NORTH CAROLINA DIVISION OF AIR QUALITY # Air Permit Review and PSD Preliminary Determination Permit Issue Date:	Region: Winston-Salem Regional Office County: Rockingham NC Facility ID: 7900182 Inspector's Name: NA Date of Last Inspection: NA Compliance Code: NA
Facility Data **Applicant (Facility's Name):** NTE Carolinas II, LLC - Reidsville Energy Center **Facility Address**: NTE Carolinas II, LLC - Reidsville Energy Center 4563 NC Highway 65 Reidsville, NC 27320 SIC: 4911 / Electric Services NAICS: 221112 / Fossil Fuel Electric Power Generation **Facility Classification: Before**: NA After: Title V **Fee Classification: Before**: NA After: Title V	**Permit Applicability (this application only)** SIP: 02D .0503, .0516, 0521, 0524, .0530, .1111 02Q .0402 NSPS: KKKK, TTTT, Dc, IIII NESHAP: ZZZZ PSD: YES PSD Avoidance: NA NC Toxics: YES 112(r): No Other:

Contact Data

Facility Contact	**Authorized Contact**	**Technical Contact**
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Application Data

Application Number: 7900182.16A
Date Received: 04/15/2016
Application Type: Greenfield Facility
Application Schedule: PSD
Existing Permit Data
Existing Permit Number: NA
Existing Permit Issue Date: NA
Existing Permit Expiration Date: NA

Total Actual emissions in TONS/YEAR:

CY	SO2	NOX	VOC	CO	PM10	Total HAP	Largest HAP

<No Inventory>

Review Engineer: Joseph Voelker **Review Engineer's Signature:** **Date:**	**Comments / Recommendations**: **Issue**: 10494 R00 **Permit Issue Date**: MM/DD/YYYY **Permit Expiration Date**: MM/DD/YYYY

Table of Contents

1. Introduction and Purpose of Application

NTE Energy Carolinas, II LLC (NTE) is proposing to construct and operate a nominal 500 MW natural gas-fired combined cycle power plant near the city of Reidsville in Rockingham County, North Carolina. The facility, which will be known as the Reidsville Energy Center (REC), will be very similar to the Kings Mountain Energy Center which was previously permitted in 2015.

The project will consist of a single power block in a “1x1” combined cycle multi-shaft configuration, including a combustion turbine (CT) and heat recovery steam generator (HRSG) with a steam turbine (ST). The CT and ST will each have separate electric generators. As discussed with the NCDAQ at the pre-application meeting on March 11, 2016, NTE is currently evaluating two combustion turbine options and will make a commercial decision at a later date. Thus, NTE is requesting an Air Quality Permit to Construct/Operate for one of the following equipment configurations:

- Mitsubishi Hitachi Power Systems Americas, Inc. (MHPSA) M501 GAC CT in a 1x1 combined cycle configuration, or
- Siemens Energy, Inc. (Siemens) SCC6-8000H CT in a 1x1 combined cycle configuration

The required demonstrations in the air permit application, including regulatory compliance demonstrations and air quality modeling analyses, are performed to evaluate both of these configurations.

A duct burner (DB) will be installed in the heat recovery steam generator (HRSG) of the proposed new unit. The CT and DB will fire “pipeline-quality” natural gas which NTE plans to obtain from pipelines, owned by Transcontinental Gas Pipe Line Company, LLC, which cross the site. The HRSG will be equipped with selective catalytic reduction (SCR) to minimize nitrogen oxide (NO_X) emissions and an oxidation catalyst to minimize carbon monoxide (CO) and volatile organic compound (VOC) emissions from the CT and DB.

The project will also include the balance of the plant equipment which will be identical for either combustion turbine option. This equipment includes the following:

- One steam turbine (not an emission source)
- One natural gas-fired auxiliary boiler
- One natural gas-fired fuel gas heater
- One CT inlet evaporative cooler (not an emission source)
- Multiple cell mechanical draft, counter flow, evaporative cooling tower system
- One emergency diesel generator
- One diesel fire pump
- Diesel fuel, lubricating oil, and aqueous ammonia storage tanks

The proposed facility will be a major source of multiple criteria air pollutants and will be subject to the requirements of the Prevention of Significant Deterioration (PSD) regulations.

2 Project Emissions

The emissions calculation procedures used to quantify potential emissions from the project are based on CT performance and emissions data provided by MHPSA and Siemens for the CT/HRSG configuration under consideration, other equipment vendor data, engineering estimates, emission limitations specified in applicable New Source Performance Standards and National Emissions Standards for Hazardous Air Pollutants, emission factors documented in U.S. Environmental Protection Agency's (EPA) "Compilation of Air Pollution Emission Factors, AP-42" and proposed BACT emission limits.

In order to develop reasonable, yet conservatively high, estimates of maximum potential emissions from the project, three potential operating scenarios were evaluated, encompassing the expected range of operating assumptions and numbers of startups and shutdowns. The three cases evaluated are:

- Case A - Mid-range dispatch (approximately 5 days per week, 16 hours per day, 52 weeks per year - total of 270 startups/shutdowns)
- Case B - Base load (approximately 6 days per week, 24 hours per day, 52 weeks per year - total of 80 startups/shutdowns)

- Case C – Continuous operation (8,760 hours of continuous base load operation)

Within each scenario, different assumptions were made for the numbers/types of startups/shutdowns and hours of base load operation. The number of normal operating hours and number of startups/shutdowns in each scenario were multiplied by the emissions rate for the representative CT operating mode. The steady state operating mode emissions were based on average annual ambient conditions. The maximum emissions from all operating scenarios were calculated and are proposed to establish annual emissions limits from the CT and DB. The results of these calculations are presented in Tables 3-6 and 3-7 of the application for both turbine options and detailed assumptions are provided in Appendix B of the application.

Tables 3-14 (MHPSA) and 3-15 (Siemens) from the permit application represent the Project's total potential emissions and are reproduced below. The calculations of emissions are presented thoroughly in the application and will not be presented in full detail here. A few items are worth highlighting however.

- With the exception of the combustion turbines all emission sources emit relatively small amounts of pollutants. Only the auxiliary boiler emits more than the "insignificant activity based on size or production rate" of 5 tpy of a regulated criteria pollutant (7.18 tpy of NOx) pursuant to 15A NCAC 02Q .0503(8).
- A PSD review is triggered for a number of pollutants. Combined-cycle CTs with HRSGs are considered as fossil fuel-fired steam electric plants. Therefore, the applicable PSD threshold for the Project is 100 TPY of potential emissions. Once it is determined that a pollutant exceeds the major source threshold, each of the remaining pollutants is subject to PSD review if the potential to emit (PTE) exceeds its Significant Emission Rate (SER). Therefore, the Project pollutants subject to PSD review are NOx, CO, VOC, PM10, PM2.5, H_2SO_4 and GHG. The requirements of PSD will be discussed elsewhere in this review.

Table 3-14 Total Project Maximum Potential Annual Emissions/MHPSA (tons/year)

Emission Unit	**NO_X**	**CO**	**VOC**	**SO_2**	**PM**	**PM_{10}**	**$PM_{2.5}$**	**H_2SO_4**	**Lead**	**GHGs (CO_{2e})**	**Total HAPs**
Combustion Turbine *w/*Duct Burner	119.14	280.26	100.37	31.27	82.34	82.34	82.34	30.27	---	1,757,319	11.40
Diesel Engine-Powered Emergency Generator	4.34	0.73	0.08	0.005	0.04	0.04	0.04	0.0007	0.000027	486	0.006
Diesel Engine-Powered Fire Pump	0.45	0.07	0.02	0.0008	0.01	0.01	0.01	0.00012	0.0000048	86	0.002
Auxiliary Boiler	1.94	7.18	0.98	0.41	1.37	1.37	1.37	0.07	0.000096	22,830	0.36
Fuel Gas Heater	0.48	1.45	0.13	0.09	0.26	0.26	0.26	0.013	0.000019	4,645	0.07
Cooling Tower					2.75	1.74	0.006				
Lubricating Oil Vents			<0.01								
Diesel and Lubricating Oil Tanks			0.0021								
Natural Gas Piping Fugitives										73	
Natural Gas Maintenance + SU/SD Venting										168	
SF_6 Circuit Breakers										132.8	
Total Project Emissions	**126.35**	**289.69**	**101.52**	**31.78**	**86.77**	**85.76**	**84.03**	**30.35**	**0.000147**	**1,762,910**	**11.48**
Major Source Threshold	100	100	100	100	100	100	100	100	100	100,000	10/25
Major Source?	Yes	Yes	Yes	No	No	No	No	No	No	Yes	No
PSD Significant Net Emission Rate	40	100	40	40	25	15	10	7	0.6		
Subject to PSD Review?	Yes	Yes	Yes	No	Yes	Yes	Yes	Yes	No	Yes	

Table 3-15 Total Project Maximum Potential Annual Emissions/Siemens (tons/year)

Emission Unit	NO_X	CO	VOC	SO_2	PM	PM_{10}	$PM_{2.5}$	H_2SO_4	Pb	GHGs (CO_{2e})	Total HAPs
Combustion Turbine *w/*Duct Burner	120.89	98.11	56.06	33.76	83.22	83.22	83.22	12.9	---	1,782,510	11.56
Diesel Engine-Powered Emergency Generator	4.34	0.73	0.08	0.005	0.04	0.04	0.04	0.0007	0.000027	486	0.006
Diesel Engine-Powered Fire Pump	0.45	0.07	0.02	0.0008	0.01	0.01	0.01	0.00012	0.0000048	86	0.002
Auxiliary Boiler	1.94	7.18	0.98	0.41	1.37	1.37	1.37	0.05	0.000096	22,830	0.36
Fuel Gas Heater	0.48	1.45	0.13	0.09	0.26	0.26	0.26	0.009	0.000019	4,645	0.07
Cooling Tower					2.75	1.74	0.006				
Lubricating Oil Vents			<0.01								
Diesel and Lubricating Oil Tanks			0.0021								
Natural Gas Piping Fugitives										73	
Natural Gas Maintenance + SU/SD Venting										168	
SF_6 Circuit Breakers										132.8	
Total Project Emissions	**128.10**	**107.54**	**57.18**	**34.27**	**87.65**	**86.64**	**84.91**	**12.98**	**0.000147**	**1,810,931**	**12.00**
Major Source Threshold	100	100	100	100	100	100	100	100	100	100,000	10/25
Major Source?	Yes	Yes	No	No	No	No	No	No	No	Yes	No
PSD Significant Net Emission Rate	40	100	40	40	25	15	10	7	0.6		
Subject to PSD Review?	Yes	Yes	Yes	No	Yes	Yes	Yes	Yes	No	Yes	

Further discussion of emissions will be presented in context of the specific regulatory requirements.

3 Chronology

(only critical path items are presented)

Date	Description
04/15/2016	An application to construct a greenfield facility was received and assigned application no. 16A
06/16/2016	A "30-day" letter was sent stating the application has been deemed incomplete. The letter described the missing application elements most notably the air dispersion analysis.
08/08/2016	The missing application elements were received by the DAQ and the application was deemed complete. The Permittee also submitted a revised BACT analysis for sulfuric acid emissions.
08/24/2016	An electronic copy and hardcopy of the complete application was sent to Heather Ceron of the EPA.
08/24/2016	An electronic copy of the complete application was sent to all Federal Land Managers with an interest in North Carolina air permitting projects.
08/30/2016	The missing application elements were received by the DAQ and a follow-up letter was sent to the permittee deeming the application complete as of 08/08/2016.
09/28/2016	An email was received by the DAQ with an additional modeling analyses for PM2.5. In this analysis, the baseline date was considered to be the same as the "original" PM baseline date of January 6, 1975.
03/27/2017	Revised permit application and modeling analysis received in the RCO via email. The revised application was required because: 1.one of the proposed turbine option vendors provided revised performance data which reflects changes to the heat input, air flows, exhaust temperatures, stack parameters, and emissions; and 2. The proposed BACT for the pipeline natural gas sulfur content was revised.
4/18/2017	An email from David Keen was received stating: *The PM2.5 increment results presented in the March 2017 revised NTE modeling report are based on a 1975 TSP baseline. All PM2.5 sources that consume increment since that date were modeled. As we discussed yesterday, DAQ also needs the PM2.5 increment results based on a 2011 baseline. Since NTE is the only source that consumes PM2.5 increment based on a 2011 baseline, we can use the PM2.5 significant impact analysis results as a conservative representation of the PM2.5 increment consumption. Since the PM2.5 24-hr increment is based on the highest second highest modeled concentration, the highest modeled concentration from the significance analysis will be a conservative representation of increment consumption. As you can see from Table 4 on page 6-3 of the report, the PM2.5 impacts for both turbine cases are less than the increments.*
04/21/2017	Complete revised hardcopy of application received in the RCO.
~~MM/DD/YYYY~~	~~Public Notice published on NCDENR DAQ website andnewspaper ; concurrent public/EPA comment period begins~~

4 Regulatory review

The Project is subject to a variety of federal and state regulations pertaining to the construction or operation of air emission sources. DENR has the primary jurisdiction over air emissions produced by the Project by enforcing its own regulations as well as EPA's federal requirements. This section summarizes the applicability of various federal and state regulations to the Project. The following regulations and standards were reviewed for applicability to the proposed project:

- National Ambient Air Quality Standards (NAAQS);
- Prevention of Significant Deterioration Regulations;
- Non-Attainment New Source Review Regulations;
- Good Engineering Practice (GEP) Stack Height Regulations;
- New Source Performance Standards (NSPS);
- National Emission Standards for Hazardous Air Pollutants (NESHAPs) for Source Categories;
- Title V Operating Permit Program;
- Acid Rain Program Regulations (ARP);

- Risk Management Program (RMP);
- NOx Budget Trading Program;
- Cross-State Air Pollution Rule (CSAPR);
- Mandatory Greenhouse Gas Reporting;
- Greenhouse Gas Tailoring Rule;
- North Carolina Air Quality Rules, 15A NCAC 02D and 02Q; and
- North Carolina State Implementation Plan (SIP)

The applicability of these regulations is discussed at length in the application. Discussion in this review will not attempt to replicate the detail of the application but rather to confirm that all applicable requirements will be met by the Project.

