acceptable technique to predict NO₂ concentration impacts from combustion sources emitting NO_x through a stack and results in unbiased concentration impacts. As a result of this determination, EPA Region 10 approved the PVMRM option for application in Alaska. The PVMRM method was most recently used for the Exxon Mobil Corporation’s Point Thomson Drilling Operations air permit application (ADEC Technical Analysis Report for Permit AQ1201MSS01, April 2010).

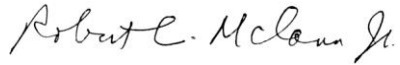
The PVMRM method is also the recommended method to be used for predicting NO₂ concentrations elsewhere, such as in Alberta, Canada (Air Quality Modeling Guidelines, Government of Alberta).

Golder proposes to use an initial NO₂ concentration equivalent to 10 percent of NO_x at the stack and an equilibrium NO₂ to NO_x ratio of 0.9 in the plume, which are the current default values per the AERMOD User’s Guide. Golder will obtain hourly ozone monitoring data available from the area monitors for the period of the modeling meteorological data and coordinate with the Georgia EPD for representativeness of the data.

Thank you for consideration of this information. If you have any questions, please do not hesitate to call us at (352) 336-5600 or via email (bmccann@golder.com and smohammad@golder.com).

Sincerely,

GOLDER ASSOCIATES INC.



Robert C. McCann, Jr.
Principal and Group Leader



Salahuddin Mohammad
Senior Project Engineer

cc: Pete Courtney, GEPD
Matthew Lydon, Mackinaw Power
Steven Marks, Golder

Enclosures

SKM/tz

ATTACHMENT A
AIR DISPERSION MODELING PROTOCOL

March 9, 2010

103-87522

Via Electronic Delivery

Georgia Department of Natural Resources
ATTN: Mr. Peter Courtney
Environmental Protection Division, Air Protection Branch
4244 International Parkway, Suite 120
Atlanta, GA 30354

**RE: AIR MODELING PROTOCOL FOR ASSESSING POLLUTANT AND AQRV IMPACTS FOR A
PROPOSED EXPANSION OF THE EFFINGHAM COUNTY POWER PLANT**

Dear Mr. Courtney:

On behalf of Mackinaw Power, Golder Associates Inc. (Golder) is providing this air modeling protocol to the Georgia Department of Natural Resources (GDNR) to present the air modeling methodologies to be used for the proposed expansion of the Effingham County Power Plant (Facility). Mackinaw Power plans to expand the Facility by adding two General Electric (GE) 7FA combustion turbines (CTs) rated at approximately 200 megawatts (MW) each, two heat recovery steam generators (HRSGs) with duct firing, a steam turbine, and auxiliary equipment (the Project). The Facility, currently operating under Title V Operating Permit No. 4911-103-0012-V-03, has two existing GE 7FA model CTs nominally rated at 185 MW each, two HRSGs with no duct firing, and one steam turbine rated at 155 MW.

The Facility is located in Effingham County, Georgia, which is designated as attainment or unclassified for all criteria air pollutants. Under the New Source Review (NSR) rules, the Facility is currently a major source of air pollutants as specified by the Prevention of Significant Deterioration (PSD) regulations that apply for major sources located in attainment areas. As such, any emission increases of Clean Air Act (CAA) regulated air pollutants from the project that are greater than the U.S. Environmental Protection Agency's (EPA's) significant emission rate (SER) thresholds [40 Code of Federal Regulations (CFR) Part 52.21(b)(23)] will require PSD review for those pollutants. The proposed expansion project will have emissions of certain pollutants greater than the SER thresholds and would, therefore, be considered a "major modification" at a major source, subject to the PSD air permitting requirements.

This air modeling protocol presents the most current, accepted air modeling techniques and methodologies for predicting both near-field and far-field pollutant concentrations to ensure that the air modeling analyses required for the Project will be conducted in a manner that is consistent with GDNR and EPA requirements, as well as those of the Federal Land Managers (FLM) for affected PSD Class I areas.

The key features of the air modeling analyses are included in the following sections.

PROJECT DESCRIPTION AND LOCATION

As discussed previously, the Project involves the construction of two CTs, each generating up to approximately 200 MW of power; two HRSGs, each with duct burners, and one steam turbine, generating approximately 260 MW of power. Each duct burner will have a maximum heat input of 550 million British thermal units per hour (MMBtu/hr). The primary fuel for the CTs will be pipeline quality natural gas with up to 1,000 hours per year of ultra-low sulfur fuel oil used as the backup fuel in each CT. The duct burners will be fired only by pipeline quality natural gas. A cooling tower will be installed to provide cooling water to the condensing steam turbine. Additional equipment includes a fuel gas heater, an ammonia handling facility for the selective catalytic reduction (SCR) system, a fuel oil storage tank, and a gas metering station.

The Project will be located near Rincon in Effingham County which has been designated by the EPA and GDNR as an attainment or unclassified area for all criteria pollutants [i.e., sulfur dioxide (SO₂), nitrogen dioxide (NO₂), carbon monoxide (CO), particulate matter with aerodynamic diameter of 10 microns or less (PM₁₀), particulate matter with aerodynamic diameter of 2.5 microns or less (PM_{2.5}), ozone, and lead (Pb)]. Effingham County and surrounding counties are designated as PSD Class II areas. The east and north UTM coordinates for the Project location are approximately 473.30 kilometers (km) and 3571.49 km, respectively, in UTM Zone 17, North American Datum of 1983 (NAD83).

The Project's emissions will be reviewed following the NSR procedures for attainment areas under the PSD regulations for applicable pollutants, such as SO₂, nitrogen oxides (NO_x), CO, PM₁₀, PM_{2.5}, volatile organic compounds (VOC) (as a precursor to ozone), and Pb.

The maximum potential emissions for the Project are estimated and compared to the EPA SER, as listed in Table 1. These are preliminary estimates which represent the Project's maximum annual emissions at this time and will be better defined when the air construction permit application is submitted.

TABLE 1
PRELIMINARY ESTIMATE OF THE MAXIMUM POTENTIAL
ANNUAL EMISSIONS FOR THE PROJECT

Pollutant	Project Maximum Emissions (TPY)	Significant Emission Rate (TPY)
SO₂	100	40
NO_x	190	40
PM	100	25
PM₁₀	90	15
PM_{2.5}	90	10
CO	400	100
SAM	20	7
VOC	100	40

Each emission unit will be modeled at its maximum short-term emission rate to address compliance with the short-term ambient air quality standards (AAQS) and PSD increments. The annual emission rates, as shown in Table 1, may be used to address compliance with the annual AAQS and PSD increments; otherwise, the short-term emission rates will be used as appropriate.

As required under PSD regulations, a best available control technology (BACT) evaluation will be performed using the currently mandated "top-down" approach. The EPA BACT/RACT/LAER Clearinghouse will be reviewed to identify BACT technologies and emission limits for similar sources. Alternative control technologies will be identified and assessed as to their technical feasibility. For technically feasible alternatives, capital and operating costs will be determined, and control effectiveness in terms of dollars-per-ton-of-pollutant controlled will be developed.

The proposed emission controls for NO_x emissions for the CTs include the use of dry-low NO_x (DLN) combustors and SCR system. Low-NO_x burners and SCR are proposed as controls for the duct burners. The NO_x concentrations from these sources are proposed to be 2.5 parts per million by volume dry (ppmvd), corrected to 15-percent oxygen (O₂) including duct firing in the HRSG. The proposed emission rates for VOC, CO, PM, PM₁₀, and PM_{2.5} are based on good combustion practices utilizing the DLN combustor and firing pipeline quality natural gas fuel. The proposed emission rates for SO₂ and sulfuric acid mist (SAM) are based on the use of pipeline quality natural gas and ultra-low sulfur fuel oil.

Based on recent NSR regulations for PM_{2.5}, effective July 15, 2008, emissions of precursor pollutants are also used to evaluate pollutant applicability as well as emission controls. These precursor pollutants

include SO₂ and other pollutants that the state may determine contribute to PM_{2.5}. Other pollutants include NO_x, VOC, and ammonia.

The information presented in this modeling protocol includes the air modeling procedures and assumptions needed to address air quality impacts under the PSD regulations.

DISPERSION MODELING – PSD CLASS II AREAS

Model Selection and General Assumptions

The air modeling analysis for the PSD Class II areas (near-field modeling) will be performed using the American Meteorological Society (AMS)/EPA Regulatory Model (AERMOD, Version 09292) to predict concentrations in the vicinity of the Project site location. The near-field analysis is based on predicting impacts within 50 km from the Project. EPA's regulatory default options will be used to predict all maximum impacts. These options include:

- Elevated terrain algorithms
- Stack-tip downwash (except for building downwash cases)
- Missing data processing routines
- Calm wind processing routines
- 4-hour half life for exponential decay of SO₂ for urban sources

Project Modeled Emissions

The Project's CTs will be modeled when firing natural gas and fuel oil, for a range of operating loads (e.g., 50, 75, and 100 percent), and for ambient temperatures of 20, 59, and 95 degrees Fahrenheit (°F). Duct-firing will also be modeled when the CTs are firing natural gas with 100-percent operating load for ambient temperatures of 59 and 95°F.

The fuel gas heater will also be modeled with the CT emissions since the fuel heater can operate all year. PM emissions from the cooling tower will be included when modeling the project for PM impacts.

Startup and shutdown emissions will be included in the modeling analysis to assess the maximum pollutant concentrations as appropriate for each pollutant. It is expected that this will be performed for CO emissions since the emission rates for other pollutants are expected to be much lower during the normal operation of the CTs.

Building Downwash Considerations

The proposed stacks for the Project sources will be evaluated for determining compliance with Good Engineering Practice (GEP) regulations and the potential influence of nearby buildings and structures that could cause building downwash. For each stack that is below the GEP height, direction-specific building heights and maximum projected widths will be determined using the Building Profile Input Program (BPIP, Version 04274) which incorporates the Plume Rise Model Enhancement (PRIME) downwash algorithm developed by the Electric Power Research Institute (EPRI). The direction-specific building information output by BPIP will be input to the air dispersion model for processing.

Meteorological Data

The meteorological data to be used for the near-field analysis consists of a 5-year hourly record consisting of surface and upper air data from the National Weather Service (NWS) stations in Savannah, Georgia (SAV), and Charleston, South Carolina, respectively, for years 1990 to 1994. Recent communications with GDNDR has indicated that the SAV meteorological record would be considered suitable for sources located in Effingham County. The meteorological data have been processed by GDNDR using the AERMOD meteorological pre-processor program AERMET (Version 06340).

The SAV meteorological data record contains seasonal land use values of surface roughness, Bowen Ratio, and albedo that been developed by GDNR using procedures outlined in the most recent regulatory guidance presented in the AERMOD Implementation Guide (revised January 9, 2008). Output from EPA's AERSURFACE tool was used to provide seasonal land use parameter values for up to 12 wind direction sectors that were used for input to AERMET's Stage 3 processing.

To estimate the possible differences in land use features between SAV and the Project site that could affect predicted impacts, the SAV meteorological data for which the highest concentrations were predicted in the significant impact analysis (for critical averaging periods, such as the 24-hour period) will be reprocessed with AERMET using seasonal land use parameters calculated from the area surrounding the Project site. If the predicted impacts are greater with the land use parameters from the Project site, the remaining 4 years of SAV meteorological record will be processed with the Project site land use values and used for the remainder of the impact assessment.

Receptors

Receptors will be placed along the Project site's restricted property boundary (i.e., fenceline) and beyond the fenceline according to the following receptor spacing.

- Along the property boundary or fenceline – 50 meter (m) spacing
- Beyond the fenceline to 2 km – 100 m spacing
- From 2 km to 5 km – 250 m spacing
- From 5 km to 10 km – 500 m spacing.

Maximum predicted concentrations will be obtained from a receptor grid comprised of 50-m resolution on the fenceline and 100-m resolution beyond the fenceline. AERMOD's terrain preprocessing program, AERMAP (Version 09040), will be used to process the receptor grid data in all near-field areas, using seamless National Elevation Data (NED) of the greatest horizontal resolution from the U.S. Geological Survey website. These data will then be processed within the model domain based on NAD83.

For a detailed modeling analysis, if required, the receptor grid will extend from the fenceline to the distance of the Project's significant impact on a pollutant-specific basis.

Significant Impact Analysis

A significant impact analysis will be performed for the Project's emissions based on the CT emission scenarios for the range of operating loads and ambient temperatures (described previously), fuel heater, and cooling tower. If the highest predicted impact for a particular pollutant exceeds the PSD Class II significant impact levels (SIL), a more detailed modeling analysis will be performed for that pollutant. The critical load and temperature will then be used in the detailed analysis with other background facilities as discussed in the following sections.

Detailed Impact Modeling Analyses

If the highest predicted impact for a particular pollutant exceeds the SIL, pollutant-specific analyses will be performed to demonstrate compliance with AAQS and with the allowable PSD Class II Increments. The AAQS analysis will include the Project along with background facility emission data and a non-modeled background concentration for comparison to the AAQS. In the PSD Class II increment analysis, PSD increment consuming and expanding sources will be modeled for comparison to the allowable PSD Class II increments.

Background AAQS and PSD increment-affecting sources for those pollutants will be requested from GDNR. In addition, emissions and stack parameters for facilities will be developed from information contained in previous air modeling reports or from other data sources (e.g., Title V permit applications).

Background sources located within the significant impact area (SIA), the modeling area, will be included in the modeling. Background sources located 50 km beyond the modeling areas, referred to as the screening area, will also be considered.

To reduce the number of background sources to be evaluated in the screening area, the "Screening Threshold" method developed by the North Carolina Department of Natural Resources and Community Development will be used. Based on this technique, facilities whose annual emissions [i.e., ton per year] (TPY) are less than the threshold quantity, Q , are eliminated from the modeling analysis. Q is equal to $20 \times (D-SIA)$, where D is the distance in km from the facility to the Project site, and SIA is the distance of the Project's pollutant-specific SIA. The facilities that are not eliminated in the screening analysis will be included in the AAQS and PSD Class II analyses.

Facilities with large emission rates, such as greater than 1,000 TPY, which are located beyond the screening area and up to 100 km will also be included in the analysis. In addition, total emissions from the facilities that are located very close to one another will be compared using the North Carolina method to include the emissions from the closely located facilities in the modeling analysis.

NO₂ 1-Hour Standard

On January 22, 2010, EPA finalized a new 1-hour average standard at a level of 100 parts per billion (ppb), based on the 3-year average of the 98th percentile of the yearly distribution of 1-hour daily maximum concentrations, to supplement the existing annual standard. Although a modeling demonstration is not required until the area designations and implementation plan with SILs and PSD increment levels are finalized, GDNr has requested that the Project's impacts be provided.

At present, there are no SIL or PSD increments that have been proposed. Since only the AAQS has been promulgated, total air quality impacts will be estimated with the Project's impacts plus background, which will be obtained from existing ambient air quality monitoring data available through GDNr, to determine compliance with AAQS. Please note that the uncertainty of this approach is that in absence of a SIL, any finite impact, however small it may be, could potentially be viewed as significant and could lead to a cumulative source impact modeling within a 100-km radius area around the project. Such a modeling analysis has the following drawbacks:

- Unnecessary rigorous modeling effort to include all NO_x-emitting sources within a 100-km radius. It is noted that this might occur even if maximum project impact is on the fenceline.
- Unintended consequence of the proposed source contributing to a receptor, which may be 50-km away from the proposed source, but shows violation of the NAAQS due to other existing sources. If no SIL exists, there is no practical way to assess the proposed project's contribution.