National Ambient Air Quality Standards (NAAQS) (15A NCAC 02D .0400)
Prevention of Significant Deterioration Regulations (15A NCAC 02D .0530)
Non-Attainment New Source Review Regulations; (15A NCAC 02D .0531)
Good Engineering Practice (GEP) Stack Height Regulations; (15A NCAC 02D .0533)

This project will be located in Rockingham County. The attainment status for each criteria pollutant is either unclassifiable or in attainment, hence Non-Attainment New Source Review Regulations do not apply. Compliance with the NAAQS will be determined as required under Prevention of Significant Deterioration Regulations which will be discussed elsewhere in this review document. Good Engineering Practice (GEP) Stack Height Regulations will also be addressed when assessing compliance with all applicable NAAQS.

Title V Operating Permit Program; (15A NCAC 02Q .0500)
Under DENR's Title V Operating Permit regulations (15A NCAC 02Q .0500), a Title V permit is required for Major Stationary Sources. Based on the estimated potential emissions from the Project, the Project will be a Major Stationary Source subject to Title V permitting. During the initial permitting process however, the Permittee has opted for the application to be processed pursuant to 15A NCAC 02Q .0501(c)(2) and 02Q .0504, which allows for the application to be processed under the State permitting rules (02Q .0300) and the PSD rule (02D .0530). The Permittee will then have one year from the date of beginning operation of the facility or source to file an application following the Title V permitting procedures.

Compliance Assurance Monitoring (15A NCAC 02D .0614)
At the subject facility only the combustion turbine with duct burner unit (ID No. ES-1) has "potential pre-control device emissions" of an applicable regulated air pollutant greater than the Title V major source thresholds. The pollutants are NOx, and CO (for either the MHPSA or Siemens configuration. The MHPSA unit has post control NOx and CO emissions greater than Title V major source thresholds as such are defined as a "large pollutant-specific emissions unit" (PSEU) for those pollutants. The Siemens unit has post control NOx and emissions than Title V major source thresholds and as such are defined as a "large pollutant-specific emissions unit" (PSEU) for NOx. The NOx emissions however are regulated under NSPS Subpart KKKK and as such are exempted from CAM pursuant to 40 CFR 64.2 (b)(1). Pursuant to 40 CFR 64.5(a)(1), the Permittee will be required to address CAM requirements as part of the initial Title V permitting process.

No further review is necessary at this time.

Risk Management Program (RMP) (15A NCAC 02D .2100)
EPA's Risk Management Plan Rule (RMP), codified in 40 CFR Part 68, requires that facilities with large quantities of highly hazardous chemicals prepare and implement a program to prevent the accidental release of those chemicals. NTE is proposing to use a dilute (19 percent by weight) solution of aqueous ammonia for the SCR NOx control system in lieu of anhydrous or higher concentration aqueous ammonia solutions, which are regulated under RMP if used or stored in amounts greater than 10,000 pounds (anhydrous ammonia) or 20,000 pounds (aqueous ammonia in concentrations of 20 percent or greater). Therefore, the RMP regulations will not be applicable to the Project.

Mandatory Greenhouse Gas Reporting
On October 30, 2009, EPA published in 40 CFR Part 98 Mandatory Greenhouse Gas Reporting requirements. This rule requires facilities that emit greater than 25,000 metric tons per year of CO2e to report their greenhouse gases. Subpart D of 40 CFR Part 98 outlines the requirements for Electricity Generation. The Project will emit more than 25,000 metric tons of CO2e; therefore, greenhouse gas reporting will be required. This is a federally enforceable only requirement. North Carolina does not require the reporting of Greenhouse Gas emissions for emissions inventory purposes.

Further regulatory discussion will be presented on an emission source specific basis.

4.1 Combustion Turbines and Heat Recovery Steam Generators

The combined-cycle CT/HRSG package incorporates an advanced MHPSA M501GAC or Siemens SCC6-8000H combustion turbine. For purposes of developing maximum potential project emission rates and stack parameters and conducting the required regulatory compliance demonstrations, control technology evaluations, and air quality impact analyses for this air permit application, NTE obtained performance and emissions data for both combustion turbines in combined-cycle configuration. All required demonstrations were performed using the maximum potential emissions and other specifications from the two combustion turbine models.

In the combined-cycle process, ambient air is drawn into the compressor element of the CT through an inlet air filtration and silencing system. Inlet evaporative cooling may take place during periods of warm ambient temperatures and low relative humidity to further enhance overall production capability of the CT. After the evaporative cooler section, air enters the compressor section where it is compressed and channeled to the fuel/mix combustion stage of the CT. This section of the CT is commonly referred to as the gas generator section. The gas generator is the component that generates criteria and hazardous air pollutant emissions by means of the fuel combustion process. A transition duct within the CT directs the flow of hot gases from the gas generator to the power section of the turbine. Gas generator combustion products (hot gases) expand through the stages of the power turbine where the thermodynamic, or gas energy is converted to mechanical power.

This power is transmitted through rotation of the shaft to the generator for the CT, which is directly coupled to the turbine. The generator takes this rotative power and converts it to electricity.

The hot gases produced in the CT are directed into the HRSG through an exhaust transition duct where waste heat is captured and heat converted into steam energy before the exhaust gases exit the vertical stack for the HRSG. The HRSG contains the natural gas-fired duct burners that will be used at times to increase the temperature of the exhaust gases in the HRSG. This is done to maximize output of the steam cycle in the plant.

The steam produced in the HRSG is used in the ST to produce additional electrical power. Once the steam does its work in the ST, it is exhausted and condensed at a vacuum in the steam surface condenser. The cycle is a closed loop system as the condensate is reused to feed water to the HRSG. Circulating cooling water from the cooling tower is used to condense the steam in the condenser.

The source will appear in the permit as follows:

(MHPSA)

Emission Source ID No.	Emission source Description	Control Device ID No.	Control Device Description
ES-1	One nominal 500 MW natural gas-fired combined-cycle combustion turbine (CT) with duct burner (DB) (max. heat input HHV = 2,894 MMBtu/hr, CT only and 724 MMBtu/hr, DB only). CT equipped with dry low-NOx combustors	CD-1A	Selective Catalytic Reduction (SCR)
		CD-1B	CO oxidation catalyst

or

(Siemens)

Emission Source ID No.	Emission source Description	Control Device ID No.	Control Device Description
ES-1	One nominal 500 MW natural gas-fired combined-cycle combustion turbine (CT) with duct burner (DB) (max. heat input HHV = 2,973 MMBtu/hr, CT only and 698 MMBtu/hr, DB only). CT equipped with dry low-NOx combustors	CD-1A	Selective Catalytic Reduction (SCR)
		CD-1B	CO oxidation catalyst

As mentioned previously this emission source consists of a combustion turbine (CT), heat recovery steam generator (HRSG) equipped with a duct burner (DB) and a steam turbine (ST). Only the CT and DB involve combustion and hence the generation of pollutants. It is also worth noting that the Permittee is not planning (nor requesting) to operate the HRSG and ST independently of the CT. Thus, to simplify the discussion, this aggregate emission source will be referred to as ID No. ES-1. Specific mention to the various components will be made as necessary.

15A NCAC 02D .0503: PARTICULATES FROM FUEL BURNING INDIRECT HEAT EXCHANGERS
This rule limits PM emissions from fuel burning heat exchangers by the following equation:

E = 1.090*(Q)^(-0.2594) Equation 1
where:
E = allowable emission limit for particulate matter in lb/million Btu.
Q = maximum heat input in million Btu/hour.

Pursuant to 02D .0503(e):

> *The sum of maximum heat input of all fuel burning indirect heat exchangers at a plant site which are in operation, under construction, or permitted pursuant to 15A NCAC 02Q, shall be considered as the total heat input for the purpose of determining the allowable emission limit for particulate matter for each fuel burning indirect heat exchanger.*

For purposes of this rule, there are three fuel burning indirect heat exchangers at the proposed site:

(MHPSA)	
Auxiliary boiler -	85 MMBtu/hr
Fuel gas heater –	9 MMBtu/hr
Duct burner (HRSG + DB)	724 MMBtu/hr
Total =	818 MMBtu/hr

(Siemens)	
Auxiliary boiler -	85 MMBtu/hr
Fuel gas heater –	9 MMBtu/hr
Duct burner (HRSG + DB)	698 MMBtu/hr
Total =	792 MMBtu/hr

Using equation 1 above, the allowable PM emission rate from each of these sources is: 0.19 lb/MMBtu(MHPSA) or 0.19 lb/MMBtu (Siemens). Note that the heat input associated with the CT is not included in the analysis. In a practical sense, since there is only one stack, the CT PM emissions would contribute PM emissions. However, it will be shown that this is not of concern.

Based on the BACT analyses for ES-1 (Section 5.6.6 of this review), the Permittee is requesting the following BACT emission limitations for particulate matter which are more stringent that the allowable emission rates under this rule.

MHPSA	Siemens
0.0039 lb/MMBtu, CT only	0.0039 lb/MMBtu, CT only
0.0053 lb/MMBtu, CT + DB	0.0051 lb/MMBtu, CT + DB

These emission limitations will be enforced through the PSD permit conditions (02D .0530). Given the expected margin of compliance no additional monitoring, recordkeeping and reporting with respect to 02D .0503 will be required.

15A NCAC 02D .0521: CONTROL OF VISIBLE EMISSIONS

This rule limits visible emissions to no more than 20 percent opacity when averaged over a six-minute period. The combustion of natural gas generally does not result in significant visible emissions. Pursuant to current DAQ policy for natural gas combustion sources no monitoring, recordkeeping or reporting is required for the natural gas combustion in ES-1.

15A NCAC 02D .0524: NEW SOURCE PERFORMANCE STANDARDS
40 CFR Part 60 Subpart KKKK, Standards of Performance for Stationary Combustion Turbines

40 CFR Part 60 Subpart KKKK applies to each stationary combustion turbine with a heat input at peak load equal to or greater than 10 MMBtu per hour based on the higher heating value, which commenced construction, modification, or reconstruction after February 18, 2005.

The peak load heat input rate of the turbine (without the heat input of DBs) is much greater than 10 MMBtu/hr firing natural gas. Therefore, the Project's CT is subject to this regulation.

Emission Limits for NOx

ES-1 is subject to an emission standard of 15 ppm at 15 percent O2, when fired with natural gas. If the turbine operates at partial load (less than 75 percent of peak load) or if the turbine operates at temperatures less than 0ºF, a NOx limit of 96 ppm at 15 percent O2 will apply. The HRSG will not be operated independently of the CT.

The Project has chosen to comply with concentration-based NOx emission standards. Under the proposed BACT limits to comply with 02D .0530 (PSD), the turbine will reduce its NOx emissions to 2 ppm at 15 percent O2 using low-NOx combustors and selective catalytic reduction while burning natural gas. Therefore, compliance with the NSPS NOx emission limits is expected.

The actual compliance with these emission standards will be verified during the initial performance test and via continuous monitoring with NO2 and O2 CEMS.

EmissionLimits for SO2

ES-1 will be subject to an emission limit of 0.9 lb/MWh gross output or the turbines must not burn any fuel which contains total potential sulfur emissions in excess of 0.06 lb SO2/MMBtu heat input.

The Project will comply with the input-based emission standard of 0.06 lb SO2/MMBtu heat input. ES-1 will burn only pipeline quality natural gas. Using 0.75 grains sulfur/100 ft3 sulfur content (BACT limit) and approximately 1,020 Btu/ft3 (HHV) heat content for natural gas, the potential SO2 emission rate for ES-1 is estimated as 0.0021 lb/MMBtu. Therefore, compliance is expected with this standard. The Permittee shall demonstrate compliance with the applicable SO_2 emission limit by making demonstrations that the fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel specifies that the total sulfur content for natural gas is 20 grains of sulfur or less per 100 standard cubic feet, and has potential sulfur dioxide emissions of less than 0.06 lb SO_2/MMBtu heat input in accordance with §60.4365(a).

15A NCAC 02D .1111: MAXIMUM ACHIEVABLE CONTROL TECHNOLOGY

The following MACTs are potentially applicable to ES-1.

Subpart DDDDD - NESHAP for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters

Subpart YYYY NESHAP for Stationary Combustion Turbines

These MACTs are only applicable at major sources of HAPs. This facility is considered to be a minor source of HAPs with a facility-wide PTE of less than 10/25 tpy for individual/total HAP in either turbine configuration.

Subpart JJJJJJ NESHAP for Industrial, Commercial, and Institutional Boilers Area Sources)
This MACT is applicable only at minor sources of HAPs and is potentially applicable to HRSG. The HRSG is defined as a waste heat boiler under the rule (even with the added heat from the duct burner), which is also excluded from the definition of a boiler. Therefore, Subpart JJJJJJ is not applicable to the HRSG.

15A NCAC 02Q .0402 ACID RAIN PERMITTING PROCEDURES
The Acid Rain Program is codified in 40 CFR Parts 72 through 78 and implemented by 15A NCAC 02Q .0400. This program aims to reduce acid rain by reduction of SO2 and NOx from utility units that have a nameplate electricity generation capacity greater than 25 MW. This utility unit meets this criterion. However, the unit is not an affected unit under the NOx Emission Reduction Program (40 CFR 76) as it is not a coal-fired utility unit. The permit application expands on the requirements of the acid rain program all of which trigger on the submittal of an Acid Rain Permit application. Pursuant 40 CFR 72.30(a)(2), the Permittee is required to:

"submit a complete Acid Rain permit application governing such unit to the permitting authority at least 24 months before the later of January 1, 2000 or the date on which the unit commences operation."

Hence the issuance of this permit does not depend on the requirements of the Acid Rain Program and are not discussed further. A permit condition will be placed into the permit to address this application submittal requirement.

Federal Enforceable Only
Cross-State Air Pollution Rule (CSAPR)
The Cross-State Air Pollution Rule (CSAPR), 40 CFR Part 97, requires 28 states to reduce power plant emissions that contribute to ozone and fine particle pollution in other states. . CSAPR is the successor to the Clean Air Interstate Rule (CAIR), which was invalidated by the courts. North Carolina state regulations formerly implementing CAIR (15A NCAC 02D .2400) were repealed effective in early 2016.

The applicability criteria and definitions in CSAPR are similar to those in the Acid Rain Program. The rule generally applies to fossil fuel-fired units serving a generator with a nameplate capacity of more than 25 MW, and producing electricity for sale. Therefore, the project will be subject to CSAPR.

CSAPR will be implemented by the federal government directly as a Federal Implementation Plan (FIP) (see 40 CFR 52). Thus it is not addressed in North Carolina's State Implementation plan (SIP) and no state rules apply. No further review is necessary at this time. It is anticipated that the CSAPR requirements will be addressed during the initial TV permitting process. A permit condition will be included in the permit indicating CSAPR requirements as "Federal Enforceable Only".

State Enforceable Only
15A NCAC 02D .1100 - CONTROL OF TOXIC AIR POLLUTANTS
See discussion elsewhere in this review as it has facility-wide implications.

15A NCAC 02D .0530: PREVENTION OF SIGNIFICANT DETERIORATION
See discussion elsewhere in this review as it has facility-wide implications.

4.2 Natural Gas-Fired Auxiliary Boiler and Fuel Gas Heater

A natural gas-fired auxiliary boiler, rated at 85 MMBtu/hr, will be used primarily to provide high-temperature steam when the CT is offline in order to accommodate more rapid ST startups after extended shutdowns and potentially to provide fuel gas heating. It will not operate once the CT has achieved steady-state operations; however, there will be some overlapping operation during startup and shutdown of the CT. Total operation of the auxiliary boiler will range from 760 hours to 4,560 hours per 12-month period depending on the specific operating scenario.

The auxiliary boiler will be natural gas-fired and operate as needed to keep the HRSG warm during periods of turbine shutdown and provide sealing steam to the steam turbine during warm and hot starts. The auxiliary boiler will have a maximum input capacity of 85 MMBtu/hr, and will be limited to a maximum of 4,560 hours of operation per year (Mid-Range Dispatch operation). Potential criteria and HAP emissions are estimated based on vendor-supplied information and natural gas fuel specifications.

The natural gas-fired fuel gas heater will operate as necessary to condition the natural gas prior to combustion to prevent condensation. The maximum rated capacity of the fuel gas heater will be 9 MMBtu/hr and the heater will have the potential to operate for 8,760 hours per year at maximum capacity. Potential criteria and HAP emissions are estimated based on vendor-supplied information and natural gas fuel specifications.

Table 3-9 Potential Hourly and Annual Emissions from Natural Gas-Fired Boiler and Fuel Gas Heater

	Auxiliary Boiler[1]		**Fuel Gas Heater[2]**	
Pollutant	**lb/hr**	**TPY**	**lb/hr**	**TPY**
NO_X	0.85	1.94	0.11	0.48
CO	3.15	7.18	0.33	1.45
VOC	0.43	0.98	0.03	0.13
$PM_{10}/PM_{2.5}$	0.60	1.37	0.06	0.26
SO_2	0.18	0.41	0.02	0.09
H_2SO_4	0.03	0.07	0.003	0.013
Lead	4.2E-05	9.6E-05	4.4E-06	1.9E-05
NH_3	0.26	0.59	0.03	0.13
GHG	10,014	22,830	1,061	4,646
Total HAPs	0.16	0.36	0.017	0.07
Highest (Hexane)	0.15	0.34	0.016	0.07

[1]Based on 4,560 hrs/yr operation.
[2]Based on 8,760 hrs/yr operation.

These sources will appear in the permit as follows:

Emission Source ID No.	**Emission Source Description**	**Control Device ID No.**	**Control Device Description**
ES-2	Natural Gas-fired Auxiliary Boiler with Low NOx burners (138 MMBtu/hr maximum heat input)	NA	NA
ES-3	Natural gas-fired fuel gas heater (9 MMBtu/hr per hour maximum heat input) with low NOx burners	NA	NA

15A NCAC 02D .0503: PARTICULATES FROM FUEL BURNING INDIRECT HEAT EXCHANGERS
This rule limits PM emissions from fuel burning heat exchangers by the following equation:

E = 1.090*(Q)^(-0.2594) Equation 1
where:
E = allowable emission limit for particulate matter in lb/million Btu.
Q = maximum heat input in million Btu/hour.

Pursuant to 02D .0503(e):

> *The sum of maximum heat input of all fuel burning indirect heat exchangers at a plant site which are in operation, under construction, or permitted pursuant to 15A NCAC 02Q, shall be considered as the total heat input for the purpose of determining the allowable emission limit for particulate matter for each fuel burning indirect heat exchanger.*

For purposes of this rule, there are three fuel burning indirect heat exchangers at the proposed site:

(MHPSA)

Auxiliary boiler -	85 MMBtu/hr
Fuel gas heater –	9 MMBtu/hr
Duct burner (HRSG + DB)	724 MMBtu/hr
Total =	818 MMBtu/hr

(Siemens)

Auxiliary boiler -	85 MMBtu/hr
Fuel gas heater –	9 MMBtu/hr
Duct burner (HRSG + DB)	698 MMBtu/hr
Total =	792 MMBtu/hr

Using equation 1 above, the allowable PM emission rate from each of these sources is: 0.19 lb/MMBtu (MHPSA) or 0.19 lbMMBtu (Siemens).

Based on the BACT analyses for these units (Section 5.11.3 of the application), the Permittee is requesting the following permit emission limitations which are based on AP-42 emission factors:

Auxiliary boiler -	0.007 lb/MMBtu
Fuel gas heater –	0.007 lb/MMBtu

These emission limitations will be enforced through the PSD permit conditions (02D .0530). Given the expected margin of compliance no additional monitoring, recordkeeping and reporting with respect to 02D .0503 will be required.

15A NCAC 02D .0516: SULFUR DIOXIDE EMISSIONS FROM COMBUSTION SOURCES
These sources will combust natural gas and is subject to the 2.3 pounds per million Btu heat input limitation.
Based upon a maximum sulfur content of 0.75 grains /100SCF, the combustion of natural gas is expected to result in SO2 emissions on the order of 0.0021 lb/MMBtu. Given the expected margin of compliance, and consistent with current DAQ policy, no monitoring, recordkeeping and reporting will be required.

15A NCAC 02D .0521: CONTROL OF VISIBLE EMISSIONS
The combustion of natural gas usually results (based on experience of similar sources at other facilities) in visible emissions well below the 20% allowed by this rule. Given the expected margin of compliance, and consistent with current DAQ policy, no monitoring, recordkeeping and reporting will be required.

15A NCAC 02D .0524: NEW SOURCE PERFORMANCE STANDARDS
40 CFR Part 60, Subpart Dc – Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

As a natural gas-fired boiler with a heat input greater than 10 but less than or equal to 100 MMBtu/hr, the proposed auxiliary boiler is subject to NSPS Subpart Dc. Pursuant to 40 CFR 60.48c(g)(2), the Permittee shall record and maintain records of the amount of fuel combusted during each calendar month. Since it is not permitted to burn fuels other than natural gas (e.g., wood, oil, coal) which have emission limitations under this rule, no potential compliance issues are expected and hence no other monitoring, recordkeeping and reporting is necessary to ensure compliance with this rule. No further review is necessary. No other NSPS rules apply to this source.

The fuel gas heater has a heat input below the applicability threshold for this rule. No other NSPS rules apply to this source.

15A NCAC 02D .1111 MAXIMUM ACHIEVABLE CONTROL TECHNOLOGY
40 CFR 63, Subpart JJJJJJ - National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources

Since the project will be a minor source of HAPs, this rule was reviewed for applicability to the Project's auxiliary boiler and fuel gas heater. The auxiliary boiler and fuel gas heater are defined as gas-fired boilers, which are specifically exempted from this subpart in accordance with § 63.11195(e). Since it is not permitted to burn other fuels which do have requirements under this rule, no potential compliance issues are expected and hence no monitoring, recordkeeping and reporting is necessary to ensure compliance with this rule. No further review is necessary. Therefore, Subpart JJJJJJ is not applicable to the auxiliary boiler.

State Enforceable Only
15A NCAC 02D .1100 - CONTROL OF TOXIC AIR POLLUTANTS
See discussion elsewhere in this review.

15A NCAC 02D .0530: PREVENTION OF SIGNIFICANT DETERIORATION
See discussion elsewhere in this review.

4.3 Emergency Diesel Engines

The project will include a diesel engine powered emergency generator (1250 kW generator output, 1,675 bhp engine output) and a 300 bhp diesel engine powered fire pump.

The emergency diesel engine powered standby emergency generator will allow maintenance of vital plant loads during power outages or maintenance on the switchyard. The diesel engine generator and fire pump will only be operated during power interruptions to provide emergency power, lighting, and fire protection when the project CT is not operating and at most once per week for less than 30 minutes for operational testing purposes when the CT is operational. The project is proposing to accept operating restrictions on the emergency generator and fire pump through the air quality permit that would limit annual cumulative non-emergency operation (e.g., engine testing) to less than 100 hours per consecutive 12-months for each engine. The 100-hour operational restriction for each engine would not apply towards operation during actual emergency situations. Potential emissions from each emergency diesel engine have been estimated based on 500 hours per year of operation.

Ultra-low sulfur (15 ppm by weight sulfur) diesel fuel will be used in both the fire pump and standby generator engines. An approximately 5000-gallon diesel storage tank will be located on site to supply diesel fuel for the two diesel engines. A 300-gallon double-walled tank will be used for the diesel fire water pump. A 500-gallon double-walled base tank will be used for the standby generator.

Annual potential emissions based on these emissions factors and a maximum of 500 hours per year are summarized in Table 3-10 and detailed emissions calculations can be found in Appendix B, Tables B-7 and B-8.