A SIL, therefore, is absolutely necessary for a meaningful modeling analysis focused on protecting the environment. As a result, Golder is proposing a 1-hour SIL of 7.5 micrograms per cubic meter ($\mu\text{g}/\text{m}^3$) for example, which is equivalent to 4 percent of the AAQS of 188 $\mu\text{g}/\text{m}^3$. The 4-percent level has been used by EPA to set significant impact levels in other cases.

Golder will use the current default NO₂ to NO_x ratio of 0.75 to predict the 1-hour average NO₂ impacts from the modeled NO_x impacts. Alternatively, the ozone limiting method (OLM) or the plume volume molar ratio method (PVMRM) could be used to predict the NO₂ impacts. Compliance with the SIL will be based on the highest predicted 1-hour NO₂ concentration using a 5-year meteorological record.

If the 1-hour SIL is exceeded, GDNr will be contacted to provide a list of background NO₂ sources. The significant impact distance of the project will be determined and will represent the maximum receptor distance for the modeling area of a cumulative impact assessment.

PM_{2.5} Standard

A SIL for PM_{2.5} is yet to be finalized. EPA proposed the following SILs for PM_{2.5} in a Class II area on September 21, 2007 (Federal Register 54111, September 21, 2007):

- Option 1: Annual – 1.0 µg/m³, 24-Hour – 5.0 µg/m³
- Option 2: Annual – 0.8 µg/m³, 24-Hour – 4.0 µg/m³
- Option 3: Annual – 0.3 µg/m³, 24-Hour – 1.2 µg/m³

Based on discussion with GDNR, Golder will predict annual and 24-hour average impacts of direct PM_{2.5} emissions only and compare them to the most stringent proposed annual and 24-hour average PM_{2.5} SILs of 0.3 and 1.2 µg/m³, respectively. If the maximum predicted PM_{2.5} impacts are greater than the SIL, Golder will communicate with GDNR staff to ensure that compliance with the annual average and 24-hour average PM_{2.5} AAQS are addressed in a manner that is consistent with the most recent air modeling guidance for PM_{2.5} approved by GDNR and EPA.

Toxic Air Pollutants

Air quality impacts for toxic air pollutants emitted by the Facility will be assessed by following the GDNR procedures in the *Guideline for Ambient Impact Assessment of Toxic Air Pollutant Emissions* (Toxics Guidelines) (GDNR, 1998). Per those guidelines, the Industrial Source Complex Short-Term (ISCST3) model is identified as the recommended model. Golder will discuss with GDNR the use of AERMOD to provide maximum concentrations for the appropriate averaging times for each pollutant. These concentrations will then be compared to the latest acceptable ambient concentrations (AACs), which will be developed following the procedure in the Toxics Guidelines.

DISPERSION MODELING – PSD CLASS I AREAS

Model Selection and General Assumptions

The CALPUFF air modeling system (Version 5.8) will be used to predict the Project's maximum air quality concentrations at locations beyond 50 km from the Project. CALPUFF is a non-steady state Lagrangian puff long-range transport model that includes algorithms for chemical transformations (important for visibility controlling pollutants) and wet/dry deposition. CALPUFF will be used in a manner that is consistent with methodologies recommended in the following documents and previous discussions with the FLM.

- FLMs' AQRV Workgroup (FLAG) guidance document, finalized in December 2000 and referred to as the FLAG Phase I Report
- Interagency Workgroup on Air Quality Models (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long-Range Transport Impacts (EPA, 1998), referred to as the IWAQM Phase 2 report.

Parameter settings to be used in CALPUFF will be based on the latest regulatory guidance. Where the modeling guidance recommends regulatory model defaults, those defaults will be used. For ozone background concentrations, observed hourly ozone data for 2001 to 2003 from CASTNET and AIRS stations will be used. These data are available from the TRC website. A fixed monthly ammonia background concentration of 0.5 ppb will be used. Parameters will be set to generate an hourly relative humidity file for calculating 24-hour visibility impairment using CALPOST visibility method number 2. In addition, parameters will be set to calculate wet and dry (i.e., total) fluxes and concentrations at each PSD Class I area.

Project Modeled Emissions

The Project's emission, stack, and operating data as well as building dimensions will be modeled for the emission sources as indicated previously. This will include the CTs and fuel gas heater operating under normal operations. The CT emissions and stack parameters used for the far-field analysis will be from the load and ambient temperature that produces the highest CT emission rate. This will likely occur during base load and ambient temperature of 20°F. Because of the distances between the Project and PSD Class I areas and low-level release heights from the cooling tower, the PM emissions from the cooling tower will not be modeled.

PM emissions for the Project's CTs will be speciated into filterable and condensable components and into six particle size categories. The effect that each species has on visibility impairment is related to a parameter called the extinction coefficient. The higher the extinction coefficient, the greater is that species' effect on visibility. Filterable PM is speciated into coarse (PMC), fine (PMF), and elemental carbon (EC). The default extinction efficiencies for these species are 0.6, 1.0, and 10.0, respectively. PMC is PM with aerodynamic diameters greater than 2.5 microns. Both EC and PMF have aerodynamic diameters equal to or less than 2.5 microns. Condensable PM is comprised of sulfate (SO₄) and secondary organic aerosols (SOA). The extinction efficiencies for these species are $3 \times f(RH)$ and 4, respectively, where $f(RH)$ is the relative humidity factor.

The PM group will then be speciated into filterable and condensable species using the POSTUTIL utility program. Note that emissions for condensable inorganic PM are input directly to CALPUFF as SO₄.

PM speciation (PM₁₀ versus PM_{2.5}) will be developed based on the best available vendor information for the project's emission sources.

Building Downwash Considerations

The same methods used in the PSD Class II analyses to assess building downwash will be used in these analyses.

Meteorological Data

The far-field air modeling analyses will be conducted using the latest meteorological and geophysical databases which have been developed for use with the most recent versions of CALPUFF. These datasets were developed using CALMET Version 5.8 and were originally developed by VISTAS and recompiled for Version 5.8 by the FLM. The domain has 4-km spacing and covers the period from 2001 to 2003.

Receptors

The following PSD Class I areas are the only Class I areas located within 300 km of the Project site:

- Wolf Island National Wilderness Area (WNWA) - 101 km
- Okefenokee NWA (ONWA) - 162 km
- Cape Romain NWA (CRNWA) 167 km

The FLM has developed receptors to represent the boundary and internal areas of all PSD Class I areas. The analysis will use the receptors developed by the FLM for these Class I areas.

Significant Impact Analysis

Significant impact analyses will be performed to assess the Project's impacts at the PSD Class I areas. The maximum predicted SO₂, NO₂, and PM₁₀ concentrations due to the Project will be compared to EPA's proposed PSD Class I significant impact levels. If the Project's impacts exceed the proposed EPA PSD Class I significant impact levels, then a more detailed PSD Class I increment analysis will be performed

on a pollutant-specific basis. In the PSD Class I incremental analysis, PSD-increment affecting sources will be modeled for comparison to the allowable PSD Class I increments. The proposed PSD Class I significant impact levels are:

- SO₂: 3-hour – 1.0 µg/m³, 24-hour – 0.2 µg/m³, and annual average – 0.1 µg/m³
- NO₂: annual average – 0.1 µg/m³
- PM₁₀: 24-hour – 0.3 µg/m³, and annual average – 0.2 µg/m³

If a detailed PSD Class I impact assessment is required for one or more pollutants, an inventory of background PSD Class I increment-affecting sources will be developed with the assistance from GDNR.

AQRV Analyses

Q/D Approach

A revised FLAG document was published as a draft in June 2008, which has initial screening criteria that would exempt a source from AQRV impact review based on its annual emissions and distance from a Class I area. According to the revised FLAG document, a source located more than 50 km from a Class I area will have negligible impacts with respect to Class I AQRVs if its total SO₂, NO_x, PM₁₀, and SAM annual emissions (Q, in TPY, based on 24-hour maximum allowable emissions), divided by the distance from the Class I area (D, in km), Q/D, is 10 or less. Based on preliminary information provided using the Project's maximum annual emissions, the results of the Q/D analysis are presented in Table 2.

TABLE 2
PRELIMINARY SCREENING CRITERIA TO EXEMPT EMISSION SOURCE
FROM AQRV IMPACT REVIEW ¹

PSD Class I Area	Project Distance (D) (km) from PSD Class I Area	Q/D ²
Wolf Island NWA	101	2.5
Okefenokee NWA	162	1.5
Cape Romain NWA	167	1.5

¹ Draft FLMs' AQRV Workgroup (FLAG) Phase I Report- Revised (June 2008): If Q/D <10, then AQRV analysis may not be required.

² Q = 250.6 TPY (SO₂ = 100 TPY; NO_x = 40 TPY; PM₁₀ = 90 TPY; SAM = 20 TPY).

As shown in Table 2, the Q/D ratios for each of the PSD Class I areas within 300 km of the Project are less than 10. Therefore, in accordance with the 2008 draft FLAG guidance, the Project could be considered as not causing or contributing to impacts on AQRVs. Consequently, Mackinaw Power proposes that additional Class I AQRV analyses would not be required if the Project emissions meet the Q/D criterion and concurrence of the FLM is obtained.

The following Class I area methodology discussions are included to address the evaluation of AQRV impacts if this evaluation is deemed necessary.

Visibility

The project's impact on 24-hour visibility impairment in the form of regional haze will be compared with the FLM suggested visibility impairment criteria of 5 percent of the average background visual range of the top 5-percent visibility days.

Based on the FLAG document, current regional haze guidelines characterize a change in visibility by the change in the light-extinction coefficient (b_{ext}). The b_{ext} is the attenuation of light per unit distance due to the scattering and absorption by gases and particles in the atmosphere. A change in the extinction coefficient produces a perceived visual change. An index that simply quantifies the percent change in visibility due to the operation of a source is calculated as:

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

where: b_{exts} is the extinction coefficient calculated for the source

b_{extb} is the background extinction coefficient

The purpose of the visibility analysis is to calculate the extinction at each receptor for each day (24-hour period) of the year due to the project emissions.

The visibility analysis will be conducted for the applicable Class I areas using CALPUFF. The CALPUFF postprocessor model CALPOST will be used to calculate the combined visibility effects from the different pollutants that are emitted from the Project. Based on communications with the NPS, daily background extinction coefficients are to be calculated on an hour-by-hour basis using hourly RH data from CALMET and hygroscopic and non-hygroscopic extinction components specified in the FLAG document (Visibility Method 2). For each PSD Class I area in the region, the hygroscopic and non-hygroscopic components are 0.9 and 8.5 inverse megameters (Mm^{-1}), respectively. CALPOST calculates the percent extinction change for each day of the year. The default Rayleigh scattering term of $10 Mm^{-1}$ will be used for the analysis. The revised RH scattering enhancement factor $[f(RH)]$ growth curve published by EPA in 2003 will be used in the analysis.

Additional Visibility Assessment

The draft revised FLAG document recommends Visibility Method 8 as the method used to determine background light extinction, which differs from Visibility Method 2 by the use of monthly RH adjustment instead of hourly. Golder will also perform the visibility impairment analysis using Visibility Method 8 and follow the revised FLAG procedures. According to the revised procedure, the visibility threshold for concern is not exceeded if the 98th-percentile change in light extinction is less than 5 percent for each year modeled, when compared to the annual average natural condition value for the Class I area.

Sulfur and Nitrogen Deposition

Sulfur (S) and nitrogen (N) deposition for the Project will be calculated with CALPUFF at the PSD Class I areas. The deposition analysis criterion is based on the annual averaging period. The total deposition is estimated in units of kilogram per hectare per year (kg/ha/yr) of nitrogen or sulfur. CALPUFF is used to predict wet and dry deposition fluxes of various oxides of these elements.

For N deposition, the species include:

- Particulate ammonium nitrate (from species NO_3), wet and dry deposition
- Nitric acid (species nitric acid $[HNO_3]$), wet and dry deposition
- NO_x dry deposition
- Ammonium sulfate (species SO_4), wet and dry deposition

For S deposition, the species include:

- SO_2 , wet and dry deposition
- SO_4 , wet and dry deposition

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

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

The wet and dry sulfate and nitrate fluxes will be converted into total N and S fluxes using the POSTUTIL utility program.

PRECONSTRUCTION AMBIENT MONITORING ANALYSIS

In addition to comparison to the SILs, the Project's maximum pollutant impacts will also be compared to the *de minimis* air monitoring concentration to address preconstruction ambient air monitoring requirements under the PSD regulations. Should the Project's maximum pollutant impacts exceed a *de minimis* monitoring concentration, a request will be made that existing representative ambient air monitoring data be used to satisfy this requirement.

ADDITIONAL IMPACT ANALYSIS

The additional impact analyses required under PSD review include an analysis of the impacts of Project emissions on soils, vegetation, and visibility. The analysis of impacts due to associated growth in the area must also be addressed. To address such impacts, soil and vegetation types in the vicinity of the plant must be identified. A literature review will be conducted to identify the most recent data concerning threshold effect levels for the soil and vegetation types in the area. An assessment of air emissions impacts upon these values will then be prepared. Growth effects will be addressed qualitatively, including impacts due to secondary emissions from the facility.

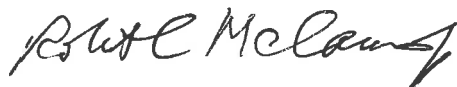
The analyses will conform to procedures recommended by the EPA, such as those in the document *A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils and Animals* (EPA 1980), and other appropriate literature.

CONCLUDING REMARKS

We look forward to receiving your comments on this protocol and working with the GDNR on this important project. If there are any questions, please contact me or Steve Marks at (352) 336-5600.

Sincerely,

GOLDER ASSOCIATES INC.



Robert C. McCann, Jr.
Principal



Steven R. Marks, C.C.M.
Associate

cc: Matthew Lydon, Mackinaw Power
Sal Mohammad, GAI Gainesville
Steven Moeller, GAI Atlanta
Jill Webster, U.S. Fish and Wildlife Service

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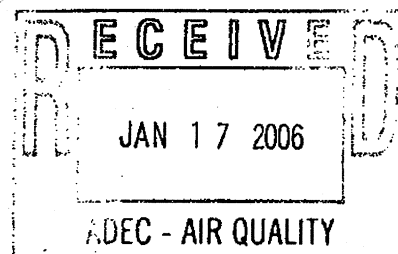
ATTACHMENT B

EPA LETTER APPROVING USE OF PVMRM IN ALASKA



UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 10
1200 Sixth Avenue
Seattle, WA 98101

13 JAN 2006



Reply To
Attn Of: OEA-095

Mr. Alan E. Schuler
Alaska Department of Environmental Conservation
Division of Air Quality, Air Permits Program
410 Willoughby Avenue, Suite 303
Juneau, AK 99801-1795

Dear Alan,

EPA Region 10 has reviewed the State of Alaska, 20 October 2004, letter request and the two technical documents prepared by MACTEC for the State of Alaska to determine if the Plume Volume Molar Ratio Method (PVMRM) should be designated as a refined technique and acceptable for use in quantifying ambient air nitrogen dioxide concentration impacts as well as for credits on a case-by-case basis, i.e., a non-guideline technique. In making the demonstration, PVMRM was coded into the AERMOD dispersion program as a non-default regulatory option and evaluated for performance against two data sets. The two documents are:

Sensitivity Analysis of PVMRM and OLM in AERMOD dated September 2004

Evaluation of Bias In AERMOD-PVMRM dated June 2005

The first report describes a sensitivity analysis of the PVMRM and Ozone Limiting Method (OLM) options embedded in the AERMOD dispersion code. The objective of the analysis is to determine how well nitrogen dioxide concentrations predicted by PVMRM compared to nitrogen dioxide estimates predicted by OLM Tier 1 and Tier 3, and the Ambient Ratio Method (ARM) under a range of dispersion cases, meteorological conditions, source characteristics, source types and source groupings. The report concludes that "...the PVMRM option appears to provide a more realistic treatment of the conversion of NO_x to NO_2 as a function of downwind distance from the source than OLM or the other NO_2 screen options."