Table 3-10 Potential Emissions for Diesel Engine Generator and Fire Pump

Diesel Engine Generator		
Pollutant	**Emissions (lbs/hr)**	**Emissions (tons/yr)**
NO_X	17.37	4.34
CO	2.92	0.73
VOC	0.33	0.08
PM_{10} /$PM_{2.5}$	0.15	0.04
SO_2	0.02	0.005
H_2SO_4	0.003	0.0007
NH_3	0.61	0.15
Lead	1.10E-04	2.70E-05
GHG	1,944	486
Total HAPs	0.02	0.006
Highest HAP (Benzene)	0.01	0.003

300 HP Diesel Fire Pump		
Pollutant	**Emissions (lbs/hr)**	**Emissions (tons/yr)**
NO_X	1.79	0.45
CO	0.26	0.07
VOC	0.07	0.02
PM_{10}/$PM_{2.5}$	0.05	0.01
SO_2	0.003	0.0008
H_2SO_4	0.0005	0.00012
NH_3	0.10	0.02
Lead	1.90E-05	4.80E-06
GHG	345	86
Total HAPs	0.008	0.002
Highest HAP (Formaldehyde)	0.002	0.0006

The engines will appear in the permit as follows:

Emission Source ID No.	Emission Source Description	Control Device ID No.	Control Device Description
ES-4	Diesel Fuel-fired Standby Emergency Generator (1,675 maximum brake horsepower)	NA	NA
ES-5	Diesel Fuel-fired Emergency Fire Pump Engine (300 maximum brake horsepower)	NA	NA

15A NCAC 02D .0524: NEW SOURCE PERFORMANCE STANDARDS 40 CFR Part 60 Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

40 CFR Part 60, Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, applies to the emergency fire pump engine and the emergency standby generator proposed for the Project. The rule requires manufacturers of such engines to meet emission standards that are phased in for the size, type of engine application, and model year of the engine. Owners and operators of covered engines are required to configure, operate, and maintain the engines according to specifications and instructions provided by the engine manufacturer and to maintain records demonstrating compliance. Diesel engines subject to Subpart IIII must meet the ultra-low sulfur content standard specified in 40 CFR Part 80.510(b) of 15 ppm. Emergency engines also must install an hour-meter and track hours of operation in emergency and non-emergency service.

The Project will comply with the requirements applicable to owners and operators of emergency engines by purchasing a fire pump engine certified to the emission standards listed in Table 4 to 40 CFR Part 60, Subpart IIII and an emergency generator engine certified to the emission standards in 60.4202, pursuant to 60.4211(c).

The permit will include all the requirements of NSPS IIII applicable to these engines.

15A NCAC 02D .1111: MAXIMUM ACHIEVABLE CONTROL TECHNOLOGY - 40 CFR Part 63, Subpart ZZZZ, National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines.

The proposed diesel engine-powered emergency generator and fire water pump are subject to Subpart ZZZZ, since this standard is applicable to both major and non-major (Area) sources of HAPs. However, in accordance with 40 CFR 63.6590(c), new or reconstructed compression ignition engines at Area sources must meet the requirements of 40 CFR 60 Subpart IIII to comply with requirements of Subpart ZZZZ. No other requirements apply under Subpart ZZZZ.

The permit will contain a permit condition that indicates that compliance with the applicable requirements of NSPS IIII will indicate compliance with Subpart ZZZZ.

15A NCAC 02D .0516: SULFUR DIOXIDE EMISSIONS FROM COMBUSTION SOURCES
Under this rule, the combustion sources are subject to a SO2 emission limit of 2.3pounds per million Btu heat input.

However, 02D .0516 states:

> *(b) A source subject to an emission standard for sulfur dioxide in Rules .0524, .0527, .1110, .1111, .1205, .1206, .1210, or .1211 of this Subchapter shall meet the standard in that particular rule instead of the standard in Paragraph (a) of this Rule.*

These engines are subject to 02D .0524 NSPS Subpart IIII which has a more stringent sulfur standard. Thus, this rule does not apply to these emergency engines.

15A NCAC 02D .0521: CONTROL OF VISIBLE EMISSIONS
Under this rule, each source is subject to a 20 percent opacity limit when averaged over a 6-minute period (with some exceptions).

However, 02D .0521(b) states (paraphrased):

> *(b) Scope. This Rule shall apply to all fuel burning sources and to other processes that may have a visible emission. However, sources subject to a visible emission standard in Rules .0506, .0508, .0524, .0543, .0544, .1110, .1111,*

.1205, .1206, .1210, .1211, or .1212 of this Subchapter shall meet that standard instead of the standard contained in this Rule.

These engines are subject to 02D .0524 NSPS Subpart IIII, which has a “smoke” standard but it does not apply to single speed engines. Hence 02D .0521 applies. Consistent with current DAQ policy however, no monitoring, recordkeeping or reporting is required from the firing of diesel fuel in these engines.

<u>State Enforceable Only</u>
15A NCAC 02D .1100 - CONTROL OF TOXIC AIR POLLUTANTS
See discussion elsewhere in this review.

15A NCAC 02D .0530: PREVENTION OF SIGNIFICANT DETERIORATION
See discussion elsewhere in this review.

4.4 Cooling Tower (ID No. ES-6)

The steam produced in the Heat Recovery Steam Generator (HRSG) is used in the Steam Turbine (ST) to produce additional electrical power. Once the steam does its work in the ST, it is exhausted and condensed at a vacuum in the steam surface condenser. The cycle is a closed loop system as the condensate is reused as feed water to the HRSG. Circulating cooling water from the multiple-cell mechanical draft wet cooling tower is used to condense the steam in the condenser.

In this type of cooling tower, electric motor-driven fans at the top of each cooling tower cell maintain a flow of air through the cooling tower. Circulating water pumps move the water through the steam condenser, where it picks up heat, to the top of the cooling tower. At the top of the cooling tower, the warm water is distributed onto a perforated deck. The water then falls through the perforations and is cooled by evaporation as it falls through baffles (called "fill") to a basin at the bottom of the tower and air is induced up through the tower by the fans. Cool water from the cooling tower basin is returned to the condenser via the circulating water pumps.

The cooling towers will operate continuously when the CT is operated. The cooling towers will emit small amounts of PM emissions associated with wet cooling tower drift losses. Drift loss will be minimized with high-efficiency drift eliminators.

The cooling tower is expected to have a recirculating flow rate of 126,340 gallons per minute and maximum 2,000 milligrams per liter (mg/1) of total dissolved solids (TDS) based on use of municipal water supply for cooling water. PM10/PM2_5 emissions from the cooling tower are estimated using a particulate distribution spreadsheet developed by Environment Canada and conservatively assuming eight cycles of concentration. The cooling tower will utilize high efficiency (0.0005%) drift eliminators. The maximum estimated potential PM10 and PM25 emissions from the multi-cell cooling tower system are 0.40 lb/hr and 1.74 tpy PM10 and 0.001 lb/hr and 0.006 tpy PM2.5. The emissions calculations and assumptions are provided in Appendix B, Table B-9 of the application.

The cooling tower will appear in the air permit as follows:

Emission Source ID No.	**Emission source Description**	**Control Device ID No.**	**Control Device Description**
ES-6	Multi-cell cooling tower (126,340 gallons per minute nominal recirculating flow rate)	CD-6	Mist eliminator (0.0005 percent drift loss)

15A NCAC 02D .0521: CONTROL OF VISIBLE EMISSIONS

Cooling towers are sources of PM emissions and hence potentially visible emissions. However, the visible emissions are primarily the result of the water droplets themselves. EPA Reference Method 9 is used to determine compliance with visible emission limitations (expressed as a percent opacity). The method provides for opacity determination “beyond the point in the plume at which condensed water vapor is no longer visible.”

Based on the actual performance of other cooling towers, the opacity as determined by Method 9 is expected to be essentially 0%. Therefore, consistent with current DAQ policy, no monitoring, recordkeeping and reporting will be required.

15A NCAC 02D .0530: PREVENTION OF SIGNIFICANT DETERIORATION

See discussion elsewhere in this review.

4.5. State Enforceable Only - 15A NCAC 02D .1100: Control of Toxic Air Pollutants and 15A NCAC 02Q .0700 Toxic Air Pollutant Procedures

All permitted sources, with the exception of the cooling tower, emit toxic air pollutants (TAPs) regulated under 15A NCAC 02D .1100. For a number of TAPs, the permittee estimates emissions over rates required to have a permit under 02Q .0700, specifically 02Q .0711.

The Permittee performed a dispersion modeling analysis for the following TAPs: Sulfuric Acid mist, Ammonia, Benzene, Chromic Acid and Formaldehyde. All TAP emitting sources were included in the analysis. Emission rates modeled were based on the "worst case" (i.e., emission-maximizing) operating scenarios for each turbine option. The plant wide TAP emissions are provided in Appendix B, Table B-12. See section 3.7 of the application for additional information.

The results of this modeling analysis are summarized in this review document at Section 6, Non-Regulated Pollutant Impact Analysis (North Carolina Toxics) and in section 6.7 of the application. All TAPs were modeled well below (less than 10%) their respective Acceptable Ambient Levels (AALs).

These modeled emission rates will be included in the air permit as emission limitations. However, pursuant to 15A NCAC 02Q .0702(a)(27), the MACT Subpart ZZZZ affected emergency engine and fire pump are exempt from any permitting requirements under 02Q .0700. The permit will not include any emission limitation on these two sources. Given the margins of compliance and enforceable limitations elsewhere in the permit that will ensure that the TAP emissions in practice are well represented by this modeling analysis, no M/R/R will be required to demonstrate compliance with these specific emission limitations.

5. 15A NCAC 02D .0530: Prevention Of Significant Deterioration

The PSD regulations are designed to ensure that the air quality in current attainment areas does not significantly deteriorate beyond baseline concentration levels. PSD regulations specifically apply to the construction of EPA-defined Major Stationary Sources in areas designated as attainment or unclassified attainment for at least one of the criteria pollutants. North Carolina has incorporated EPA's PSD regulations (40 CFR 51.166) into its air pollution control regulations in 15A NCAC 02D .0530. and 02D .0533.

Combined-cycle CTs with HRSGs are considered as fossil fuel-fired steam electric plants. Therefore, the applicable PSD threshold for the Project is 100 TPY of potential emissions. Once it is determined that a pollutant exceeds the major source threshold, each of the remaining pollutants is subject to PSD review if the potential to emit (PTE) exceeds the Significant Emission Rates listed in Table 4-3 of the application. Therefore, Project pollutants subject to PSD review are NOx, CO, VOC, PM10, PM2.5, H_2SO_4 and GHG.

The elements of a PSD review are as follows:

1) A Best Available Control Technology (BACT) Determination as determined by the permitting agency on a case-by-case basis in accordance with 40 CFR 51.166(j),
2) An Air Quality Impacts Analysis including Class I and Class II analyses, and
3) An Additional Impacts Analysis including effects on soils and vegetation, and impacts on local visibility in accordance with 40 CFR 51.166(o).

5.1 Best Available Control Technology (BACT) Determination Methodology

Under PSD regulations, the basic control technology requirement is the evaluation and application of BACT. BACT is defined as follows [40 CFR 51.155 (b)(12)]:

> ***An emissions limitation...based on the maximum degree of reduction for each pollutant... which would be emitted from any proposed major stationary source or major modification which the reviewing authority, on a case-by-case basis, taking into account energy, environment, and economic impacts and other costs, determines is achievable... for control of such a pollutant.***

As evidenced by the statutory definition of BACT, this technology determination must include a consideration of numerous factors. The structural and procedural framework upon which a decision should be made is not prescribed by Congress under the Act. This void in procedure has been filled by several guidance documents issued by the federal EPA. The only final guidance available is the October 1980 "Prevention of Significant Deterioration – Workshop Manual." As the EPA states on page II-B-1, "A BACT determination is dependent on the specific nature of the factors for that **particular case**. The depth of a BACT analysis should be based on the quantity and type of pollutants emitted and the **degree of expected air quality impacts**." (emphasis added). The EPA has issued additional DRAFT guidance suggesting the use of what they refer to as a "top-down" BACT determination method. While the EPA Environmental Appeals Board recognizes the top-down approach for delegated state agencies,[1] this procedure has never undergone rulemaking and as such, the process is not binding on fully approved states, including North Carolina.[2] The Division prefers to follow closely the statutory language when making a BACT determination and therefore bases the determination on an evaluation of the statutory factors contained in the definition of BACT in the Clean Air Act. As stated in the legislative history and in EPA's final October 1980 PSD Workshop Manual, each case is different and the State must decide how to weigh each of the various BACT factors. North Carolina is concerned that the application of EPA's DRAFT suggested a top-down process will result in decisions that are inconsistent with the Congressional intent of PSD and BACT. The following are passages from the legislative history of the Clean Air Act and provide valuable insight for state agencies when making BACT decisions.

> The decision regarding the actual implementation of best available technology is a key one, and the **committee places this responsibility with the State**, to be determined on a case-by-case judgment. It is recognized that the phrase has broad flexibility in how it should and can be interpreted, depending on site.

[1] See, http://es.epa.gov/oeca/enforcement/envappeal.html for various PSD appeals board decisions including standard for review.
[2] North Carolina has full authority to implement the PSD program, 40 CFR Sec. 52.1770

> In making this key decision on the technology to be used, the State is to take into account energy, environmental, and economic impacts and other costs of the application of best available control technology. **The weight to be assigned to such factors is to be determined by the State**. Such a flexible approach allows the adoption of improvements in technology to become widespread far more rapidly than would occur with a uniform Federal standard. The only Federal guidelines are the EPA new source performance and hazardous emissions standards, which represent a floor for the State's decision.
>
> This directive enables the State to consider the size of the plant, the increment of air quality which will be absorbed by any particular major emitting facility, and such other considerations as anticipated and desired economic growth for the area. This allows the States and local communities judge how much of the defined increment of significant deterioration will be devoted to any major emitting facility. If, under the design which a major facility proposes, the percentage of increment would effectively prevent growth after the proposed major facility was completed, the State or local community could refuse to permit construction, or limit its size. **This is strictly a State and local decision; this legislation provides the parameters for that decision.**
>
> One of the cornerstones of a policy to keep clean areas clean is to require that new sources use the best available technology available to clean up pollution. One objection which has been raised to requiring the use of the best available pollution control technology is that a technology demonstrated to be applicable in one area of the country in not applicable at a new facility in another area because of the differences in feedstock material, plant configuration, or other reasons. **For this and other reasons the Committee voted to permit emission limits based on the best available technology on a case-by-case judgment at the State level.** [**emphasis added**]. This flexibility should allow for such differences to be accommodated and still maximize the use of improved technology.
>
> Legislative History of the Clean Air Act Amendments of 1977.