The second report describes a performance evaluation of the PVMRM option embedded in the AERMOD dispersion code to determine the bias in model predictions. Bias is determined by utilizing two aircraft measurement studies of power plant plumes and two long term field studies. To judge bias or performance, a factor of two agreement between model predictions and observations was employed in the study. In addition, the power plant in-stack NO_2/NO_x ratio of 0.05 was used in the evaluations. The report concludes that "...the AERMOD-PVMRM algorithm is judged to provide unbiased estimates of the NO_2/NO_x ratio based on criteria that are comparable to, or more rigorous than, evaluations performed for other dispersion models that are judged to be refined, implying unbiased performance."

Based on the results and conclusions contained in the reports, it is my judgement that:

1. The first study adequately supports a Region 10 determination that the non-default PVMRM option as coded in the AERMOD dispersion program is an acceptable non-

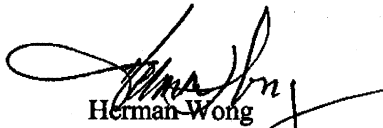
guideline technique to quantify ambient nitrogen dioxide concentration impacts from combustion sources emitting oxides of nitrogen through a stack.

2. The second study sufficiently supports a Region 10 determination that the non-default PVMRM option as coded in the AERMOD dispersion program results in unbiased concentration impacts and is acceptable for quantifying emission credits.
3. The use of the PVMRM option in the AERMOD dispersion code is limited to ambient air quality analyses prepared for the State of Alaska.
4. The use of the PVMRM option in the AERMOD dispersion code requires Regional Office Modeling Contact approval prior to its use in air quality analyses.

In a separate correspondence, Region 10 will request that the Office of Air Quality Planning and Standards (OAQPS) consider elevating PVMRM to a refined guideline technique in the Guideline on Air Quality Models. In 70FR68218, dated 09 November 2005, the Revision to the Guideline on Air Quality Models: Adoption of a Preferred General Purpose (Flat and Complex Terrain) Dispersion Model and Other Revisions; Final Rule, the PVMRM option in the AERMOD Modeling System (version 04300) is identified as a non-regulatory, non-default option in the preamble and in Appendix A to Appendix W, Section A.1.1, and currently being tested as a refined technique in Section 5.1.j. If and when OAQPS makes the elevation to a refined guideline technique, Region 10 approval for the use of PVMRM will no longer be required.

Should you have any questions, please don't hesitate to call me at 206.553.4858

Sincerely,



Herman Wong
Regional Office Modeling Contact

cc: Tyler Fox, OAQPS, Air Quality Modeling Group
Warren Peters, OAQPS, Model Clearinghouse.

From: Marks, Steve
Sent: Friday, June 11, 2010 11:56 AM
To: McCann, Bob
Subject: FW: Proposed Effingham Co power plant expansion project

fyi

From: Catherine_Collins@fws.gov [mailto:Catherine_Collins@fws.gov]
Sent: Friday, June 11, 2010 11:44 AM
To: Marks, Steve
Cc: Jill_Webster@fws.gov; Meredith_Bond@fws.gov
Subject: RE: Proposed Effingham Co power plant expansion project

Steve,

Yes. That is the correct interpretation. Let me know if you need anything else.

Catherine Collins, Environmental Engineer
U.S. Fish and Wildlife Service
Air Quality Branch
7333 W. Jefferson Ave., Suite 375
Lakewood, CO 80235-2034
303-914-3807
(303) 969-5444 fax
Catherine_Collins@fws.gov

"Marks, Steve" <Steve_Marks@golder.com>

06/11/2010 09:25 AM

To "Catherine_Collins@fws.gov" <Catherine_Collins@fws.gov>
cc "Meredith_Bond@fws.gov" <Meredith_Bond@fws.gov>,
"Jill_Webster@fws.gov" <Jill_Webster@fws.gov>

Subject RE: Proposed Effingham Co power plant expansion project

Catherine,

It was pointed out to me that your email response (below) only referenced the Wolf Island Wilderness Area and not the other two PSD Class I under FWS management that are located within 300 km of the proposed Effingham Co project. However, since Wolf Island is by far the closest of the three areas to

the project site, I took your response to mean that FWS was not requesting AQRV analyses for any of the three areas. Could you please confirm whether my understanding was correct? Thank you.

Best regards,

Steve

From: Catherine_Collins@fws.gov [mailto:Catherine_Collins@fws.gov]
Sent: Wednesday, May 05, 2010 2:27 PM
To: Marks, Steve
Cc: Meredith_Bond@fws.gov; Jill_Webster@fws.gov
Subject: RE: Proposed Effingham Co power plant expansion project

Mr. Marks,

Thank you for sending the information on modifications planned for the proposed Effingham Co Power Plant Expansion located in Effingham County Georgia. Based on the emissions and distance from Wolf Island National Wildlife Refuge described in your email, the U.S. Fish and Wildlife Service anticipates that modeling would not show any significant additional impacts to air quality related values (AQRV) at the wilderness area. Therefore, we are not requesting that a Class I AQRV analysis be included in the PSD permit application. Should the emissions or nature of the project change significantly, please contact us so that we might re-evaluate the situation.

This "waiver" of a Class I AQRV analysis does not indicate our agreement with any Class I AQRV analysis protocols or conclusions that applicants might make independent of Federal Land Manager review.

Please note that we are addressing only the need for an AQRV analysis. The state and/or EPA may have a different opinion regarding the need for a Class I increment analysis. Also, our comments only apply to the Class I area managed by the U.S. Fish and Wildlife Service.

Thank you for keeping us informed and involving the FWS in the project review. Please let me know if you have further questions or require additional clarification.

Catherine Collins, Environmental Engineer
U.S. Fish and Wildlife Service
Air Quality Branch
7333 W. Jefferson Ave., Suite 375
Lakewood, CO 80235-2034
303-914-3807
(303) 969-5444 fax
Catherine_Collins@fws.gov
Jill A Webster/FC/R9/FWS/DOI

04/27/2010 12:51 PM

To "Marks, Steve" <Steve_Marks@golder.com>
cc Catherine Collins/R9/FWS/DOI@FWS, Meredith Bond/R9/FWS/DOI@FWS
Subject RE: Proposed Effingham Co power plant expansion project [Link](#)

Mr. Marks.

I have forwarded your emails to Catherine Collins. She is the FWS air quality contact for the Class I areas listed in your correspondence.

Thanks.

Jill Webster, Environmental Scientist
US Fish and Wildlife Service
National Wildlife Refuge System
Branch of Air Quality
7333 W. Jefferson Ave., Suite 375
Lakewood, CO 80235-2017
(303) 914-3804
fax: (303) 969-5444

"Marks, Steve"
<Steve_Marks@golder.com>

04/27/2010 12:43 PM

To "Jill_Webster@fws.gov" <Jill_Webster@fws.gov>

cc "Meredith_Bond@fws.gov" <Meredith_Bond@fws.gov>, "Mohammad, Sal" <Sal_Mohammad@golder.com>, Peter Courtney <Peter.Courtney@dnr.state.ga.us>, Rosendo Majano <Rosendo.Majano@dnr.state.ga.us>, "McCann, Bob" <Bob_McCann@golder.com>

Subject RE: Proposed Effingham Co power plant expansion project

Based on the latest emissions, the estimated Q/D ratios for the proposed project are updated as follows:

PSD Class I Area	Project Distance (D) (km)	Q/D ²
	from PSD Class I Area	
Wolf Island NWA	101	4.2
Okefenokee NWA	162	2.6
Cape Romain NWA	167	2.6
Where Q = 427.7 TPY (SO ₂ = 25.3 TPY; NO _x = 473.8 TPY; PM ₁₀ = 111.4 TPY; SAM = 4.5 TPY).		

From: Marks, Steve
Sent: Tuesday, April 27, 2010 10:54 AM
To: 'Jill_Webster@fws.gov'
Cc: 'Meredith_Bond@fws.gov'; Mohammad, Sal
Subject: RE: Proposed Effingham Co power plant expansion project

Ms. Webster:

Since the original air modeling protocol was emailed to the USFWS on March 15, 2010 (see email

below), the proposed Effingham Co expansion project's emissions have changed and the revised project emissions are summarized in Table 1 below. Please use the updated emissions for your evaluation and feel free to contact me if you have any questions. Thank you.

Best Regards,
Steve Marks

TABLE 1
PRELIMINARY estimate of the maximum potential
annual emissions for the project

Pollutant	Project Maximum Emissions (TPY)	Significant Emission Rate (TPY)
SO ₂	25.3	40
NO _x	270.9	40
PM	112.3	25
PM ₁₀	111.4	15
PM _{2.5}	108.7	10
CO	473.8	100
SAM	4.5	7
VOC	45.8	40

From: Marks, Steve
Sent: Monday, March 15, 2010 4:26 PM
To: 'Jill_Webster@fws.gov'
Cc: Meredith_Bond@fws.gov
Subject: RE: Proposed Effingham Co power plant expansion project

Ms. Webster:

Please find attached Golder's air modeling protocol for the proposed Effingham Co power plant expansion project. If you have any comments or questions, please contact me. Thank you.

Best Regards,
Steve

Steven R. Marks, M.S., C.C.M. | Associate, Senior Scientist | Golder Associates Inc.
6026 NW 1st Place, Gainesville, Florida, USA 32607
T: +1 (352) 336-5600 Ext. 21139 | F: +1 (352) 336-6603 | E: smarks@golder.com |
www.golder.com

Work Safe, Home Safe

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APPENDIX D

DETAILS OF SOURCE PARAMETERS USED IN THE NAAQS MODELING ANALYSES

TABLE D-1
SUMMARY OF NO₂ SOURCES MODELED IN THE NAAQS ANALYSIS

Facility ID	Facility Name Emission Unit Description	EU ID	Model ID Name	UTM Location		Stack Parameters								Stack Parameter Data Source ^a	NO ₂ Emission Rate ^a			
				East (m)	North (m)	Height		Diameter		Temperature		Velocity			(lb/hr)	(g/s)		
						ft	m	ft	m	°F	K	ft/s	m/s					
04-13-103-00012	Effingham county power llc													Permit No. 4911-103-0012-V-03-0; modeled parameters based on same data as project				
	Auxiliary Boiler	AB1	EXAUXBLR	473173.145	3,571,169.79	39.1	11.9	2.6	0.79	476.0	519.8	30.57	9.32		0.437	0.055		
	Fuel Preheater	FP1	EXFUELHT	473039.726	3,571,175.57	19.2	5.9	2.6	0.79	825.0	713.7	9.32	2.84		0.810	0.102		
	GE 7FA Combustion Turbine	CTG1	EXCT1	473171.521	3,571,206.50	165.0	50.3	19.0	5.79	262.7	401.3	38.6	11.76		gas	25.1	3.2	
	GE 7FA Combustion Turbine	CTG2	EXCT2	473204.313	3,571,244.38	165.0	50.3	19.0	5.79	262.7	401.3	38.6	11.76		gas	25.1	3.2	
	TOTAL														51.4	6.5		
04-13-103-00007	Georgia-pacific consumer products lp													Data provided by Georgia Pacific 5/10				
	Boiler #3 stack	BO01	GPACB03	481,091	3,577,180	384.9	117.3	7.25	2.2	295.1	419.3	66.0	20.1		168.8	21.3		
	Boiler #4 Stack	BO02	GPAB04	481,108	3,577,194	384.9	117.3	7.25	2.2	295.1	419.3	66.0	20.1		168.8	21.3		
	Boiler #5 Stack	BO03	GPAB05	481,136	3,577,219	384.9	117.3	7.25	2.2	295.1	419.3	66.0	20.1		168.8	21.3		
	Boiler #3,#4,#5 stacks		GPAB345	481,108	3,577,194	384.9	117.3	7.2	2.2	295.1	419.3	66.0	20.1		506.4	63.8		
	Paper Machine #18 Stack	PM01	GPAPM03	480,970	3,577,173	104.4	31.8	7.00	2.1	119.9	322.0	69.3	21.1		6.0	0.8		
	Paper Machine #16 Stack	PM02	GPAPM01	480,876	3,577,095	104.4	31.8	7.00	2.1	119.9	322.0	61.0	18.6		2.3	1.0		
	Paper Machine #17 Stack	PM03	GPAPM02	480,923	3,577,135	104.4	31.8	7.00	2.1	119.9	322.0	61.0	18.6		2.3	0.3		
	Paper Machine #19 Stack	PM04	GPAPM04	480,828	3,577,057	104.4	31.8	7.00	2.1	119.9	322.0	61.0	18.6		2.3	0.8		
	Paper Machine #16,#17,#19 Stacks		GPAPM124	480,828	3,577,057	104.4	31.8	7.0	2.1	119.9	322.0	61.0	18.6		6.91	2.04		
	Paper Machine # 20 Stack	PM05	GPAPM05	480,768	3,577,011	92.9	28.3	4.80	1.5	119.9	322.0	129.7	39.5		7.2	0.9		
	CT #1 Exhaust Stack	CT01	GPACT1	481,006	3,577,188	165.0	50.3	3.67	1.12	500.1	533.2	845.2	257.7		290.1	36.6		
	CT #2 Exhaust Stack	CT02	GPACT2	481,017	3,577,197	165.0	50.3	3.67	1.12	500.1	533.2	845.2	257.7		290.1	36.6		
	CT #1, CT #2		GPACT1&2	481,017	3,577,197	165.0	50.3	3.67	1.12	500.1	533.2	845.2	257.7		580.2	73.1		
		TOTAL														1099.5	139.70	
	04-13-103-00014	Georgia power - plant mcintosh combined cycle														Stack Data provided by Georgia EPD 5/6/10		
		Stack for CT10A and DB10A	CC10	GPMCT10A	484,212	3,579,887	160.0	48.8	19.0	5.8	167.0	348.2	51.2		15.6		25.8	3.3
Stack for CT10B and DB10B		CC10	GPMCT10B	484,212	3,579,887	160.0	48.8	19.0	5.8	167.0	348.2	51.2	15.6	25.8	3.3			
Stack for CT11B and DB11B		CC11	GPMCT11A	484,212	3,579,887	160.0	48.8	19.0	5.8	167.0	348.2	51.2	15.6	25.8	3.3			
Stack for CT11A and DB11A		CC11	GPMCT11B	484,212	3,579,887	160.0	48.8	19.0	5.8	167.0	348.2	51.2	15.6	25.8	3.3			
	CT10,DB10,CT11,DB11		GPMC1011	484,212	3,579,887	160.0	48.8	19.0	5.8	167.0	348.2	51.2	15.6	TOTAL	103.2	13.00		
04-13-103-00003	Savannah electric - plant mcintosh													Stack Data provided by Georgia EPD 5/6/10				
	Combustion Turbine 1-8	CT01	SECT18	484,184	3,579,865	64.0	19.5	14.3	4.3	960.0	788.7	141.0	43.0		122.4	15.4		
	Steam Generator Unit	SG01	SESG01	484,165	3,579,887	400.0	121.9	11.5	3.5	307.0	425.9	79.0	24.1		931.0	117.3		
	Boiler Stack	SB01	SEBS01			30.0			0.0		255.4		0.0		3.6	0.5		
	TOTAL														1057.0	133.2		