The BACT analysis provided by NTE for the proposed Project was conducted <u>consistent with the above definition as well as EPA's five step "top-down" BACT process</u>. The "top down" methodology results in the selection of the most stringent control technology in consideration of the technical feasibility and the energy, environmental, and economic impacts. Control options are first identified for each pollutant subject to BACT and evaluated for their technical feasibility. Options found to be technically feasible are ranked in order of their effectiveness and then further evaluated for their energy, economic, and environmental impacts. In the event that the most stringent control identified is selected, no further analysis of impacts is performed. If the most stringent control is ruled out based upon economic, energy, or environmental impacts, the next most stringent technology is similarly evaluated until BACT is determined.

After establishing the baseline emissions levels required to meet any applicable NSPS, NESHAPs, or SIP limitations, the "top-down" procedure followed for each pollutant subject to BACT is outlined as follows:

- Step 1: Identify of all available control options - from review of EPA RACT/BACT/LAER Clearinghouse (RBLC), agency permits for similar sources, literature review and contacts with air pollution control system vendors.
- Step 2: Eliminate technically infeasible options - evaluation of each identified control to rule out those technologies that are not technically feasible (i.e., not available and applicable per EPA guidance).
- Step 3: Rank remaining control technologies - "Top-down" analysis, involving ranking of control technology effectiveness.
- Step 4: Evaluate most effective controls and document results – Economic, energy, and environmental impact analyses are conducted if the "top" or most stringent control technology is not selected to determine if an option can be ruled out based on unreasonable economic, energy or environmental impacts.
- Step 5: Select the BACT – the highest-ranked option that cannot be eliminated is selected, which includes development of an achievable emission limitation based on that technology.

NTE also considered case-by-case considerations, achievability in practice and redefining the source as fully explained in the permit application. "

<u>To facilitate cross referencing, the BACT analysis as presented in this review document will maintain the section/paragraph numbering scheme contained in the submitted application. Much of the language will be excerpted directly in abbreviated form from the application with additional narrative provided by the DAQ.</u>

5.1.3 Identification of Potential Control Technologies

Potentially applicable emission control technologies were identified by researching the EPA control technology database, technical literature, control equipment vendor information, state permitting authority files, and by using process knowledge and engineering experience. The RBLC, a database made available to the public through the EPA's Office of Air Quality Planning and Standards (OAQPS) Technology Transfer Network (TTN) , lists technologies and corresponding emission limits that have been approved by regulatory agencies in permit actions. These technologies are grouped into categories by industry and can be referenced in determining what emissions levels were proposed for similar types of emissions units.

Searches of the RBLC database were performed in February 2016 to initially identify the emission control technologies and emission levels that were determined by permitting authorities as BACT or LAER since 2014 (when the Kings Mountain Energy Center in Cleveland County was permitted) for emission sources comparable to the proposed combined-cycle CT. The Large Combined Cycle and Cogeneration Natural Gas-Fired Turbines (RBLC Code 15.210) category was searched.

Upon completion of the RBLC search, relevant vendor information, pending permit applications, and issued permits not included in the RBLC were also reviewed. Sources of information searched included EPA Region IV's National Combustion Turbine List, California Air Resources Board (CARB) BACT Clearinghouse, and a Google search for permits not yet entered into a published data base. Appendix D presents summary tables of relevant BACT and LAER determinations by pollutant for combined-cycle CTs firing natural gas.

Although the accuracy of <u>all</u> the information provided above was not independently verified by the DAQ, a review of the RBLC database support the claims with respect to stringency and representativeness of the BACT proposed for the Project.

5.2 BACT for CT Nitrogen Oxides (NOX)

The proposed project will be subject to BACT for NO_X, because estimated potential emissions of NOx will be greater than the 100 TPY major source threshold and the 40 TPY PSD significant emission rate threshold applicable to a major source subject to PSD review. This section demonstrates that the proposed NO_X emissions and controls meet BACT requirements.

The exhaust from the turbines will be combined with the exhaust from the duct burners. There are no options to control the exhausts independently and thus the control options will apply to the combined exhaust.

5.2.1 Minimum NOX Regulatory Requirements

The NSPS (Subpart KKKK) limits applicable to NO_X emissions from natural gas-fired combined-cycle CTs are as follows:

- 15 ppm @ 15 percent O_2 or 0.43 lb/MWh, when fired with natural gas
- 96 ppm @ 15 percent O_2 or 4.7 lb/MWh. if the turbines operate at partial load (less than 75 percent of peak load) or if the turbines operate at temperatures less than 0°F
- 54 ppm @ 15 percent O_2 or 0.86 lb/MWh, applicable to the HRSG, if operated independently of the CT (Note: the HRSG will not be operated independently of the CT)

5.2.2 Identification of Available NOX Control Technologies (Step 1)

NO_X is formed during the combustion of fuel and is generally classified as either thermal NO_X or fuel NO_X. Thermal NO_X results when atmospheric nitrogen is oxidized at high temperatures to produce nitric oxide (NO), nitrogen dioxide (NO_2) and other oxides of nitrogen. The major factors influencing the formation of thermal NO_X are temperature, concentrations of oxygen in the inlet air, and residence time within the combustion zone. Fuel NO_X is formed from the oxidation of chemically bound nitrogen in the fuel. Fuel NO_X is generally minimal for natural gas combustion. Other possible types of NO_X formation mechanisms, such as prompt NO_X, also contribute minimally to total NO_X formation in natural gas-fired CTs. As such, NO_X formation from combustion of natural gas is due mostly to thermal NO_X formation.

Reduction in NO_X formation can be achieved using combustion controls and/or flue gas treatment (post-combustion controls). Based upon a review of RBLC search results, existing permits for similar combined-cycle CTs, CT vendor information and technical literature, the following combustion and post-combustion controls were identified for further evaluation:

Combustion control options include:

- Fuel Selection (fuel-NO_X control)
- Water/Steam Injection
- Dry Low-NO_X Combustors
- Catalytic Combustion (KLean)

Post-combustion control options include:

- Selective Catalytic Reduction
- $EMx^{TM}/SCONO_X$
- Selective Non-Catalytic Reduction (SNCR)

5.2.2.1 Fuel Selection (Fuel-NOX Control)

The proposed project's CT and DB will be fueled exclusively with natural gas. Further discussion is provided in the application.

5.2.2.2 Water/Steam Injection (WI)

Injection of either water or steam as a diluent directly into the combustor lowers the flame temperature and thereby reduces thermal NO_X formation. WI is typically not used for natural gas firing, as uncontrolled NO_X emissions are less due to negligible nitrogen content of natural gas. Further discussion is provided in the application.

5.2.2.3 Dry Low-NOX (DLN) Combustor

Lean pre-mix or DLN combustors are designed to control peak combustion temperature, combustion zone residence time and combustion zone free oxygen, thereby minimizing thermal NO_X formation. DLN combustors have been employed successfully for natural gas-fired CTs for more than fifteen years. Further discussion is provided in the application.

5.2.2.4 Catalytic Combustion (KLean)

Catalytic combustors, marketed under trade names such as KLean (formerly XONON™), use a catalyst to allow the combustion reaction to take place with a lower peak flame temperature in order to reduce thermal NO_X formation. KLean uses a flameless catalytic combustion module followed by completion of combustion (at lower temperatures) downstream of the catalyst. Catalytic combustors such as KLean have not been demonstrated on large-scale utility CTs such as the M501GAC or SCC6-8000H turbine, so the technology is not available for use in the proposed project's CT. Further discussion is provided in the application.

5.2.2.5 Selective Catalytic Reduction (SCR)

SCR is a post-combustion flue-gas treatment technology for reducing NO_X that involves injection of ammonia (NH_3), a reducing agent, into the flue gas downstream of the CT and then passing the gas through a catalyst bed. SCR is the most widely used post-combustion NO_X control technique on utility-scale CTs, usually in conjunction with combustion controls. It has been demonstrated to be able to achieve NO_X emission limits as low as 2.0 ppm and up to 90 percent reduction efficiency.[3]

Control of ammonia injection is an important parameter for an SCR system. Ammonia is injected in proportion to the amount of NO_X in the gas stream. A molar ratio of 1.0 to 1.3 is typically used, depending upon the degree of control and final effluent NO_X concentration required. NO_X is measured either upstream of the system (feed-forward controls) or downstream of the system (feedback controls), depending upon the supplier's system, and multiplied by a gas flow signal to adjust the ammonia injection rate. Some systems are equipped with an ammonia analyzer downstream of the SCR system so that escape of unreacted ammonia ("ammonia slip") can be monitored. These analyzers are usually part of a feedback control system that will reduce the ammonia injection rate in the event of unacceptable slip.

Sulfur content of the fuel can be a concern for systems that employ SCR. NTE will minimize concern by exclusively firing the proposed project's CT and DB with natural gas.

Further discussion is provided in the application.

5.2.2.6 EMxTM/SCONOX

Goal Line Environmental Technologies developed $SCONO_X$, which was developed to simultaneously remove NO_X, CO, VOC, and SO_X without supplemental reagent. The technology is currently licensed to EmeraChem Power and the current version of the technology is marketed as EMx^{TM}. EMx^{TM} uses a platinum-based catalyst coated with potassium carbonate to oxidize CO to CO_2 and NO to NO_2. NO_2 then absorbs onto the catalyst to form potassium nitrite and potassium nitrate. Periodically, the catalyst is regenerated with a proprietary (dilute hydrogen) gas that converts the compounds back to potassium carbonate, water and nitrogen. To maintain continuous operation, the system is divided into sections, with one section offline at all times for regeneration. The modules are separated by louvers. NO_X reduction in the system occurs in an operating temperature range of 300 of to 700°F, and, therefore, must be installed in the appropriate temperature section of a HRSG.

One advantage of the EMx™ process, compared to SCR, is that ammonia is not required. However, the EMx™ system catalyst is subject to reduced performance and deactivation due to exposure to sulfur oxides. For this reason, an additional catalytic oxidation/absorption system to remove sulfur compounds is installed upstream of the catalyst. The SO_2 is oxidized to sulfur trioxide (SO_3), which is then deposited on the catalyst. The SO_3 is removed from the catalyst when it is regenerated.

The technical feasibility and commercial availability of EMx^{TM} technology as BACT or LAER for large CT projects have been raised at numerous air permitting proceedings. The general conclusion has been that although EMx™ may have some advantage over SCR in being a zero ammonia NO_X reduction process, both SCR (combined with oxidation catalysts) and EMx™ are capable of achieving equivalent levels of controlled NO_X, CO, and VOC emissions. Other proceedings have concluded simply that EMx™ is not currently available for the size CT proposed for the proposed project. In addition, the cost impact of EMx™ is considered significantly higher than that for the combination of SCR and oxidation catalysts. Further discussion is provided in the application.

5.2.2.7 Selective Non-Catalytic Reduction (SNCR)

Selective non-catalytic reduction (SNCR): Selective non-catalytic reduction involves injection of ammonia or urea with proprietary conditioners into the exhaust gas stream without a catalyst. SNCR technology requires gas temperatures in the range of 1,600°F to 2,100°FI9[4] and is most commonly used in external combustion boilers. SNCR requires a temperature

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[3]See Appendix D for large combined-cycle CTs using SCR to achieve 2.0 ppmvd @ 15 percent O_2 permit limits.

[4] EPA Air Pollution Control Fact Sheet, EPA-452/F-03-031 (available at: http://www.epa.gov/ttn/catc/dir l/fsncr.pdf)

window that is higher than the exhaust temperatures from utility CT installations. The exhaust temperature from the proposed CTs ranges from approximately 1,030°F to 1,170°F; therefore, SNCR is not technically feasible in this application.