TABLE D-1
SUMMARY OF NO₂ SOURCES MODELED IN THE NAAQS ANALYSIS

Facility ID	Facility Name Emission Unit Description	EU ID	Model ID Name	UTM Location		Stack Parameters								Stack Parameter Data Source ^a	NO ₂ Emission Rate ^a	
				East (m)	North (m)	Height		Diameter		Temperature		Velocity			(lb/hr)	(g/s)
						ft	m	ft	m	°F	K	ft/s	m/s			
1360-0026	SCE&G-Jasper Co. Generating Facility													SC DHEC inventory files 5/3/10		
	Turbines 1-3	--	SCEGT123	488,357	3,580,065	190.0	57.9	18.0	5.5	278.0	409.8	72.6	22.1	TOTAL	357.0	45.0
1360-0043	BJWater & Sewer Authority Generator #1	--	BJWSG01	488,551	3,579,794	16	4.9	1.3	0.4	927	770.4	208	63.4	SC DHEC inventory files 5/3/10 TOTAL	12.8	1.6
04-13-051-00010	Weyerhaeuser company - port wentworth mill													Stack Data provided by Georgia EPD 5/6/10		
	Chip Bin - NCG system	--		485,328	3,557,816		0.0		0.0	255.4			0.0			0.0
	Pulping and Evaporators NCG system - CNCG	--		485,328	3,557,816		0.0		0.0	255.4			0.0			0.0
	Bleached Stock HD Storage Vents	--		485,092	3,557,993	96.0	29.3	4.9	1.5	100.0	310.9	1.3	0.4			0.0
	Combination Boiler	PB04	WCPB04	485,328	3,557,816	317.0	96.6	13.5	4.1	340.0	444.3	31.0	9.4		192.6	24.3
	Woodyard Unloading, Storage and Conveyors	DC01	WCDC01	485,328	3,557,838		0.0		0.0	255.4			0.0			0.0
	Lime Kiln	LK01	WCLK01	485,328	3,557,816	150.0	45.7	5.0	1.5	350.0	449.8	41.6	12.7		31.2	3.9
	Bleach Plant Scrubber	BL01	WCBL01	485,328	3,557,838	155.0	47.2	1.5	0.5	140.0	333.2	60.4	18.4			0.0
	Pulp Machine Vents Merged Equivalent	MP01	WCMP01	485,328	3,557,816	60.0	18.3	8.9	2.7	140.0	333.2	82.0	25.0			0.0
	Recovery Boiler West Stack	RE01	WCRE01	485,328	3,557,816	317.0	96.6	9.8	3.0	350.0	449.8	64.0	19.5		174.3	22.0
	Smelt Dissolving Tank East Stack	SM01	WCSM01	485,328	3,557,816	317.0	96.6	3.4	1.0	170.0	349.8	39.5	12.0		3.2	0.4
	Causticizing Area Merged Stack Equivalent	CA01	WCCA01	485,328	3,557,816	30.0	9.1	3.2	1.0	100.0	310.9	19.8	6.0			0.0
	Weak Liquor Storage Vents	--		485,328	3,557,816	30.0	9.1	4.9	1.5	180.0	355.4	1.3	0.4			0.0
														TOTAL	401.3	50.6
04-13-051-00006	Georgia power - plant kraft													Stack Data provided by Georgia EPD 5/6/10		
	Stack for Steam Generator Units 1-4	ST01	GPKST01	486,251	3,556,916	275.0	83.8	22.0	6.7	285.0	413.7	37.7	11.5		1,854.0	233.6
	Stack for CT1	S1	GPKSCT1	486,269	3,556,883	25.0	7.6	8.0	2.4	774.0	685.4	150.2	45.8		299.2	37.7
														TOTAL	2153.2	271.3
1360-0019	SCE&G-Hardeeville													SC DHEC inventory files 5/3/10		
	Combustion Turbine 1	CT1	SCEGHCT1	492,703	3,573,257	30.0	9.1	11.0	3.4	775.0	685.9	86.0	26.2	TOTAL	153.7	19.4
04-13-051-00110	Savannah sugar refinery													Stack Data provided by Georgia EPD 5/6/10		
	A Boiler	U158	SSRU158	486,146	3,556,429	142.0	43.3	8.5	2.6	350.0	449.8	50.0	15.2	estimated	13.0	1.6
	B Boiler	U159	SSRU159	486,146	3,556,429	142.0	43.3	8.5	2.6	350.0	449.8	50.0	15.2		0.2	0.0
	C Boiler	U160	SSRU160	486,146	3,556,429	142.0	43.3	8.5	2.6	350.0	449.8	50.0	15.2		7.3	0.9
	ABC Boilers		SSRABC	486,146	3,556,429	142.0	43.3	8.5	2.6	350.0	449.8	50.0	15.2		20.5	2.6
	D Boiler	U161	SSRU161			150.0	45.7	8.5	2.6	350.0	449.8	51.0	15.5		236.6	29.8
	E Boiler	U163	SSRU163				0.0		0.0	255.4			0.0		6.9	0.9

TABLE D-1
SUMMARY OF NO₂ SOURCES MODELED IN THE NAAQS ANALYSIS

Facility ID	Facility Name Emission Unit Description	EU ID	Model ID Name	UTM Location		Stack Parameters								Stack Parameter Data Source ^a	NO ₂ Emission Rate ^a	
				East (m)	North (m)	Height		Diameter		Temperature		Velocity			(lb/hr)	(g/s)
						ft	m	ft	m	°F	K	ft/s	m/s			
04-13-051-00012	Char Kiln	U162	SSRU162			91.0		0.0		255.4		0.0		0.9	0.1	
	DE Boilers, Kiln		SSRDEKN	486,146	3,556,429	150.0	45.7	8.5	2.6	350.0	449.8	51.0	15.5	244.4	30.8	
04-13-051-00007	Nustar asphalt refining, llc													Stack Data provided by Georgia EPD 5/6/10		
	No. 4 Boiler	B004	NARB004	488,103	3,552,602										5.2	0.65
	No. 5 Boiler	B005	NARB005	488,103	3,552,602										5.8	0.73
	Nos. 4 and 5 Boilers		NARB045	488,103	3,552,602	180.0	54.9	3.5	1.1	425.0	491.5	6.0	258.7		11.0	1.4
	No. 1 Unit Fired Heater	F001	NARF001	488,103	3,552,602	131.0	39.9	5.0	1.5	425.0	491.5	9.8	3.0	Not modeled	0.0	0.00
	No. 2 Unit Fired Heater	F002	NARF002	488,103	3,552,602	131.0	39.9	5.0	1.5	425.0	491.5	9.8	3.0	Not modeled	0.0	0.00
	Nos. 1 and 2 Heaters		NARF012	488,103	3,552,602	131.0	39.9	5.0	1.5	425.0	491.5	9.8	3.0		0.0	0.0
04-13-051-00148	International Paper - Savannah															
	Recovery Furnace #15 Stack	RF15	IPRF15	488,622	3,552,047	350.0	106.7	13.5	4.1	350.0	449.8	75.0	22.9	Stack Data provided by Georgia EPD 5/6/10	188.0	23.7
	Recovery Furnace #15 Smelt Dissolving Tank Vent	RF10	IPRF16	488,622	3,552,047	274.0	83.5	6.2	1.9	170.0	349.8	25.0	7.6		5.0	0.6
	Lime Kiln #7 ESP Stack	LK7	IPLK7	488,622	3,552,047	270.0	82.3	6.0	1.8	450.0	505.4	50.0	15.2		60.5	7.6
	Lime Area	OPG8	IPOPG8	488,622	3,552,047											0.0
	Power Boiler #13 Stack	PB13	IPPB13	488,622	3,552,047	350.0	106.7	13.3	4.1	350.0	449.8	50.0	15.2		825.6	104.0
															1,079.1	136.0
0360-0006	Arizona chemical corp.													Stack Height obtained from Application No. 18208		
	SB-1T Top Temporary Boiler	TB01	ACCTB01	488,501	3,551,247	15.0	4.6								3.9	0.5
	S/B 7T Temporary Packaged Steam Boiler	TB02	ACCTB02	488,501	3,551,247	15.0	4.6								9.7	1.2
	Steam Boiler	E101	ACCTB04	488,501	3,551,247	134.0	40.8	4.92	1.5	250.1	394.3	49.20	15.0	estimated	27.9	3.5
	Combined Units		ACCALL	488,501	3,551,247	134.0	40.8	4.9	1.5	250.1	394.3	49.2	15.0	TOTAL	41.5	5.2
0360-0048	Santee Cooper - Hilton Head													SC DHEC inventory files 5/3/10		
	Unit 1	--	SCHHU1	528,328	3,563,427	32.0	9.8	12.5	3.8	917.0	764.8	100.0	30.5		414.6	52.2
	Unit 2	--	SCHHU2	528,328	3,563,458	32.0	9.8	12.3	3.7	933.0	773.7	100.0	30.5		414.6	52.2
	Unit 3	--	SCHHU3	528,328	3,563,489	32.0	9.8	15.0	4.6	990.0	805.4	120.0	36.6		488.6	61.6
	Unit 1, Unit 2, Unit 3		SCHH	528,328	3,563,458	32.0	9.8	12.3	3.7	933.0	773.7	100.0	30.5	TOTAL	1,317.8	166.0
0360-0048	SCE&G - Burton Gas Turbine													SC DHEC inventory files 5/3/10		
	CT1	--	SCEGBCT1	526,192	3,588,622	26.0	7.9	10.0	3.0	865.0	735.9	76.0	23.2		130.2	16.4

TABLE D-1
SUMMARY OF NO₂ SOURCES MODELED IN THE NAAQS ANALYSIS

Facility ID	Facility Name Emission Unit Description	EU ID	Model ID Name	UTM Location		Stack Parameters								Stack Parameter Data Source ^a	NO ₂ Emission Rate ^a	
				East (m)	North (m)	Height		Diameter		Temperature		Velocity			(lb/hr)	(g/s)
						ft	m	ft	m	°F	K	ft/s	m/s			
0360-0004	CT2	--	SCEGBCT2	526,244	3,588,622	26.0	7.9	10.0	3.0	865.0	735.9	76.0	23.2	TOTAL	130.0	16.4
	CT3	--	SCEGBCT3	526,244	3,588,591	26.0	7.9	10.0	3.0	865.0	735.9	76.0	23.2		130.0	16.4
	CT1,CT2,CT3		SCGEB	526,244	3,588,622	26.0	7.9	10.0	3.0	865.0	735.9	76.0	23.2		390.2	49.2
	US Marines Corps Air Station													SC DHEC inventory files 5/3/10		
	FC1/2 - boilers 1&2	--	USMC1	526,364	3,591,621	73.0	22.3	4.0	1.2	269.0	404.8	10.0	3.0	estimated	14.9	1.9
	Microturbines	--	USMC2	526,355	3,591,605	6.9	2.1	0.8	0.2	170.0	349.8	51.2	15.6		2.2	0.3
	FC3 - boiler 3	--	USMC3	528,259	3,592,289	25.0	7.6	1.1	0.3	300.0	422.0	10.0	3.0		0.5	0.1
	TS5 - T10 Test Cell Stack 1	--	USMC4	525,165	3,593,059	40.0	12.2	13.8	4.2	203.0	368.2	15.1	4.6		81.8	10.3
	TS5 - T10 Test Cell Stack 2	--	USMC5	525,165	3,593,059	40.0	12.2	13.8	4.2	687.0	637.0	98.1	29.9		81.8	10.3
	TS5 - T10 Test Cell Stack 1 & 2		USMC45	525,165	3,593,059	40.0	12.2	13.8	4.2	203.0	368.2	15.1	4.6		163.6	20.6
	TS3 - Test Stand 966-1	--	USMC6	525,342	3,593,028	5.0	1.5	1.0	0.3	200.0	366.5	10.0	3.0		7.2	0.9
	TS4 - Test Stand 1097-1	--	USMC8	525,206	3,593,022	5.0	1.5	1.0	0.3	200.0	366.5	10.0	3.0		7.2	0.9
	TS3,TS4-1		USMC68	525,342	3,593,028	5.0	1.5	1.0	0.3	200.0	366.5	10.0	3.0		14.4	1.8
	TS3 - Test Stand 966-2	--	USMC7	525,342	3,593,028	302.5	92.2	10.0	3.0	200.0	366.5	10.0	3.0		64.7	8.2
	TS4 - Test Stand 1097-2	--	USMC9	525,206	3,593,022	302.5	92.2	10.0	3.0	200.0	366.5	10.0	3.0		64.7	8.2
	TS3,TS4-2		USMC79	525,342	3,593,028	302.5	92.2	10.0	3.0	200.0	366.5	10.0	3.0		129.5	16.3
														TOTAL	325.1	41.0
0360-0044	Hilton Head No. 1 Public Service District													SC DHEC inventory files 5/3/10		
	Generator 1	--	HH1	528,324	3,563,841	13.8	4.2	45.2	13.8	820.0	710.9	151.3	46.1		23.1	2.9
	Generator 2	--	HH2	528,324	3,563,841	12.0	3.7	39.4	12.0	970.0	794.3	454.0	138.4		7.1	0.9
														TOTAL	30.3	3.8

^a Pertinent permit, application, tables, Georgia EPD and South Carolina DHEC data used. In some cases, no data were available. Engineering estimates are used when data were not available from other sources. See Table D-3. Estimated stack parameters highlighted in yellow.

TABLE D-2

Facility ID	Facility Name Emission Unit Description	EU ID	Model ID Name	East (m)	North (m)	Height		Diameter		Temperature		Velocity		Stack Parameter Data Source ^a	Rate ^a		
						ft	m	ft	m	°F	K	ft/s	m/s		(lb/hr)	(g/s)	
04-13-103-00012	Effingham county power llc													Permit No. 4911-103-0012-V-03-0; modeled parameters based on same data as project			
		Auxiliary Boiler	AB1	EXAUXBLR	473173.15	3,571,169.79	39.1	11.9	2.6	0.79	476.0	519.8	30.57		9.32	0.14	0.02
		Fuel Preheater	FP1	EXFUELHT	473039.73	3,571,175.57	19.2	5.9	2.6	0.79	825.0	713.7	9.32		2.84	0.06	0.01
		GE 7FA Combustion Turbine	CTG1	EXCT1	473171.52	3,571,206.50	165.0	50.3	19.0	5.79	356.4	453.4	37.8		11.5	9.7	1.22
		GE 7FA Combustion Turbine	CTG2	EXCT2	473204.31	3,571,244.38	165.0	50.3	19.0	5.79	356.4	453.4	37.8		11.5	9.7	1.22
																19.6	2.5
	8-Cell Cooling Tower Cell 1		EXCOOL01	473,286.46	3,571,069.72	43.0	13.10	33.0	10.06	305.0	424.8	28.24	8.61	0.149	0.019		
	8-Cell Cooling Tower Cell 2		EXCOOL02	473,296.02	3,571,080.61	43.0	13.10	33.0	10.06	305.0	424.8	28.24	8.61	0.149	0.019		
	8-Cell Cooling Tower Cell 3		EXCOOL03	473,305.31	3,571,091.90	43.0	13.10	33.0	10.06	305.0	424.8	28.24	8.61	0.149	0.019		
	8-Cell Cooling Tower Cell 4		EXCOOL04	473,315.14	3,571,102.79	43.0	13.10	33.0	10.06	305.0	424.8	28.24	8.61	0.149	0.019		
	8-Cell Cooling Tower Cell 5		EXCOOL05	473,324.44	3,571,114.21	43.0	13.10	33.0	10.06	305.0	424.8	28.24	8.61	0.149	0.019		
	8-Cell Cooling Tower Cell 6		EXCOOL06	473,334.00	3,571,125.23	43.0	13.10	33.0	10.06	305.0	424.8	28.24	8.61	0.149	0.019		
	8-Cell Cooling Tower Cell 7		EXCOOL07	473,343.43	3,571,136.26	43.0	13.10	33.0	10.06	305.0	424.8	28.24	8.61	0.149	0.019		
	8-Cell Cooling Tower Cell 8		EXCOOL08	473,352.81	3,571,147.84	43.0	13.10	33.0	10.06	305.0	424.8	28.24	8.61	0.149	0.019		
																1.19	0.15
														TOTAL		20.8	2.6
	04-13-103-00007	Georgia-pacific consumer products lp													Stack Data provided by Georgia Pacific 5/10; emissions based on permit		
			Boiler #3 stack	BO01	GPACB03	481,091	3,577,180	385	117	7.2	2.2	295.1	419.3	66.0		20.1	29.5
Boiler #4 Stack			BO02	GPAB04	481,108	3,577,194	385	117	7.2	2.2	295.1	419.3	66.0	20.1		29.5	3.72
Boiler #5 Stack			BO03	GPAB05	481,136	3,577,219	385	117	7.2	2.2	295.1	419.3	66.0	20.1		29.5	3.72
Boiler #3,#4,#5 stacks				GPAB345	481,108	3,577,194	384.9	117.3	7.2	2.2	295.1	419.3	66.0	20.1		88.62	11.17
Paper Machine #18 Stack		PM01	GPAPM03	480,970	3,577,173	104	32	7.0	2.1	119.9	322.0	69.3	21.1	2.4	0.31		
Paper Machine #16 Stack		PM02	GPAPM01	480,876	3,577,095	104	32	7.0	2.1	119.9	322.0	61.0	18.6	4.1	0.51		
Paper Machine #17 Stack		PM03	GPAPM02	480,923	3,577,135	104	32	7.0	2.1	119.9	322.0	61.0	18.6	3.8	0.48		
Paper Machine #19 Stack		PM04	GPAPM04	480,828	3,577,057	104	32	7.0	2.1	119.9	322.0	61.0	18.6	1.3	0.16		
Paper Machine #16,#17,#19 Stacks			GPAPM124	480,828	3,577,057	104.4	31.8	7.0	2.1	119.9	322.0	61.0	18.6	9.20	1.16		
Paper Machine # 20 Stack		PM05	GPAPM05	480,768	3,577,011	93	28	4.8	1.5	119.9	322.0	129.7	39.5	0.3	0.04		
CT #1 Exhaust Stack		CT01	GPACT1	481,006	3,577,188	165	50	3.7	1.1	500.1	533.2	845.2	257.7	6.6	0.83		
CT #2 Exhaust Stack		CT02	GPACT2	481,017	3,577,197	165	50	3.7	1.1	500.1	533.2	845.2	257.7	6.6	0.83		
CT #1, CT #2		GPACT1&2	481,017	3,577,197	165.0	50.3	3.7	1.1	500.1	533.2	845.2	257.7	13.20	1.66			
													TOTAL		113.5	14.30	
04-13-103-00014	Georgia power - plant mcintosh combined cycle													Stack Data provided by Georgia EPD 5/6/10			
		Stack for CT10A and DB10A	CC10	GPMCT10A	484,212	3,579,887	160.0	48.8	19.0	5.8	167.0	348.2	51.2		15.6	17.0	2.14
		Stack for CT10B and DB10B	CC10	GPMCT10B	484,212	3,579,887	160.0	48.8	19.0	5.8	167.0	348.2	51.2		15.6	17.0	2.14
		Stack for CT11B and DB11B	CC11	GPMCT11A	484,212	3,579,887	160.0	48.8	19.0	5.8	167.0	348.2	51.2		15.6	17.0	2.14
		Stack for CT11A and DB11A	CC11	GPMCT11B	484,212	3,579,887	160.0	48.8	19.0	5.8	167.0	348.2	51.2		15.6	17.0	2.14
		CT10 DB10 CT11 DB11		GPACT1011	484,212	3,579,887	160.0	48.8	19.0	5.8	167.0	348.2	51.2		15.6		
														TOTAL		67.8	8.54

TABLE D-2
SUMMARY OF PM₁₀ SOURCES MODELED IN THE NAAQS ANALYSIS

Facility ID	Facility Name Emission Unit Description	EU ID	Model ID Name	UTM Location		Stack Parameters								Stack Parameter Data Source ^a	PM ₁₀ Emission Rate ^a	
				East (m)	North (m)	Height		Diameter		Temperature		Velocity			(lb/hr)	(g/s)
						ft	m	ft	m	°F	K	ft/s	m/s			
04-13-103-00003	Savannah electric - plant mcintosh													Stack Data provided by Georgia EPD 5/6/10		
	Combustion Turbine 1-8	CT01	SECT18	484,184	3,579,865	64.0	19.5	14.3	4.3	960.0	788.7	141.0	43.0		136.2	17.16
	Steam Generator Unit	SG01	SESG01	484,165	3,579,887	400.0	121.9	11.5	3.5	307.0	425.9	79.0	24.1		335.2	42.23
	Boiler Stack	SB01	SEBS01			30.0			0.0	255.4			0.0	not modeled	0.1	0.01
														TOTAL	471.4	59.4
1360-0026	SCE&G-Jasper Co. Generating Facility													SC DHEC inventory files 5/3/10		
	Turbines 1-3	--	SCEGT123	488,357	3,580,065	190.0	57.9	18.0	5.5	278.0	409.8	72.6	22.1	TOTAL	163.2	20.56
04-13-051-00010	Weyerhaeuser company - port wentworth mill													Stack Data provided by Georgia EPD 5/6/10		
	Bleached Stock HD Storage Vents	--		485,092	3,557,993	96.0	29.3	4.9	1.5	100.0	310.9	1.3	0.4	Not modeled		0.00
	Combination Boiler	PB04	WCPB04	485,328	3,557,816	317.0	96.6	13.5	4.1	340.0	444.3	31.0	9.4	Not modeled		0.00
	Woodyard Unloading, Storage and Conveyors	DC01	WCDC01	485,328	3,557,838	32.8	10.0	32.8	10.0	32.0	273.2	0.3	0.1	Fugitive est. as pt source	38.5	4.85
	Lime Kiln	LK01	WCLK01	485,328	3,557,816	150.0	45.7	5.0	1.5	350.0	449.8	41.6	12.7		7.4	0.94
	Bleach Plant Scrubber	BL01	WCBL01	485,328	3,557,838	155.0	47.2	1.5	0.5	140.0	333.2	60.4	18.4	Not modeled		0.00
	Pulp Machine Vents Merged Equivalent	MP01	WCMP01	485,328	3,557,816	60.0	18.3	8.9	2.7	140.0	333.2	82.0	25.0	Not modeled		0.00
	Recovery Boiler West Stack	RE01	WCRE01	485,328	3,557,816	317.0	96.6	9.8	3.0	350.0	449.8	64.0	19.5		33.2	4.18
	Smelt Dissolving Tank East Stack	SM01	WCSM01	485,328	3,557,816	317.0	96.6	3.4	1.0	170.0	349.8	39.5	12.0		71.0	8.94
	Causticizing Area Merged Stack Equivalent	CA01	WCCA01	485,328	3,557,816	30.0	9.1	3.2	1.0	100.0	310.9	19.8	6.0	Not modeled		0.00
	Weak Liquor Storage Vents	--		485,328	3,557,816	30.0	9.1	4.9	1.5	180.0	355.4	1.3	0.4	Not modeled		0.00
													TOTAL	150.1	18.9	
04-13-051-00006	Georgia power - plant kraft													Stack Data provided by Georgia EPD 5/6/10		
	Stack for Steam Generator Units 1-4	ST01	GPKST01	486,251	3,556,916	275	83.8	22	6.7	285	413.7	37.7	11.5		1095.1	137.99
	Stack for CT1	S1	GPKSCT1	486,269	3,556,883	25	7.6	8	2.4	774	685.4	150.17	45.8		4.1	0.51
													TOTAL	1099.2	138.5	
04-13-051-00110	Savannah sugar refinery													Stack Data provided by Georgia EPD 5/6/10		
	A Boiler	U158	SSRU158	486,146	3,556,429	142.0	43.3	8.5	2.6	350.0	449.8	50.0	283.2	estimated	24.0	3.0
	B Boiler	U159	SSRU159	486,146	3,556,429	142.0	43.3	8.5	2.6	350.0	449.8	50.0	15.2		12.2	1.5
	C Boiler	U160	SSRU160	486,146	3,556,429	142.0	43.3	8.5	2.6	350.0	449.8	50.0	15.2		21.8	2.7
	ABC Boilers		SSRABC	486,146	3,556,429	142.0	43.3	8.5	2.6	350.0	449.8	50.0	283.2		58.0	7.3
	D Boiler	U161	SSRU161			150.0	45.7	8.5	2.6	350.0	449.8	51.0	15.5		35.4	4.5
	E Boiler	U163	SSRU163				0.0		0.0	255.4			0.0	Not modeled		0.0
	Char Kiln	U162	SSRU162			91.0			0.0	255.4			0.0		0.1	0.0
	DE Boilers, Kiln		SSRDEKN	486,146	3,556,429	150.0	45.7	8.5	2.6	350.0	449.8	51.0	15.5		35.5	4.5
													TOTAL	93.5	11.8	

TABLE D-2
SUMMARY OF PM₁₀ SOURCES MODELED IN THE NAAQS ANALYSIS

Facility ID	Facility Name Emission Unit Description	EU ID	Model ID Name	UTM Location		Stack Parameters								Stack Parameter Data Source ^a	PM ₁₀ Emission Rate ^a		
				East (m)	North (m)	Height		Diameter		Temperature		Velocity			(lb/hr)	(g/s)	
						ft	m	ft	m	°F	K	ft/s	m/s				
04-13-051-00012	Nustar asphalt refining, llc													Stack Data provided by Georgia EPD 5/6/10			
	No. 4 Boiler	B004	NARB004	488,103	3,552,602										26.4	3.33	
	No. 5 Boiler	B005	NARB005	488,103	3,552,602										29.0	3.66	
	Nos. 4 and 5 Boilers		NARB045	488,103	3,552,602	180.0	54.9	3.5	1.1	425.0	491.5	6.0	258.7		55.4	6.98	
	No. 1 Unit Fired Heater	F001	NARF001	488,103	3,552,602	131.0	39.9	5.0	1.5	425.0	491.5	9.8	3.0		11.9	1.50	
	No. 2 Unit Fired Heater	F002	NARF002	488,103	3,552,602	131.0	39.9	5.0	1.5	425.0	491.5	9.8	3.0		11.9	1.50	
	Nos. 1 and 2 Heaters		NARF012	488,103	3,552,602	131.0	39.9	5.0	1.5	425.0	491.5	9.8	3.0		23.7	3.0	
	Crude Oil Distillation Tower No. 1	D001	NARD001	488,103	3,552,602										0.0	0.00	
	Crude Oil Distillation Tower No. 2	D002	NARD002	488,103	3,552,602										0.0	0.00	
	Distillation Towers Vent		NARD012	488,103	3,552,602	30	9.1	0.5	0.2	70	294.3	3	0.9	Not modeled	0.0	0.00	
	Hot Oil Heater	H001	NARH001	488,103	3,552,602									Not modeled	0.2	0.02	
														TOTAL	79.3	10.0	
04-13-051-00007	International Paper - Savannah													Stack Data provided by Georgia EPD 5/6/10			
	Recovery Furnace #15 Stack	RF15	IPRF15	488,622	3,552,047	350.0	106.7	13.5	4.1	350.0	449.8	75.0	22.9			56.6	7.13
	Recovery Furnace #15 Smelt Dissolving Tank Vent	RF16	IPRF16	488,622	3,552,047	274.0	83.5	6.2	1.9	170.0	349.8	25.0	7.6			23.1	2.91
	Lime Kiln #7 ESP Stack	LK7	IPLK7	488,622	3,552,047	270.0	82.3	6.0	1.8	450.0	505.4	50.0	15.2		45.6	5.75	
	Lime Area	OPG8	IPOPG8	488,622	3,552,047	32.8	10.0	32.8	10.0	32.0	273.2	0.3	0.1	Fugitive est. as pt source	7.9	1.00	
	Power Boiler #13 Stack	PB13	IPPB13	488,622	3,552,047	350.0	106.7	13.3	4.1	350.0	449.8	50.0	15.2		88.5	11.15	
														TOTAL	221.7	27.9	
04-13-051-00076	Colonial terminals, inc. plant 1													Stack Data provided by Georgia EPD 5/6/10			
	Boiler No. 1	B001	CT1B001	489,422	3,550,873	36.0	11.0	2.0	0.6	500.0	533.2	9.0	2.7			4.4	0.56
	Boiler No. 2	B002	CT1B002	489,422	3,550,873	36.0	11.0	3.5	1.1	500.0	533.2	7.5	2.3			10.4	1.31
	Boiler No. 3	B003	CT1B003	489,422	3,550,873										3.2	0.40	
	Boiler No. 4	B004	CT1B004	489,422	3,550,873										3.2	0.40	
	Common stack -Plant 2 boilers		CT1B034	489,422	3,550,873	42.0	12.8	2.0	0.6	475.0	519.3	10.0	3.0		6.3	0.79	
	Dry Bulk Loadout & Reclaim Stack Group (silos)	DB	CT1DB	489,422	3,550,873	10.0	3.0	2.5	0.8	70.0	294.3	30.0	9.1		4.2	0.52	
														TOTAL	25.3	3.2	

^a Pertinent permit, application, tables, Georgia EPD and South Carolina DHEC data used. In some cases, no data were available. Engineering estimates are used when data were not available from other sources. See Table D-3. Estimated stack parameters highlighted in yellow.