5.2.3 Elimination of Technically Infeasible Options (Step 2)

The technical feasibility of the identified available CT NO_X control options is summarized as follows:

- **Fuel Selection/Fuel-NO_X Control.** Exclusive use of natural gas is technically feasible for the proposed project, given its location in proximity to developing natural gas supply lines, and is being proposed. Higher NO_X emissions resulting from use of distillate oil as a backup fuel will be avoided through exclusive use of natural gas.
- **Water/Steam Injection.** Wet injection, although less effective for gas firing than other combustion systems (e.g., DLN combustors), is considered technically feasible; however, in modern combined-cycle units, wet injection is only used with oil firing, which is not proposed for the project. Because wet injection is not used in modern gas-fired combined- cycle units and since DLN combustors would provide an equivalent or higher level of control, wet injection is not carried forward for further analysis.
- **DLN Combustors**. DLN combustors are available, demonstrated, and technically feasible for CT units in either simple cycle or combined-cycle configurations. The CT proposed for the project utilizes DLN technology, controlling NO_X to a concentration of 20 ppmvd at 15% O_2 in the CT exhaust gas (before the SCR. As the proposed project will also be exclusively fired with natural gas, DLN will be used for all operating scenarios.
- **Catalytic Combustion.** While the KLean™ catalytic combustion system is applied directly to the CT, application on a large combined-cycle CT unit has not been demonstrated. All commercial installations to date have been on small turbines in the 1-2 MW size range. For this reason, the KLean™ technology is not considered available or technically feasible for the proposed project CT unit.
- **SCR.** SCR has been demonstrated successfully in numerous applications and is considered technically feasible for the proposed project's combined-cycle CT.
- **EMx™**. The EMx™ control technology is not considered available (and therefore is considered technically infeasible) since it has not been commercially demonstrated on large combined-cycle CT units.
- **SNCR.** Because the exhaust temperatures from the proposed combined-cycle units typically will not approach the operating temperature window for SNCR, this technology is not technically feasible for this application. The combustion turbine exhaust temperature is typically around 1,100°F, and the temperature at the exhaust stack downstream of the HRSG is expected to range between approximately 150°F and 290°F, which are 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 CTs. Based on the above limitations, SNCR is considered technically infeasible for application to the CT in this project.

Based on the preceding discussion, the following technologies are considered technically feasible and are carried forward for further analysis:

- Fuel Selection - exclusive natural gas;
- DLN Combustors; and
- SCR.

5.2.4 Ranking of Remaining Control Technologies (Step 3)

Exclusive natural gas use, DLN combustors, and SCR are compatible technologies and considered together, represent the best control strategy for NO_X emissions from large combined-cycle CTs. Therefore, a ranking is not required to establish the top technology.

5.2.5 Evaluation of Most Effective Controls (Step 4)

Based on EPA "top-down" BACT analysis guidance, analyses of economic, energy, and environmental impacts are only required if the "top" or most stringent control technology is not selected to determine if an option can be ruled out based on unreasonable impacts. The following summarizes the economic, energy, and environmental impact considerations associated with the combination of DLN and SCR for the Project CT:

- Economic Impacts. 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.[5]

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[5] U.S. EPA, document no. EPA-452/F-03-019: Air Pollution Control Technology Fact Sheet - Selective Catalytic Reduction (SCR), p. 2.

- Energy Impacts. 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 pressure drop across the catalyst, to supply hot dilution air for mixing with the NH_3, and to pump NH_3 into the vaporizer.
- Environmental Impacts. 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 the storage and use of $NH_{3,}$ which can cause environmental consequences if not handled and stored properly. NH_3 for the SCR can be in either liquid form or created from solid urea. If liquid NH_3 is used above certain thresholds, storage of this substance may trigger requirements as specified by the OSHA Process Safety Management regulations, the EPA Chemical Accident Prevention provisions and the EPA Community Right-to-Know Act. Much of these requirements are typically avoided by specifying aqueous NH_3 storage at concentrations less than 20 percent. NH_3 slip (i.e., unreacted NH_3 emitted from the stack) is typically 5 ppm or less but has the potential to increase with increasing NH_3 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 applicable regulations.

5.2.6 Selection of BACT and Determination of NOX Emission Limit (Step 5)

NTE proposes a combination of exclusive natural gas use, DLN combustors, and SCR to meet BACT requirements. These technologies, when considered together, represent the most stringent NO_X controls available for combined-cycle CTs. The proposed NO_X emission limits for all operating loads between 50 and 100 percent (for either turbine option), with or without duct firing in the HRSG are summarized below. NTE proposes to meet these limits on a 1-hour average basis. (A discussion of alternative limits during startup and shutdown events is provided in Section 5.8).

MHPSA M501GAC and Siemens SCC6-8000H (50 - 100 Percent Load)

NO_X	2.0 ppmvd @ 15% O_2 for all operating loads between 50 and 100 percent, w/out duct firing
	2.0 ppmvd @ 15% O_2 for all operating loads between 50 and 100 percent, w/ duct firing

Based on a review of LAER and BACT determinations in EPA's RBLC and permits for CTs not included in the RBLC, the 2.0 ppmvd @ 15% O_2 NO_X level has been identified as the most- stringent limit contained in a current air permit for a large combined-cycle CT. As the proposed NO_X emission limit is equivalent to the most stringent identified limit and is more stringent than applicable NSPS or North Carolina SIP limits for the same class or category of emission sources, it is sufficiently demonstrated as BACT.

The DAQ agrees with the proposed BACT emission limit via the use of SCR. Appropriate M/R/R will be incorporated into the permit. The Permittee will be required the meet the M/R/R requirements of NSPS Subpart KKKK (i.e., NOx and O2 CEMs). M/R/R will also be required to meet an ammonia slip limitation of 5 ppm via the use of second NOx CEMS with an NH3/NO converter.

5.3 BACT for CT CO

CO emissions from the proposed project are subject to BACT requirements (estimated potential emissions of CO will be greater than the 100 TPY PSD Significant Emission Rate). This section summarizes the BACT analysis conducted for CO.

5.3.1 Minimum CO Regulatory Requirements

There are no applicable NSPS, NESHAPs or North Carolina SIP requirements applicable to CO emissions from combined-cycle CTs.

5.3.2 Identification of Available CO Control Technologies (Step 1)

CO emissions are formed in CTs as a result of incomplete combustion of carbonaceous fuels. Similar to the generation of NO_X emissions, the primary factors influencing the generation of CO emissions are temperature and residence time within the combustion zone. Variations in fuel carbon content have relatively little effect on overall CO emissions. Providing adequate fuel residence time and high temperature in the combustion device to ensure complete combustion can minimize CO emissions. However, these combustion techniques can sometimes increase NO_X emissions. Conversely, a low NO_X emission rate achieved by flame temperature control can result in higher CO emissions. Therefore, a compromise must be reached whereby the flame temperature reduction is set to achieve the lowest NO_X emission rate possible while maintaining CO emission rates at acceptable levels.

There are two basic techniques for controlling CO emissions from combustion units: good combustion practices and post-combustion controls - installation of oxidation catalysts in the HRSG to oxidize CO to CO_2. Based upon a review of RBLC search results, existing permits for similar combined-cycle CTs, CT vendor information and technical literature, oxidation catalysts have been applied extensively over the last 10 years for CO control.

5.3.2.1 Combustion Controls

CO emissions are generated from the incomplete combustion of carbon in the fuel and organic compounds. Optimization of the combustion chamber designs and operation to improve the oxidation process and minimize incomplete combustion is the primary mechanism available for lowering CO emissions. This process is often referred to as combustion controls. Combustion controls in large CTs generally utilize "lean combustion" (large amount of excess air) to produce a cooler flame temperature to minimize NO_X formation, while still ensuring good air/fuel mixing with excess air to achieve complete combustion, thus minimizing CO emissions.

5.3.2.2 Oxidation Catalysts

Oxidation catalysts are a proven post-combustion control technology widely in use on large CTs to abate CO emissions. An oxidation catalyst oxidizes the CO in the exhaust gases to form CO_2. No supplementary reactant is necessary in conjunction with the catalyst for the oxidation reaction to proceed. Technical factors relating to this technology include the catalyst reactor design, optimum operating temperature, back pressure loss to the system, catalyst life, and potential collateral increases in emissions of PM_{10}, $PM_{2.5}$ and sulfuric acid mist emissions (from oxidation of SO_3 to SO_3, followed by conversion of SO_3 to H_2SO_4 in the presence of moisture). The oxidation catalyst is typically a precious metal catalyst. None of the catalyst components is considered toxic.

Oxidation catalysts have been employed successfully for two decades on natural gas-fired CTs. An oxidation catalyst is considered to be technically feasible for application to the proposed project. See application for further discussion.

5.3.2.3 EMxTM

The EMx^{TM} system previously described in Section 5.2.2.6 also controls CO. The EMx^{TM} system employs a single catalyst to simultaneously oxidize CO to CO_2 and NO to NO_2. The EMx^{TM} system operates at a temperature range of 300°F to 700°F and, therefore, must be installed in the appropriate temperature section of a HRSG.

5.3.3 Elimination of Technically Infeasible Options (Step 2)

The technical feasibility of the identified available CT CO control options is summarized as follows:

- **Combustion controls.** Combustion controls have been demonstrated successfully in numerous applications and are considered technically feasible for the proposed project's combined-cycle CT.
- **Oxidation Catalysts.** Catalytic oxidation has been demonstrated successfully in numerous applications and is considered technically feasible for the proposed project's combined- cycle CT.
- **EMx^{TM}.** As previously discussed in Section 5.2.3, the EMx^{TM} control technology is not considered available (and therefore is considered technically infeasible) because it has not been commercially demonstrated on large combined-cycle CT units.

Based on the preceding discussion, the following technologies are considered technically feasible and are carried forward for further analysis:

- Combustion controls; and
- Oxidation catalysts.

5.3.4 Ranking of Remaining Control Technologies (Step 3)

Combustion controls and catalytic oxidation are compatible technologies and considered together, represent the best control strategy for CO emissions from large combined-cycle CTs. Therefore, a ranking is not required to establish the top technology.

5.3.5 Evaluation of Most Effective Controls (Step 4)

Based on EPA "top-down" BACT analysis guidance, analyses of economic, energy, and environmental impacts is not required in this case where the "top" or most stringent control technology has been selected for CO.

5.3.6 Selection of BACT and Determination of CO Emission Limits (Step 5)

NTE proposes a combination of exclusive natural gas use, combustion controls, and oxidation catalysts to meet BACT requirements for CO. These technologies, when considered together, represent the most stringent CO controls available for combined-cycle CT. The proposed CO emission limits are summarized below for normal operating loads between 50 and 100 percent. NTE proposes to meet the CO limit on a 1-hour average basis (with CEMS). (A discussion of alternative limits during startup and shutdown events is provided in Section 5.8).

<u>MHPSA M501GAC and Siemens SCC6-8000H (50 - 100 Percent Load)</u>

CO	2.0 ppmvd @ 15% O_2 for all operating loads between 50 and 100 percent, w/out duct firing
	2.0 ppmvd @ 15% O_2 for all operating loads between 50 and 100 percent, w/ duct firing

Based on a review of BACT determinations in EPA's RBLC and permits for CTs not included in the RBLC, the majority of recent CO BACT determinations include combustion controls and oxidation catalysts.
The most recent permit for CPV Towantic contains a CO limit of 0.9 ppmvd @ 15% O2 w/o duct firing and 1.7 ppmvd @ 15% O2 w/duct firing. This facility was recently permitted and as such, there is insufficient long-term operating history at this time to support feasibility of a CO limit less than 2.0 ppmvd @ 15 percent O2 on a 1-hour averaging basis to consider it demonstrated in practice. The most stringent recent limits on projects that are in operation are 2.0 ppmvd @ 15 percent O_2 for CO. As the proposed CO emissions limits are equivalent to the most stringent identified limits that are considered achieved in practice, they are sufficiently demonstrated as BACT for the combined-cycle CT in this application.

The DAQ agrees with the proposed BACT limitation.

5.4 BACT Analysis for CT VOC

The proposed project will be subject to BACT for VOC, because estimated potential emissions of VOC will be greater than the 40 TPY PSD significant emission rate threshold applicable to VOC emissions for a major source. This section demonstrates that the proposed VOC emissions and controls meet the PSD BACT requirements.

5.4.1 Minimum VOC Regulatory Requirements

There are no applicable NSPS, NESHAPs or North Carolina SIP requirements applicable to VOC emissions from combined-cycle CTs.

5.4.2 Identification of Available VOC Control Technologies (Step 1)

VOC emissions are formed in CTs as a result of incomplete combustion of carbonaceous fuels. Similar to the generation of CO emissions, the primary factors influencing the generation of VOC emissions are temperature and residence time within the combustion zone. Variations in fuel carbon content have relatively little effect on overall VOC emissions. Providing adequate fuel residence time and high temperature in the combustion device to ensure complete combustion can minimize VOC emissions. However, these combustion techniques can sometimes increase NO_X emissions. Conversely, a low NO_X emission rate achieved by flame temperature control can result in higher VOC emissions. Therefore, a compromise must be reached whereby the flame temperature reduction is set to achieve the lowest NO_X emission rate possible while maintaining VOC emission rates at acceptable levels.

There are two basic techniques for controlling VOC emissions from combustion units: good combustion practices and post-combustion controls - installation of oxidation catalysts in the HRSG to oxidize VOC to CO_2. Based upon a review of RBLC search results, existing permits for similar combined-cycle CTs, CT vendor information and technical literature, oxidation catalysts have been applied extensively over the last 10 years, primarily for CO control, but also for VOC control.

5.4.2.1 Combustion Controls

VOC emissions are generated from the incomplete combustion of carbon in the fuel and organic compounds. Optimization of the combustion chamber designs and operation to improve the oxidation process and minimize incomplete combustion is the primary mechanism available for lowering VOC emissions. This process is often referred to as combustion controls. Combustion controls in large CTs generally utilize "lean combustion" (large amount of excess air) to produce a cooler flame temperature to minimize NO_X formation, while still ensuring good air/fuel mixing with excess air to achieve complete combustion, thus minimizing VOC emissions.

5.4.2.2 Oxidation Catalysts

Oxidation catalysts are a proven post-combustion control technology widely in use on large CTs to abate VOC emissions. An oxidation catalyst oxidizes the VOC in the exhaust gases to form CO_2. This technology has been discussed in Section 5.3.2.2 and has been specified as BACT for CO.

5.4.2.3 EMx™

The EMx™ system previously described in Section 5.2.2.6 also controls CO and VOC. The EMx ™ system employs a single catalyst to simultaneously oxidize CO and VOC to CO_2 and NO to NO_2. The EMx™ system operates at a temperature range of 300 to 700°F and, therefore, must be installed in the appropriate temperature section of a HRSG.

5.4.3 Elimination of Technically Infeasible Options (Step 2)

The technical feasibility of the identified available CT VOC control options is summarized as follows:

- **Combustion controls.** Combustion controls have been demonstrated successfully in numerous applications and is considered technically feasible for the proposed project's combined-cycle CT.
- **Oxidation Catalysts.** Catalytic oxidation has been demonstrated successfully in numerous applications and is considered technically feasible for the proposed project's combined- cycle CT.
- **EMx™.** As previously discussed in Section 5.2.3, the EMx™ control technology is not considered available (and therefore is considered technically infeasible) because it has not been commercially demonstrated on large combined-cycle CT units.

Based on the preceding discussion, the following technologies are considered technically feasible and are carried forward for further analysis:

- Combustion controls; and
- Oxidation catalysts.

5.4.4 Ranking of Remaining Control Technologies (Step 3)

Combustion controls and catalytic oxidation are compatible technologies and considered together, represent the best control strategy for VOC emissions from large combined-cycle CTs. Therefore, a ranking is not required to establish the top technology.

5.4.5 Evaluation of Most Effective Controls (Step 4)

Combustion controls and oxidation catalysts are compatible technologies and considered together, represent the best control strategy for VOC emissions from large combined-cycle CTs. Therefore, a ranking is not required to establish the top technology.

5.4.6 Selection of BACT and Determination of VOC Emission Limits (Step 5)

NTE proposes a combination of exclusive natural gas use, combustion controls, and oxidation catalysts to meet BACT requirements for VOC. These technologies, when considered together, represent the most stringent VOC controls available for combined-cycle CTs. The proposed VOC emission limits are summarized below for normal operating loads between 50 and 100 percent. NTE proposes to meet the VOC limit on a 3-hour average basis (stack test). (A discussion of alternative limits during startup and shutdown events is provided in Section 5.8).

<u>MHPSA M501GAC (50 -100 Percent Load)</u>

VOC	1.0 ppmvd @ 15 percent O_2 for all operating loads between 50 and 100 percent, w/out duct firing
	1.5 ppmvd @ 15 percent O_2 for all operating loads between 50 and 100 percent, w/ duct firing

<u>Siemens SCC6-8000H (50 -100 Percent Load)</u>

VOC	1.0 ppmvd @ 15 percent O_2 for all operating loads between 50 and 100 percent, w/out duct firing
	2.7 ppmvd @ 15 percent O_2 for all operating loads between 50 and 100 percent, w/ duct firing

Based on a review of LAER and BACT determinations in EPA's RBLC and permits for CTs not included in the RBLC, the majority of recent VOC BACT determinations include combustion controls and oxidation catalysts. The most stringent recent limits on projects <u>that are in operation</u> are approximately 1.0 ppmvd @ 15 percent O_2 for VOC without duct firing. Summaries of BACT determinations for VOC emissions from combined-cycle CTs permitted since 2010 are presented in Appendix D, Table D-3. A review of VOC permit limits indicates that the facilities typically have VOC limits at the 1 to 2 ppmvd @ 15% O_2 level without duct firing. The most recently permitted facilities are CPV Towantic and Mattawoman Energy, LLC, both of which have VOC emission limits of 1.0 ppmvd @ 15% O_2 without duct firing; and FGE Eagle Pines, LLC and Lon C. Hill Power Station, both of which have VOC emission limits of 2.0 ppmvd @ 15% O_2 without duct firing. However, two recently permitted projects (Brunswick Power and West Depford Energy) have VOC limits that are more stringent: The permitted VOC limits, corrected to 15% O_2 are 0.7 ppm, 3-hour average, for Brunswick Power and West Depford Energy without duct firing and 1.0 ppmvd @ 15% O_2 with duct firing. The Brunswick Power and West Depford Energy projects were permitted in 2013 and 2014 respectively and thus there is little long term operating history. As such, a VOC limit less than 1.0 ppmvd @ 15 percent O_2 (without duct firing) on a 3-hour averaging basis is not yet considered demonstrated in practice, due to insufficient operating history at that level.

A key reason that VOC emission limits with duct firing cannot typically be compared on an equivalent basis is because the VOC emissions input from duct firing will vary as a function of the duct burner heat input rate. For example, combined-cycle units with relatively large duct burner heat input relative to the CT will have higher uncontrolled VOC emissions and therefore, higher controlled emissions after the oxidation catalysts. The duct firing for the Siemens turbine option is much higher than for the MHPSA turbine option and thus uncontrolled VOC emissions are much higher. The oxidation catalysts are also much less effective at VOC control than CO control (typically 30 percent VOC control compared to 80+% CO control) and thus the controlled VOC emissions from the Siemens turbine option will be higher than the controlled VOC emissions from the MHPSA turbine option. Therefore, the 1.0 ppmvd @ 15% O_2 limit without duct firing (for both turbine options), 1.5 ppm @ 15% O_2 with duct firing (MHPSA), and 2.7 ppmvd @15% O_2 with duct firing (Siemens), based on a 3-hour averaging time (average of three 1-hour stack test runs) are considered the most stringent VOC limits achieved in practice for the proposed combined-cycle units.

The NC DAQ concurs with the proposed VOC BACT limitations considering the goals of BACT which takes "into account energy, environment, and economic impacts and other costs, determines is achievable... for control of such a pollutant." Appropriate M/R/R will be included in the permit to ensure appropriate operation of the oxidation catalyst. The M/R/R for catalyst for purposes of CO destruction will be used as a surrogate for VOC destruction. Annual VOC testing, with the option to reduce testing to once in every 5 years if the margin of compliance is less than 80 % of the BACT limit will also be included in the air permit.

5.5 BACT for CT Particulate Matter (PM/PM10/PM2.5)

Emissions of particulate matter (PM) from combustion occur as a result of inert solids contained in the fuel, unburned fuel hydrocarbons which agglomerate to form particles, and mineral matter in water that may be injected for NO_X control during diesel firing (not relevant for the project, which is based on exclusive natural gas combustion). PM is also theorized to come from dust particles in the ambient air drawn into the turbine's compressor, which then "pass through" and exit the stack. Although this re-entrained PM is not due to operation of the CT itself, it may be detected by the methods used for stack testing. The proposed project will utilize high-efficiency inlet air filters to avoid drawing particulates through the CT and out the stack.

PM emissions can also result from the formation of ammonium salts (sulfates and nitrates) due to the conversion of SO_2 to SO_3, which is then available to react with ammonia to form ammonium sulfate and NO_X, which may also react with ammonia to form ammonium nitrate salts. Ammonium salts are very fine particulate, typically in the sub-micron size range. In addition, as PM_{10} and $PM_{2.5}$ include both filterable and condensable fractions (front-half and back-half), condensable organics may also be measured as particulates. All of the PM emitted from the CT is conservatively assumed to be less than 2.5 microns in diameter. Therefore, PM_{10} and $PM_{2.5}$ emission rates are assumed to be the same.

The proposed project's PM, PM_{10} and $PM_{2.5}$ emissions are greater than the respective PSD significance thresholds and thus the PSD BACT requirements apply to PM, PM_{10} and $PM_{2.5}$ (see Section 4.3).

5.5.1 Minimum PM/PM10/PM2.5 Regulatory Requirements

There are no NSPS (Subpart KKKK) limits applicable to PM/PM/$_{10}$/$PM_{2.5}$ emissions from natural gas-fired combined-cycle CTs.

15A NCAC 02D .0503(c) limits emissions of PM from the combustion unit options (3,618 and 3,670 MMBtu/hr heat input for the MHPSA and Siemens options respectively) to no more than 0.2 lb/MMBtu heat input for either option. The project's CT will be subject to this limitation only during operation of the duct burner. However, the project will comply with the applicable standard by combusting pipeline quality natural gas (0.75 grains/100 SCF), which is estimated to result in a total PM emission rate less than 0.006 lb/MMBtu for either option with duct firing.

5.5.2 Identification of Available PM/PM10/PM2.5 Control Technologies (Step 1)

No add-on control technologies are listed in the RBLC listings for CTs. Proper combustion control and the firing of fuels with negligible or zero ash content and a low sulfur content are the only control methods identified for CTs. Clean fuels are necessary to avoid damaging turbine blades and other components already exposed to very high temperature and pressure. Natural gas is an inherently clean fuel and contains no ash. In addition, high-efficiency CT air inlet filters are typically specified to minimize PM being drawn in with CT air.

Add-on controls, such as electrostatic precipitators (ESPs) or baghouses, have never been applied to commercial CTs; however, they are considered available technologies, since they can be obtained through commercial channels. The feasibility of add-on controls is further evaluated in Section 5.5.3.

Controls identified as available for minimizing PM/PM/$_{10}$/$PM_{2.5}$ emissions from CTs are:

- Combustion control;
- Negligible or no-ash fuels (use of pipeline quality natural gas);
- Low sulfur fuels (use of pipeline quality natural gas);
- High-efficiency CT air inlet filters; and
- ESPs and baghouses.

5.5.3 Elimination of Technically Infeasible Options (Step 2)

Although considered available controls, ESPs and baghouses, have not been and cannot be installed and successfully operated on combustion turbine exhausts to achieve reductions in PM/PM_{10}/$PM_{2.5}$ emissions and, therefore, are not considered applicable or technically feasible. They are not applicable or technically feasible for CT applications for the following reasons:

1. The uncontrolled PM/PM_{10}/$PM_{2.5}$ concentrations in the CT/HRSG exhaust (for either option) are lower than the best level of control that ESPs and baghouses can achieve. e.g., the filterable PM/PM_{10}/$PM_{2.5}$ in the CT/HRSG exhaust,

based on the vendor performance data/guarantees are <0.0039 lb/MMBtu for either turbine option without duct firing.

2. The best performing ESPs and baghouses are capable of achieving a controlled filterable $PM/PM_{10}/PM_{2.5}$ emission rate in the range of 0.01 to 0.02 lb/MMBtu.
3. ESPs or baghouses would have no effect on the condensable fraction of the PM.

As add-on $PM/PM_{10}/PM_{2.5}$ controls are considered technically infeasible for combustion turbines, no further evaluation of the economic or energy impacts of those controls are required for the top- down BACT analysis.

Each of the remaining available CT PM control options identified in Section 5.5.2 are considered technically feasible.

5.5.4 Ranking of Remaining Control Technologies (Step 3)

Exclusive natural gas use, high-efficiency CT air inlet filters and DLN combustors are compatible technologies and considered together, represent the best control strategy for $PM/PM_{10}/PM_{2.5}$ emissions from large combined-cycle CTs. Therefore, a ranking is not required to establish the top technology.

5.5.5 Evaluation of Most Effective Controls (Step 4)

Based on EPA "top-down" BACT analysis guidance, analyses of economic, energy and environmental impacts is not required in this case as the "top" or most stringent control technology is selected for $PM/PM_{10}/PM_{2.5}$. Regardless, there are no potential energy, environmental, or economic impacts that would preclude the use of pipeline quality natural gas, high-efficiency air inlet filters and DLN in the combined-cycle CTs.

5.5.6 Selection of BACT and Determination of PM/PM10/PM2.5 Emission Limits (Step 5)

NTE proposes exclusive use of natural gas in the CT and DB, and high-efficiency air inlet filters to minimize emissions of $PM/PM_{10}/PM_{2.5}$, which represents the most stringent controls available for combined-cycle CTs. The proposed $PM/PM_{10}/PM_{2.5}$ emission limits are summarized below, applicable to all operating loads. NTE proposes to meet the limits based on fuel sulfur monitoring/fuel supplier certifications and initial stack testing, if necessary.