TABLE D-3
DETERMINATION OF NO₂ AND PM₁₀ EMISSIONS (LB/HR) INCLUDED IN THE NAAQS ANALYSIS

Emission Unit			Heat Input		Maximum	Emission Limit		PM ₁₀		NOx Emission	Basis	PM ₁₀ Emission	Basis
Permit No	Facility	Unit ID	EU Name	(MMBtu/hr)	Hours of Operation	NOx lb/MMBtu	TPY	lb/MMBtu	TPY	Rate (lb/hr)		Rate (lb/hr)	
04-13-103-00012	Effingham county power llc	AB1 FP1 CTG1 CTG2	Auxiliary Boiler Fuel Preheater GE 7FA Combustion Turbine GE 7FA Combustion Turbine	Natural Gas Natural Gas Natural Gas Natural Gas	17.00 8.75 1,943.50 1,943.50		0.10 0.05 0.013 0.013	-- -- -- --	0.008 -- 0.014 0.014	-- -- -- --	1.67 0.44 25.07 25.07	Application No. 14672 21.60	Application No. 14672 Based on proposed project Permit condition 3.3.4 in permit No. 4911-103-0012-V-03-0
04-13-103-00007	Georgia-pacific consumer products lp												
		BO01 BO02 BO03 CT01 CT02 WHB1 WHB2	Circulating Fluidized Bed Boiler Bubbling Bed Fluidized Bed Boiler Circulating Fluidized Bed Boiler Combustion Turbine No. 1 Combustion Turbine No. 2 Waste Heat Boiler No. 1 Waste Heat Boiler No. 2	No. 2 fuel oil Coal Coal Nat Gas/Fuel Oil Nat Gas/Fuel Oil Nat Gas/Fuel Oil Nat Gas/Fuel Oil	422.0 422.0 422.0 316.6 316.6 85.9 85.9		0.40 0.40 0.40 -- -- -- --	-- -- -- -- -- -- --	0.050 0.050 0.050 0.012 0.012 -- --	-- -- -- -- -- -- --	168.80 168.80 168.80 105.00 	Note: GP provided stack data and NOx emission rates 5/10 Application No. 18915 and Permit No. 2621-103-0007-V-03-0 Permit No. 2621-103-0007-V-03-0 	

TABLE D-3
DETERMINATION OF NO₂ AND PM₁₀ EMISSIONS (LB/HR) INCLUDED IN THE NAAQS ANALYSIS

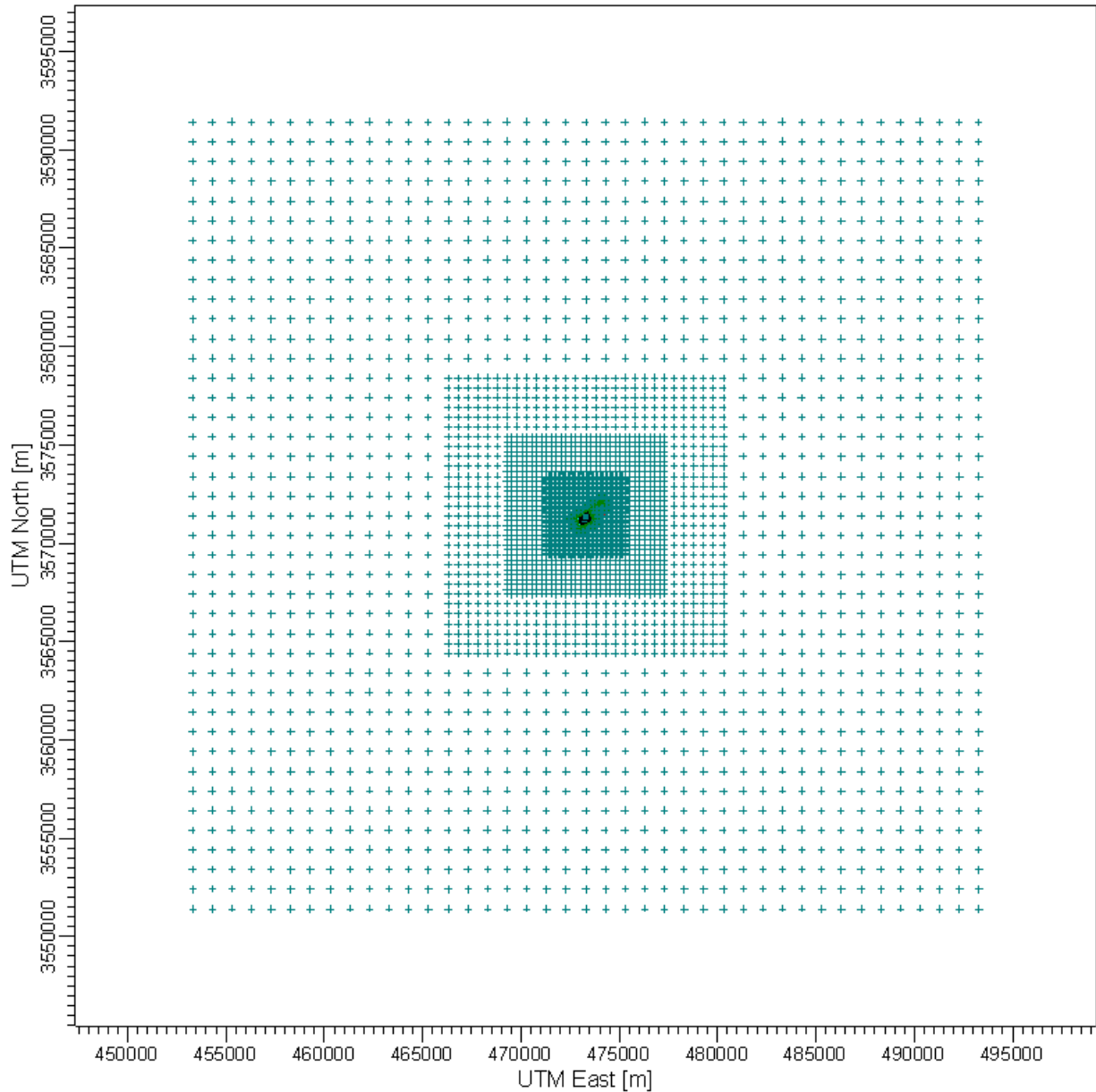
Permit No	Facility	Unit ID	Emission Unit EU Name	Heat Input (MMBtu/hr)	Maximum Hours of Operation	NOx lb/MMBtu	TPY	Emission Limit PM ₁₀ lb/MMBtu	TPY	NOx Emission Rate (lb/hr)	Basis	PM ₁₀ Emission Rate (lb/hr)	Basis
		U161	D Boiler	Coal Fuel oil Natural Gas	338.00 342.00 354.00	0.70 0.30 0.20		0.10	--	236.60 102.60 70.80	Application No. 14967 and Permit No. 2062-051-0110-V-02-0	33.80 34.20 35.40	Application No. 14967
		U163	E Boiler	Natural Gas	25.20	0.27		NA	--	6.92	Table 1.4-1. Emission factor of 280 lb/10 ⁶ scf divided	NA	
		U162	Char Kiln	Natural Gas No. 6 fuel oil	14.00 14.00		4.00	0.01	--	0.91 --	of operation 8,760 hr/yr	0.14	Application No. 14967
04-13-051-00012	Nustar asphalt refining, llc										Permit No.: 2911-051-0012-V-04-0 and AP42 NOx emission factor for Small Boilers (uncontrolled) of 100 lb/10 ⁶ scf		Permit No.: 2911-051-0012-V-04-0. PM is obtained using P = 0.7*(10 / R) ^{0.202} where R equals heat input rate in million BTU per hour and P equals the allowable emission rate in pounds per million BTU
		B004	No. 4 Boiler	Natural Gas/No. 6 Fuel Oil	52.8	0.10		0.50	--	5.18		26.42	
		B005	No. 5 Boiler	Natural Gas/No. 6 Fuel Oil	59.4	0.10		0.49	--	5.82		29.01	
		F001	No. 1 Unit Fired Heater	Natural Gas/No. 6 Fuel Oil	56.4			0.21	--			11.87	Permit No.: 2911-051-0012-V-04-0. PM is obtained using P = 0.5 * (10 / R) ^{0.5} where R equals heat input rate in million BTU per hour and P equals the allowable emission rate in pounds per million BTU
		F002	No. 2 Unit Fired Heater	Natural Gas/No. 6 Fuel Oil	56.4			0.21	--			11.87	
		D001	Crude Oil Distillation Tower No. 1										
		D002	Crude Oil Distillation Tower No. 2										
		H001	Hot Oil Heater	Natural Gas/No. 6 Fuel Oil	15.0		9.24	0.010	--			0.15	
04-13-051-00007	International Paper - Savannah	RF15	Recovery Furnace #15 Stack	Natural Gas Black Liquor	1,620 1,950	8,760	823.44			188.00	Application No. 16986. Assumed maximum hours of operation 8,760 hr/yr	56.6	Application No. 16986
		RF10	Recovery Furnace #15 Smelt Dissolving Tank Vent			8,760	22.00			5.02	Application No. 16107. Assumed maximum hours of operation 8,760 hr/yr	23.1	Permit No. 2631-051-0007-V-02-0
		LK07	Lime Kiln #7 ESP Stack	Combination of fuels	147	8,760	265.00			60.50	Application No. 16986. Assumed maximum hours of operation 8,760 hr/yr	45.6	Application No. 16986
		OPG8	Lime Area							7.9			
		PB13	Power Boiler #13 Stack	Coal No. 6 Fuel Oil/Used Oil Woodwaste	1,179 932 510	0.70 0.30 0.30		0.075		825.58 279.57 153.00	Application No. 16986	88.5 69.9 38.3	
04-13-051-00148	Arizona chemical corp.	TB01/EU 097	SB-1T Top Temporary Boiler	Natural Gas	40	720	0.10	--		3.92	Permit No. 2821-051-0148-V-02-0 and AP42 NOx emission factor for Small Boilers (uncontrolled) of Permit No. 2821-051-0148-V-02-0 and AP42 NOx emission factor for Small Boilers (uncontrolled) of Permit No. 2821-051-0148-V-02-0 and Application No. 17166.		
		TB02/EU 052	S/B 7T Temporary Packaged Steam Boiler	Natural Gas	99	720	0.10	--		9.71			
		E101	Steam Boiler	Natural Gas	140		37.00	--		27.90			
04-13-051-00076	Colonial terminals, inc. plant 1												
		B001	Boiler No. 1	No. 6 fuel Oil	6	--		0.70				4.4	Permit No. 5171-051-0076-V-02-0 and Application No. 17037
		B002	Boiler No. 2	No. 6 fuel Oil	16	--		0.63				10.4	Permit No. 5171-051-0076-V-02-0 and Application No. 17037. PM equation for Boiler No. 2 is P = 0.7(10/R) ^{0.202} , where P equals allowable and R is the comined heat input in MMBtu/hr.
		B003	Boiler No. 3	No. 6 fuel Oil	6	--		0.50				3.2	Permit No. 5171-051-0076-V-02-0 and Application No. 17037
		B004	Boiler No. 4	No. 6 fuel Oil	6	--		0.50				3.2	Permit No. 5171-051-0076-V-02-0 and Application No. 17037
		DB	Dry Bulk Loadout & Reclaim Stack Group	Material Input of dry bulk products (silos 1-40)	1,000	--					Uncontrolled Controlled with baghouses	419.55 4.15	Permit No. 5171-051-0076-V-02-0 and Application No. 17037. PM equation for Boiler No. 2 is E = 4.1P ^{0.67} , where E equals emission rate in pounds per hour and P is the process input weight rate. 99% control

Sources =
Applications were obtained from the Georgia Title V permit applications website.

APPENDIX E
RECEPTOR GRIDS

PROJECT TITLE:

**FIGURE E-1
20 KM RECEPTOR GRID**

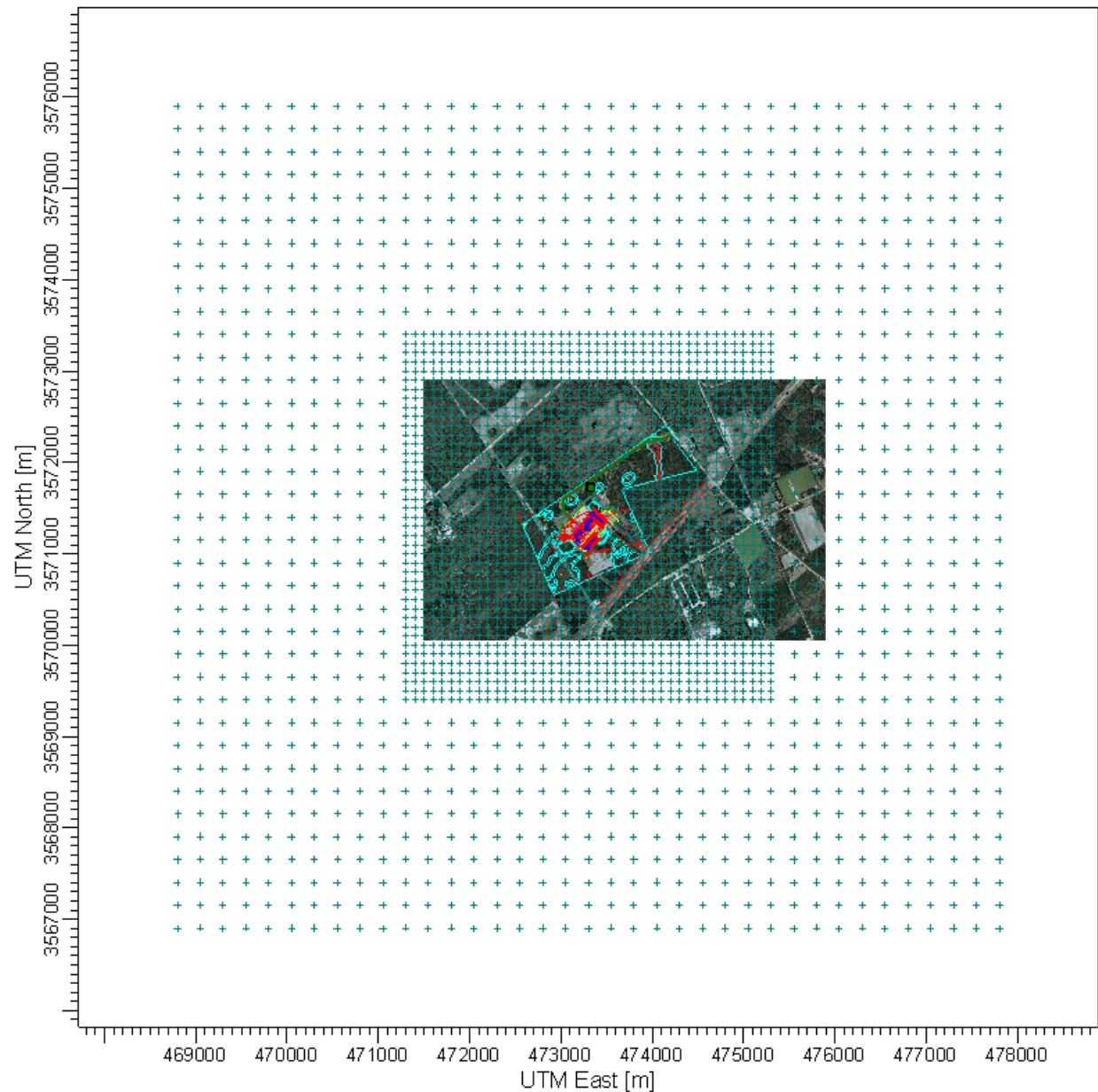


COMMENTS:	SOURCES:	COMPANY NAME:	
	14	GOLDER ASSOCIATES INC.	
	RECEPTORS:	MODELER:	
	4469		
		SCALE: 1:326,262	
		0 10 km	
		DATE:	PROJECT NO.:
		6/14/2010	103-87522

PROJECT TITLE:

FIGURE E-2

4.5 KM RECEPTOR GRID FOR NO2 NAAQS ANALYSIS



COMMENTS:

SOURCES:

28

COMPANY NAME:

GOLDER ASSOCIATES INC.

RECEPTORS:

2741

MODELER:

SCALE:

1:70,160

0

2 km

DATE:

6/14/2010

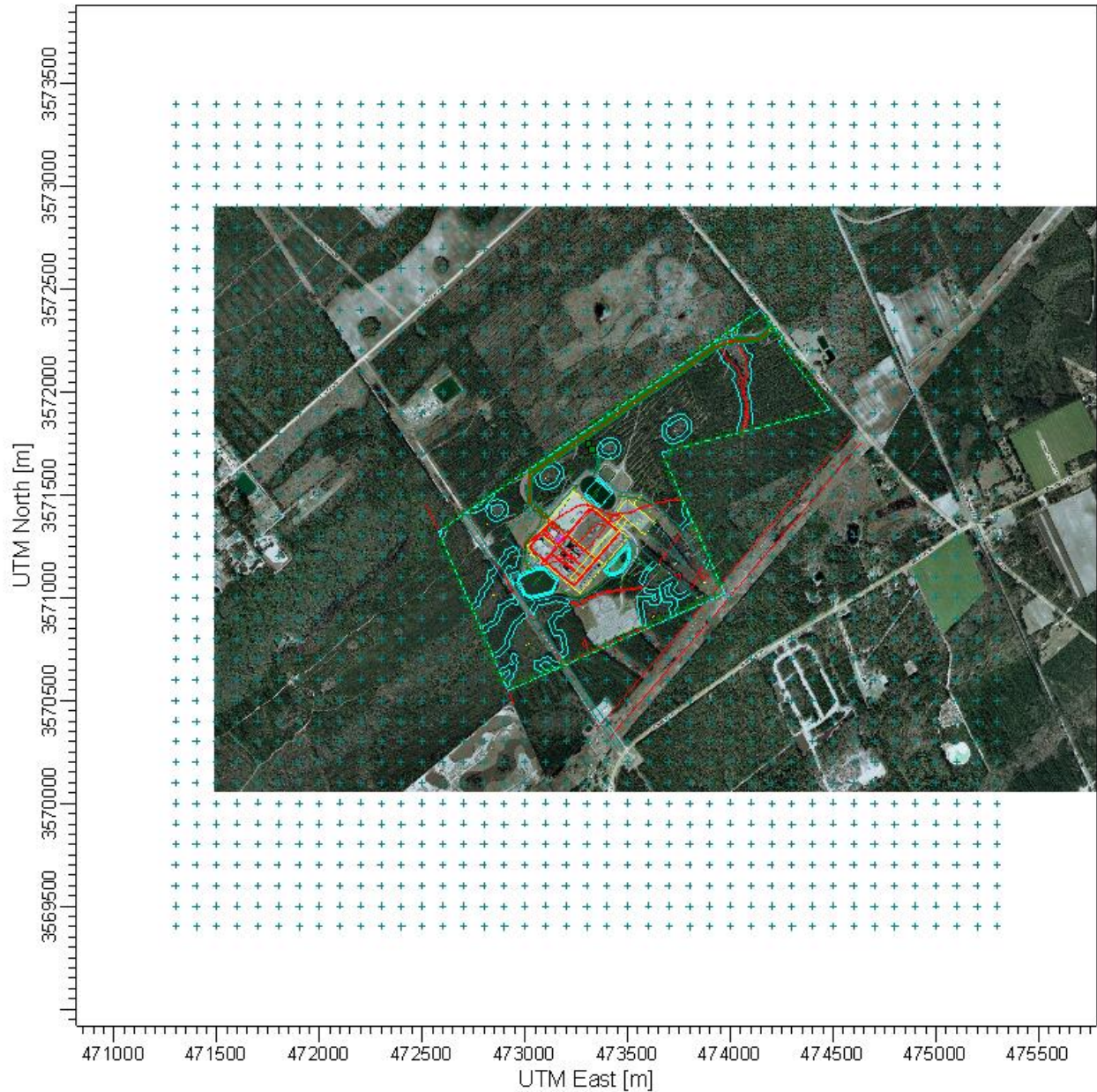
PROJECT NO.:

103-87522

PROJECT TITLE:

FIGURE E-3

2 KM RECEPTOR GRID FOR THE PM_{2.5} NAAQS ANALYSIS



COMMENTS:

SOURCES:

28

COMPANY NAME:

GOLDER ASSOCIATES INC.

RECEPTORS:

1661

MODELER:

SCALE:

1:31,206

0

1 km

DATE:

6/14/2010

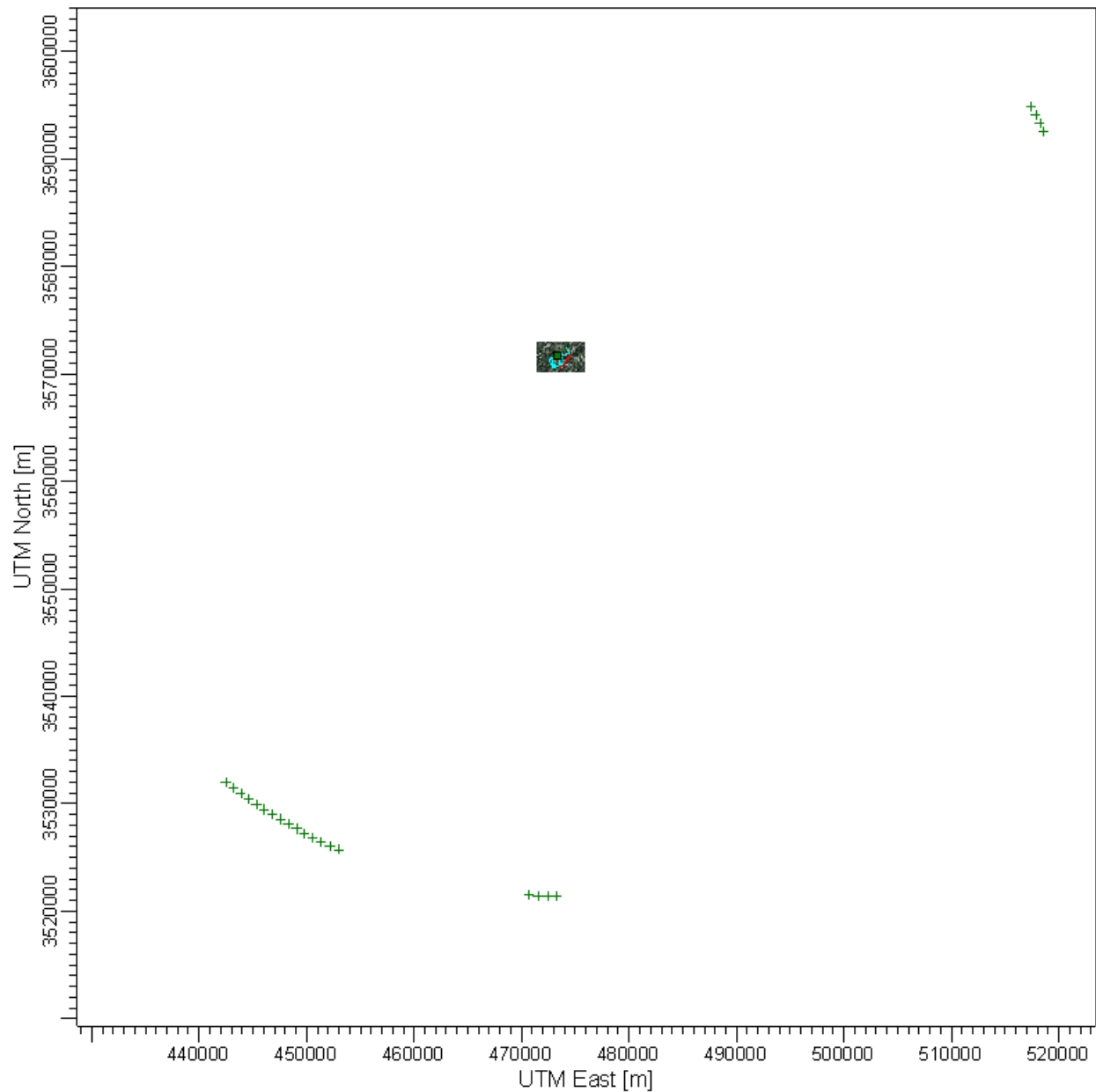
PROJECT NO.:

103-87522

PROJECT TITLE:

FIGURE E-4

RECEPTOR GRID FOR THE PSD CLASS I AREAS



COMMENTS:

SOURCES:

28

COMPANY NAME:

GOLDER ASSOCIATES INC.

RECEPTORS:

2484

MODELER:

SCALE:

1:595 631

0



20 km

DATE:

6/14/2010

PROJECT NO.:

103-87522

ATTACHMENT B
ACID RAIN FORMS



Acid Rain Permit Application

For more information, see instructions and 40 CFR 72.30 and 72.31.

This submission is: ☐ new ☒ revised for ☐ Acid Rain permit renewal

STEP 1

Identify the facility name, State, and plant (ORIS) code.

Effingham County Power Facility (Source) Name	GA State	55406 Plant Code
---	--------------------	----------------------------

STEP 2

Enter the unit ID# for every affected unit at the affected source in column "a."

a	b
Unit ID#	Unit Will Hold Allowances in Accordance with 40 CFR 72.9(c)(1)
1	Yes
2	Yes
3	Yes
4	Yes

Permit Requirements

STEP 3

Read the standard requirements.

- (1) The designated representative of each affected source and each affected unit at the source shall:
 - (i) Submit a complete Acid Rain permit application (including a compliance plan) under 40 CFR part 72 in accordance with the deadlines specified in 40 CFR 72.30; and
 - (ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review an Acid Rain permit application and issue or deny an Acid Rain permit;
- (2) The owners and operators of each affected source and each affected unit at the source shall:
 - (i) Operate the unit in compliance with a complete Acid Rain permit application or a superseding Acid Rain permit issued by the permitting authority; and
 - (ii) Have an Acid Rain Permit.

Monitoring Requirements

- (1) The owners and operators and, to the extent applicable, designated representative of each affected source and each affected unit at the source shall comply with the monitoring requirements as provided in 40 CFR part 75.
- (2) The emissions measurements recorded and reported in accordance with 40 CFR part 75 shall be used to determine compliance by the source or unit, as appropriate, with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.
- (3) The requirements of 40 CFR part 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements of the Act and other provisions of the operating permit for the source.

Sulfur Dioxide Requirements

- (1) The owners and operators of each source and each affected unit at the source shall:
 - (i) Hold allowances, as of the allowance transfer deadline, in the source's compliance account (after deductions under 40 CFR 73.34(c)), not less than the total annual emissions of sulfur dioxide for the previous calendar year from the affected units at the source; and
 - (ii) Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.
- (2) Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act.
- (3) An affected unit shall be subject to the requirements under paragraph (1) of the sulfur dioxide requirements as follows:
 - (i) Starting January 1, 2000, an affected unit under 40 CFR 72.6(a)(2); or
 - (ii) Starting on the later of January 1, 2000 or the deadline for monitor certification under 40 CFR part 75, an affected unit under 40 CFR

72.6(a)(3).

Sulfur Dioxide Requirements, Cont'd.

STEP 3, Cont'd.

(4) Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.

(5) An allowance shall not be deducted in order to comply with the requirements under paragraph (1) of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.

(6) An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.

(7) An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

Nitrogen Oxides Requirements

The owners and operators of the source and each affected unit at the source shall comply with the applicable Acid Rain emissions limitation for nitrogen oxides.

Excess Emissions Requirements

(1) The designated representative of an affected source that has excess emissions in any calendar year shall submit a proposed offset plan, as required under 40 CFR part 77.

(2) The owners and operators of an affected source that has excess emissions in any calendar year shall:

(i) Pay without demand the penalty required, and pay upon demand the interest on that penalty, as required by 40 CFR part 77; and

(ii) Comply with the terms of an approved offset plan, as required by 40 CFR part 77.

Recordkeeping and Reporting Requirements

(1) Unless otherwise provided, the owners and operators of the source and each affected unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the Administrator or permitting authority:

(i) The certificate of representation for the designated representative for the source and each affected unit at the source and all documents that

Effingham County Power Facility (Source) Name (from STEP 1)

demonstrate the truth of the statements in the certificate of representation, in accordance with 40 CFR 72.24; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative;

STEP 3, Cont'd.

Recordkeeping and Reporting Requirements, Cont'd.

- (ii) All emissions monitoring information, in accordance with 40 CFR part 75, provided that to the extent that 40 CFR part 75 provides for a 3-year period for recordkeeping, the 3-year period shall apply.
 - (iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,
 - (iv) Copies of all documents used to complete an Acid Rain permit application and any other submission under the Acid Rain Program or to demonstrate compliance with the requirements of the Acid Rain Program.
- (2) The designated representative of an affected source and each affected unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR part 72 subpart I and 40 CFR part 75.

Liability

- (1) Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to section 113(c) of the Act.
- (2) Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to section 113(c) of the Act and 18 U.S.C. 1001.
- (3) No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.
- (4) Each affected source and each affected unit shall meet the requirements of the Acid Rain Program.
- (5) Any provision of the Acid Rain Program that applies to an affected source (including a provision applicable to the designated representative of an affected source) shall also apply to the owners and operators of such source and of the affected units at the source.
- (6) Any provision of the Acid Rain Program that applies to an affected unit (including a provision applicable to the designated representative of an affected unit) shall also apply to the owners and operators of such unit.
- (7) Each violation of a provision of 40 CFR parts 72, 73, 74, 75, 76, 77, and 78 by an affected source or affected unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Act.

Facility (Source) Name (from STEP 1)

Effect on Other Authorities, Cont'd.**STEP 3, Cont'd.**

to applicable National Ambient Air Quality Standards or State Implementation Plans;

(2) Limiting the number of allowances a source can hold; *provided*, that the number of allowances held by the source shall not affect the source's obligation to comply with any other provisions of the Act;

(3) Requiring a change of any kind in any State law regulating electric utility rates and charges, affecting any State law regarding such State regulation, or limiting such State regulation, including any prudence review requirements under such State law;

(4) Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or,

(5) Interfering with or impairing any program for competitive bidding for power supply in a State in which such program is established.

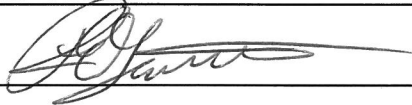
Certification**STEP 4**

Read the certification statement, sign, and date.

I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name **R. Eric Garrett**

Signature



Date

7/22/10

ATTACHMENT C
CERTIFICATE OF REPRESENTATION



Certificate of Representation

Page 1

For more information, see instructions and 40 CFR 72.24; 40 CFR 96.113, 96.213, or 96.313, or a comparable state regulation under the Clean Air Interstate Rule (CAIR) NO_x Annual, SO₂, and NO_x Ozone Season Trading Programs or 40 CFR 97.113, 97.213, or 97.313.

FACILITY (SOURCE) INFORMATION

This submission is: ☐ New ☒ Revised (revised submissions must be complete; see instructions)

STEP 1 Provide information for the facility (source).

Facility (Source) Name	Effingham County Power	State	GA	Plant Code	55406
County Name					
Effingham					
Latitude			32° 16' 43"		
Longitude			81° 17' 01"		

STEP 2 Enter requested information for the designated representative.

Name	R. Eric Garrett	Title	General Manager
Company Name			
CAMS			
Address			
3440 McCall Road Rincon, GA 31326			
Phone Number		(912) 826-3287	
Fax Number		(912) 826-3203	
E-mail address			
egarrett@camsops.com			

STEP 3 Enter requested information for the alternate designated representative.

Name	Matt Lydon	Title	EHS Manager
Company Name			
CAMS			
Address			
3440 McCall Road Rincon, GA 31326			
Phone Number		(912) 826-3277	
Fax Number		(912) 826-3203	
E-mail address			
mlydon@camsops.com			

Facility (Source) Name (from Step 1) **Effingham County Power**

UNIT INFORMATION

STEP 4: Complete one page for each unit located at the facility identified in STEP 1 (i.e., for each boiler, simple cycle combustion turbine, or combined cycle combustion turbine) Do not list duct burners. Indicate each program to which the unit is subject, and enter all other unit-specific information, including the name of each owner and operator of the unit and the generator ID number and nameplate capacity of each generator served by the unit. If the unit is subject to a program, then the facility (source) is also subject. (For units subject to the NO_x Budget Trading Program, a separate "Account Certificate of Representation" form must be submitted to meet requirements under that program.)

Applicable Program(s): ☒ Acid Rain ☒ CAIR NO_x Annual ☒ CAIR SO₂ ☐ CAIR NO_x Ozone Season

Unit ID# 1	Unit Type CC	Source Category Electric Utility	Generator ID Number (Maximum 8 characters)	Acid Rain Nameplate Capacity (MWe)	CAIR Nameplate Capacity (MWe)
		NAICS Code 221112	UNT1	197	197
Date unit began (or will begin) serving any generator producing electricity for sale (including test generation) (mm/dd/yyyy): 02/04/2003		Check One: Actual <input checked="" type="checkbox"/> Projected <input type="checkbox"/>			
Company Name: Effingham County Power, LLC (operator services are contracted to a third party provider)			<input checked="" type="checkbox"/> Owner <input checked="" type="checkbox"/> Operator		
Company Name:			<input type="checkbox"/> Owner <input type="checkbox"/> Operator		
Company Name:			<input type="checkbox"/> Owner <input type="checkbox"/> Operator		
Company Name:			<input type="checkbox"/> Owner <input type="checkbox"/> Operator		
Company Name:			<input type="checkbox"/> Owner <input type="checkbox"/> Operator		

Facility (Source) Name (from Step 1) **Effingham County Power**

UNIT INFORMATION

STEP 4: Complete one page for each unit located at the facility identified in STEP 1 (i.e., for each boiler, simple cycle combustion turbine, or combined cycle combustion turbine) Do not list duct burners. Indicate each program to which the unit is subject, and enter all other unit-specific information, including the name of each owner and operator of the unit and the generator ID number and nameplate capacity of each generator served by the unit. If the unit is subject to a program, then the facility (source) is also subject. (For units subject to the NO_x Budget Trading Program, a separate "Account Certificate of Representation" form must be submitted to meet requirements under that program.)

Applicable Program(s): ☒ Acid Rain ☒ CAIR NO_x Annual ☒ CAIR SO₂ ☐ CAIR NO_x Ozone Season

Unit ID# 2	Unit Type CC	Source Category Electric Utility	Generator ID Number (Maximum 8 characters)	Acid Rain Nameplate Capacity (MWe)	CAIR Nameplate Capacity (MWe)
		NAICS Code 221112	UNT2	197	197
Date unit began (or will begin) serving any generator producing electricity for sale (including test generation) (mm/dd/yyyy): 02/08/2003		Check One: Actual <input checked="" type="checkbox"/> Projected <input type="checkbox"/>			
Company Name: Effingham County Power, LLC (operator services are contracted to a third party provider)			<input checked="" type="checkbox"/> Owner <input checked="" type="checkbox"/> Operator		
Company Name:			<input type="checkbox"/> Owner <input type="checkbox"/> Operator		
Company Name:			<input type="checkbox"/> Owner <input type="checkbox"/> Operator		
Company Name:			<input type="checkbox"/> Owner <input type="checkbox"/> Operator		
Company Name:			<input type="checkbox"/> Owner <input type="checkbox"/> Operator		

Facility (Source) Name (from Step 1) **Effingham County Power**

UNIT INFORMATION

STEP 4: Complete one page for each unit located at the facility identified in STEP 1 (i.e., for each boiler, simple cycle combustion turbine, or combined cycle combustion turbine) Do not list duct burners. Indicate each program to which the unit is subject, and enter all other unit-specific information, including the name of each owner and operator of the unit and the generator ID number and nameplate capacity of each generator served by the unit. If the unit is subject to a program, then the facility (source) is also subject. (For units subject to the NO_x Budget Trading Program, a separate "Account Certificate of Representation" form must be submitted to meet requirements under that program.)

Applicable Program(s): ☒ Acid Rain ☒ CAIR NO_x Annual ☒ CAIR SO₂ ☐ CAIR NO_x Ozone Season

Unit ID# 3	Unit Type CC	Source Category Electric Utility	Generator ID Number (Maximum 8 characters)	Acid Rain Nameplate Capacity (MWe)	CAIR Nameplate Capacity (MWe)
		NAICS Code 221112	UNT3	197	197
Date unit began (or will begin) serving any generator producing electricity for sale (including test generation) (mm/dd/yyyy): Projected 06/01/2014		Check One: Actual <input type="checkbox"/> Projected <input checked="" type="checkbox"/>			
Company Name: Effingham County Power, LLC (operator services are contracted to a third party provider)			<input checked="" type="checkbox"/> Owner <input checked="" type="checkbox"/> Operator		
Company Name:			<input type="checkbox"/> Owner <input type="checkbox"/> Operator		
Company Name:			<input type="checkbox"/> Owner <input type="checkbox"/> Operator		
Company Name:			<input type="checkbox"/> Owner <input type="checkbox"/> Operator		
Company Name:			<input type="checkbox"/> Owner <input type="checkbox"/> Operator		

Facility (Source) Name (from Step 1) **Effingham County Power**

UNIT INFORMATION

STEP 4: Complete one page for each unit located at the facility identified in STEP 1 (i.e., for each boiler, simple cycle combustion turbine, or combined cycle combustion turbine) Do not list duct burners. Indicate each program to which the unit is subject, and enter all other unit-specific information, including the name of each owner and operator of the unit and the generator ID number and nameplate capacity of each generator served by the unit. If the unit is subject to a program, then the facility (source) is also subject. (For units subject to the NO_x Budget Trading Program, a separate "Account Certificate of Representation" form must be submitted to meet requirements under that program.)

Applicable Program(s): ☒ Acid Rain ☒ CAIR NO_x Annual ☒ CAIR SO₂ ☐ CAIR NO_x Ozone Season

Unit ID# 4	Unit Type CC	Source Category Electric Utility	Generator ID Number (Maximum 8 characters)	Acid Rain Nameplate Capacity (MWe)	CAIR Nameplate Capacity (MWe)
		NAICS Code 221112	UNT4	197	197
Date unit began (or will begin) serving any generator producing electricity for sale (including test generation) (mm/dd/yyyy): Projected 06/01/2014		Check One: Actual <input type="checkbox"/> Projected <input checked="" type="checkbox"/>			
Company Name: Effingham County Power, LLC (operator services are contracted to a third party provider)			<input checked="" type="checkbox"/> Owner <input checked="" type="checkbox"/> Operator		
Company Name:			<input type="checkbox"/> Owner <input type="checkbox"/> Operator		
Company Name:			<input type="checkbox"/> Owner <input type="checkbox"/> Operator		
Company Name:			<input type="checkbox"/> Owner <input type="checkbox"/> Operator		
Company Name:			<input type="checkbox"/> Owner <input type="checkbox"/> Operator		

Facility (Source) Name (from Step 1) Effingham County Power
--

STEP 5: Read the appropriate certification statements, sign, and date.

Acid Rain Program

I certify that I was selected as the designated representative or alternate designated representative (as applicable) by an agreement binding on the owners and operators of the affected source and each affected unit at the source (i.e., the source and each unit subject to the Acid Rain Program, as indicated in "Applicable Program(s)" in Step 4).

I certify that I have all necessary authority to carry out my duties and responsibilities under the Acid Rain Program on behalf of the owners and operators of the affected source and each affected unit at the source and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions.

I certify that the owners and operators of the affected source and each affected unit at the source shall be bound by any order issued to me by the Administrator, the permitting authority, or a court regarding the source or unit.

Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, an affected unit, or where a utility or industrial customer purchases power from an affected unit under a life-of-the-unit, firm power contractual arrangement, I certify that:

I have given a written notice of my selection as the designated representative or alternate designated representative (as applicable) and of the agreement by which I was selected to each owner and operator of the affected source and each affected unit at the source; and

Allowances, and proceeds of transactions involving allowances, will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement, except that, if such multiple holders have expressly provided for a different distribution of allowances, allowances and proceeds of transactions involving allowances will be deemed to be held or distributed in accordance with the contract.

Clean Air Interstate Rule (CAIR) NO_x Annual Trading Program

I certify that I was selected as the CAIR designated representative or alternate CAIR designated representative (as applicable), by an agreement binding on the owners and operators of the CAIR NO_x source and each CAIR NO_x unit at the source (i.e., the source and each unit subject to the CAIR NO_x Annual Trading Program, as indicated in "Applicable Program(s)" in Step 4).

I certify that I have all necessary authority to carry out my duties and responsibilities under the CAIR NO_x Annual Trading Program on behalf of the owners and operators of the CAIR NO_x source and each CAIR NO_x unit at the source and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions.

I certify that the owners and operators of the CAIR NO_x source and each CAIR NO_x unit at the source shall be bound by any order issued to me by the Administrator, the permitting authority, or a court regarding the source or unit.

Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, a CAIR NO_x unit, or where a utility or industrial customer purchases power from a CAIR NO_x unit under a life-of-the-unit, firm power contractual arrangement, I certify that:

I have given a written notice of my selection as the CAIR designated representative or alternate CAIR designated representative (as applicable) and of the agreement by which I was selected to each owner and operator of the CAIR NO_x source and each CAIR NO_x unit at the source; and

CAIR NO_x allowances and proceeds of transactions involving CAIR NO_x allowances will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement, except that, if such multiple holders have expressly provided for a different distribution of CAIR NO_x allowances by contract, CAIR NO_x allowances and proceeds of transactions involving CAIR NO_x allowances will be deemed to be held or distributed in accordance with the contract.

Facility (Source) Name (from Step 1)	Effingham County Power
--------------------------------------	------------------------

Clean Air Interstate Rule (CAIR) SO₂ Trading Program

I certify that I was selected as the CAIR designated representative or alternate CAIR designated representative (as applicable), by an agreement binding on the owners and operators of the CAIR SO₂ source and each CAIR SO₂ unit at the source (i.e., the source and each unit subject to the SO₂ Trading Program, as indicated in "Applicable Program(s)" in Step 4).

I certify that I have all necessary authority to carry out my duties and responsibilities under the CAIR SO₂ Trading Program, on behalf of the owners and operators of the CAIR SO₂ source and each CAIR SO₂ unit at the source and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions.

I certify that the owners and operators of the CAIR SO₂ source and each CAIR SO₂ unit at the source shall be bound by any order issued to me by the Administrator, the permitting authority, or a court regarding the source or unit.

Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, a CAIR SO₂ unit, or where a utility or industrial customer purchases power from a CAIR SO₂ unit under a life-of-the-unit, firm power contractual arrangement, I certify that:

I have given a written notice of my selection as the CAIR designated representative or alternate CAIR designated representative (as applicable) and of the agreement by which I was selected to each owner and operator of the CAIR SO₂ source and each CAIR SO₂ unit at the source; and

CAIR SO₂ allowances and proceeds of transactions involving CAIR SO₂ allowances will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement, except that, if such multiple holders have expressly provided for a different distribution of CAIR SO₂ allowances by contract, CAIR SO₂ allowances and proceeds of transactions involving CAIR SO₂ allowances will be deemed to be held or distributed in accordance with the contract.

Clean Air Interstate Rule (CAIR) NO_x Ozone Season Trading Program

I certify that I was selected as the CAIR designated representative or alternate CAIR designated representative (as applicable), by an agreement binding on the owners and operators of the CAIR NO_x Ozone Season source and each CAIR NO_x Ozone Season unit at the source (i.e., the source and each unit subject to the CAIR NO_x Ozone Season Trading Program, as indicated in "Applicable Program(s)" in Step 4).

I certify that I have all necessary authority to carry out my duties and responsibilities under the CAIR NO_x Ozone Season Trading Program on behalf of the owners and operators of the CAIR NO_x Ozone Season source and each CAIR NO_x Ozone Season unit at the source and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions.

I certify that the owners and operators of the CAIR NO_x Ozone Season source and each CAIR NO_x Ozone Season unit shall be bound by any order issued to me by the Administrator, the permitting authority, or a court regarding the source or unit.

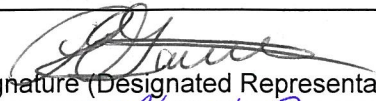

Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, a CAIR NO_x Ozone Season unit, or where a utility or industrial customer purchases power from a CAIR NO_x Ozone Season unit under a life-of-the-unit, firm power contractual arrangement, I certify that:

I have given a written notice of my selection as the CAIR designated representative or alternate CAIR designated representative (as applicable) and of the agreement by which I was selected to each owner and operator of the CAIR NO_x Ozone Season source and each CAIR NO_x Ozone Season unit; and

CAIR NO_x Ozone Season allowances and proceeds of transactions involving CAIR NO_x Ozone Season allowances will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement, except that, if such multiple holders have expressly provided for a different distribution of CAIR NO_x Ozone Season allowances by contract, CAIR NO_x Ozone Season allowances and proceeds of transactions involving CAIR NO_x Ozone Season allowances will be deemed to be held or distributed in accordance with the contract.

Facility (Source) Name (from Step 1) **Effingham County Power**General

I am authorized to make this submission on behalf of the owners and operators of the source or units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

 Signature (Designated Representative)	Date 7/22/10
 Signature (Alternate Designated Representative)	Date 7/22/2010