Sulfur content in natural gas	0.75 grains/100 SCF (enforceable through fuel supplier certifications/monitoring records)
$PM/PM_{10}/PM_{2.5}$ (filterable + condensable PM)	0.0039 lb/MMBtu (CT only/both turbines) 0.0053 lb/MMBtu (CT + DB/MHPSA) and 0.0051 lb/MMBtu (CT + DB/Siemens)

Based on a review of BACT determinations in EPA's RBLC and permits for CTs not included in the RBLC, as summarized in Appendix D, Table D-4, limits have been provided either lb/MMBtu or lbs/hr of $PM/PM_{10}/PM_{2.5}$. The BACT limits expressed as lb/MMBtu range from 0.0040 to 0.0088 which are all higher than the proposed BACT limits for either turbine options.

Limiting the amount of sulfur in the fuel also is a common practice for natural gas-fired power plants. The practical limitation is considered region-specific, depending on the source/specifications of the natural gas in the pipeline supplying the plant. For the proposed project, monitored sulfur concentrations over three years in the nearest Transco monitoring station (160) to the project site indicate a range of 0.01 to 0.7 grains/100 SCF with an average of 0.36 grains/100 SCF. However, to allow for future variations, and because natural gas originating in the northeast will be injected with odor compounds which could significantly increase the sulfur content, NTE is proposing a sulfur content limit of 0.75 grains/100 SCF. More stringent listed $PM/PM_{10}/PM_{2.5}$ emission limits in the RBLC are generally specific to projects with more stringent natural gas sulfur content specifications that are applicable to the geographic location of those projects. As $PM/PM_{10}/PM_{2.5}$ emissions are directly affected by fuel sulfur content, the applicable emissions limitations must also be linked to those specifications.

As the proposed $PM/PM_{10}/PM_{2.5}$ emissions limits are equivalent to the most stringent identified limits that are considered achieved in practice, given the maximum expected natural gas sulfur content, they are sufficiently demonstrated as BACT for the combined-cycle CT in this application.

The NC DAQ concurs with the proposed PM10/2.5 BACT limitations considering the goals of BACT which takes "into account energy, environment, and economic impacts and other costs, determines is achievable... for control of such a pollutant." Appropriate M/R/R will be included in the permit, which will require fuel sulfur monitoring via NSPS Subpart KKKK. Annual testing, with the option to reduce testing to once in every 5 years if the margin of compliance is less than 80 % of the BACT limit will also be included in the air permit.

5.6 BACT for CTs Sulfuric Acid (H_2SO_4)

SO_2 is generated during the combustion process as a result of the thermal oxidation of the sulfur contained in the fuel. While the SO_2 generally remains in a gaseous phase throughout the flue gas flow path, a small portion may be oxidized to SO_3. The SO_3 can subsequently combine with water vapor to form H_2SO_4. The project's SO_2 emissions are below the PSD significance threshold and thus the PSD BACT requirements do not apply to SO_2. Potential H_2SO_4 emissions from the project are estimated to exceed the PSD significance threshold for both turbine options and therefore, are subject to the PSD BACT requirements.

5.6.1 Minimum Sulfuric Acid Regulatory Requirements

There are no specific regulatory limits for H_2SO_4. However, compliance with applicable SO_2 standards limits H_2SO_4 emissions. The NSPS (Subpart KKKK) limits applicable to SO_2 emissions from natural gas-fired combined-cycle CTs are as follows:

- 0.9 lb/MWh gross output or
- 0.06 lb SO_2/MMBtu heat input.

15A NCAC 02D .0516 limits SO_2 emissions from any combustion unit to 2.3 lb/MMBtu of heat input.

The project will comply with the applicable standards for SO_2 by combusting pipeline quality natural gas. Using 0.75 grains sulfur/100 SCF sulfur content and approximately 1,020 Btu/ft3 (HHV) heat content for natural gas, the SO_2 emission rate for is estimated as 0.0021 lb/MMBtu.

5.6.2 Identification of Available Sulfuric Acid Control Technologies (Step 1)

Technologies generally employed to control H_2SO_4 mist emissions from combustion sources consist of fuel treatment and post-combustion add-on controls that rely on chemical reactions within the control device to reduce the concentration of SO_2 in the flue gas [also referred to as flue gas desulfurization (FGD) systems]. Based upon a review of RBLC search results, existing permits for similar combined-cycle CTs, CT vendor information and technical literature, post-combustion controls have not been applied to CTs. Minimization of SO_2 emissions has been achieved in practice through combustion of natural gas and ULSD backup fuel.

5.6.2.1 Fuel Treatment

Fuel treatment technologies are applied to gaseous, liquid, and solid fuels to reduce their sulfur contents prior to delivery to the end user. The fuel proposed for the project combined-cycle units is natural gas only. Desulfurization of natural gas is performed by the fuel supplier prior to distribution by pipeline. Based on specifications obtained from the gas supplier, NTE is proposing a natural gas sulfur limit of 0.75 grains/100 SCF.

5.6.2.2 Flue Gas Desulfurization (FGD)

FGD systems are post-combustion control technologies that rely on chemical reactions within the control device to reduce the concentration of SO2 in the flue gas. The chemical reaction with an alkaline chemical, which can be performed in a wet or dry contact system, converts the SO2 to sulfite or sulfate salts. FGD systems applied in practice to coal- and some oil-fired power plants (external combustion boilers) include wet scrubbers and dry scrubbers, such as spray dryer absorbers. FGD has not been applied to CTs.

5.6.3 Elimination of Technically Infeasible Options (Step 2)

The technical feasibility of the identified available CT sulfuric acid mist control options is summarized as follows:

- Fuel Treatment. The sulfur content in pipeline quality natural gas, which is treated by the fuel supplier prior to distribution, is already very low, and additional fuel treatment by the end user is considered technically infeasible.
- FGD. The removal efficiency of an FGD system decreases with decreasing inlet SO_2 concentration. FGD technology has been shown to function efficiently on emissions streams with relatively high uncontrolled sulfur levels (for example, for boilers firing high- sulfur coal). However, the SO_2 emissions from the proposed CT are two orders of magnitude lower than emission rates typically achievable using flue gas desulfurization. Moreover, there have been no applications of FGD technology to natural gas-fired combined-cycle units. As a result, the FGD technology is not considered to be technically feasible for combined-cycle CTs.

Based on the preceding discussion, the only technically-feasible option for H2SO4 carried forward for further analysis is fuel treatment/combustion of pipeline quality natural gas.

5.6.4 Ranking of Remaining Control Technologies (Step 3)

The use of pipeline quality natural gas is the only available and, therefore, top level of control for sulfuric acid mist. Therefore, a ranking is not required to establish the top technology.

5.6.5 Evaluation of Most Effective Controls (Step 4)

Based on EPA "top-down" BACT analysis guidance, analyses of economic, energy and environmental impacts is not required in this case as the "top" or most stringent control technology is selected for sulfuric acid mist. Regardless, there are no potential energy, environmental,or economic impacts that would preclude the use of pipeline quality natural gas in the combined- cycle CT.

5.6.6 Selection of BACT and Determination of H_2SO_4 Mist Emission Limits (Step 5)

NTE proposes exclusive use of natural gas in the CT and DB to minimize emissions of SO_2 and subsequently H_2SO_4 mist, which represents the most stringent H_2SO_4 control available for combined-cycle CTs. NTE proposes to meet the limits based on fuel sulfur monitoring/fuel supplier certifications.

Sulfur content in natural gas	0.75 grains/ 100 SCF (enforceable through fuel supplier certifications/monitoring records)

Limiting the amount of sulfur in the fuel is a common practice for natural gas-fired power plants. The practical limitation is considered region-specific, depending on the source/specifications of the natural gas in the pipeline supplying the plant. Based on a review of BACT determinations in EPA's RBLC, the most recent BACT determinations range from 2.1 to 4.6 lbs H_2SO_4/hr. The maximum emission rate for the Siemens turbine is 1.96 lbs/hr and the maximum emission rate for the Mitsubishi turbine is 4.35 lbs/hr. As mentioned previously, the engineering estimates vary significantly based on vendor estimates for the HRSG, SCR, and CO catalyst as well as with the sulfur content of the fuel. Review of three years of daily monitoring data from the nearest monitoring station provided by Transco (Station 160) indicates a mean of 0.3 grains/ 100 SCF. However historical monitoring data may not be reliable to predict future conditions (sulfur content may be higher) as the pipeline system begins flowing north to south, rather than south to north under existing conditions. In addition, natural gas in the northeast is injected with odor compounds which significantly increases the sulfur content. Due to this uncertainty, the project is proposing a sulfur content limit of 0.75 grains/I 00 SCF. More stringent H2SO4 mist emission limits in the RBLC are specific to projects with more stringent natural gas sulfur content specifications that are applicable to the geographic location of those projects. As H_2SO_4 mist formation is directly related to fuel sulfur content, the applicable emissions limitations must also be directly linked to those specifications.

Since numerical limits are a strong function of assumed SO2 to SO3 conversion, a numerical BACT limit will not be placed into the permit. The use of pipeline quality natural gas with an enforceable sulfur limit of 0.75 grains per 100 SCF is sufficient to meet the intent of BACT. The DAQ concurs with the proposed BACT limitation.

5.7 BACT for CT Greenhouse Gases (GHG)

The CT and DB will be fired exclusively with natural gas, which will emit three GHGs: methane (CH_4), carbon dioxide (CO_2), and nitrous oxide (N_2O). CH_4 is emitted from combustion devices burning natural gas as a result of incomplete combustion. Although CH_4 emissions can be reduced by operating the combustion devices at higher flame temperatures, higher excess oxygen levels, and increased residence time, these techniques for reducing CH_4 emissions can increase NO_X emissions. Consequently, achieving low CH_4 and NO_X emission rates is a balancing act in the combustor design and operation. CO_2 will be emitted from the combined-cycle CT because it is a combustion product of any carbon-containing fuel. However, relative to many other types of fossil fuel-fired power plants, natural gas combustion produces exhaust streams that are dilute in CO_2 concentration. Thus, as discussed in more detail below, full capture of CO_2 emissions from this plant is inefficient, challenging, and costly. N_2O will be emitted from the combined-cycle CT in trace quantities due to partial oxidation of nitrogen in the air used as the oxygen source for the combustion process and due to catalytic reduction reactions in the SCR systems used for NO_X control.[6]

5.7.1 Applicable GHG Regulatory Limits

EPA's New Source Performance Standards for fossil fuel-fired EGUs (40 CFR 60, Subpart TTTT) limit CO_2 emissions from new combustion turbines with design heat inputs to the turbine greater than 250 MW (850 MMBtu/hr) to 1,000 pounds CO_{2e}/MWh of electricity generated on a gross basis on a 12-operating month rolling average. This limit is based on the level of reduction achieved by the best system of emissions reduction EPA determines to have been adequately demonstrated for this type of unit. 80 Fed. Reg. 64510, 64512 (Oct. 23, 2015).

5.7.2 Identification of GHG Control Technologies (Step 1)

The potentially available control technologies for CH_4 emissions from a combined-cycle CT fired with natural gas are the same as those discussed with respect to CO and VOC emissions in Section 5.3.2:

- Good Combustion Practices;
- EMx™; and
- Oxidation Catalyst.

Each of these technologies, as discussed below, is designed to oxidize CH_4 and other carbon- containing compounds in fuel to form CO_2. This is beneficial from a GHG reduction standpoint because CO_2 is a much less potent GHG than CH_4 (CH_4 has 21

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[6] See, for example, EPA Air Pollution Control Cost Manual. 6th Ed. EPA-452/B-02-001. Section 4.2, Chapter 2, "Selective Catalytic Reduction." U.S. EPA. October 2000.

times the global warming potential of CO_2). Therefore, each of the identified CH_4 control options are considered as providing beneficial environmental impacts through oxidation of CH_4 and other carbon-containing compounds in fuel to form CO_2.

The potentially available control technologies for CO_2 emissions from combined-cycle CTs fired with natural gas are:

- Energy-efficient design in order to minimize the amount of fuel combusted;
- Use of low-carbon fuels in order to minimize the formation of CO_2 from fuel combustion; and
- Carbon capture and storage (CCS).

The only identified control technologies for the control of N_2O from combined-cycle CTs are aggressive energy-efficient design, in order to minimize the amount of fuel combusted, and elimination of SCR.

5.7.2.1 Good Combustion Practices

Good combustion practices for a combined-cycle CT fired with natural gas include the following:

- Good air/fuel mixing in the combustion zone;
- Sufficient residence time to complete combustion;
- Proper fuel gas supply system design and operation in order to minimize fluctuations in fuel gas quality;
- Good burner maintenance and operation practices;
- High temperatures and low oxygen levels in the primary combustion zone; and
- Overall excess oxygen levels high enough to complete combustion while maximizing thermal efficiency.

As with other types of fossil fuel-fired systems, combustion control is the most effective means for reducing CH_4 emissions. Combustion efficiency is related to the three "T's" of combustion:

Time, Temperature, and Turbulence. These components of combustion efficiency are designed into the combined-cycle CT to maximize fuel efficiency and reduce operating costs. Therefore, combustion control is accomplished primarily through unit design and operation.

Changes in excess air affect the availability of oxygen and combustion efficiency. Very low or very high excess air levels will result in relatively high CH_4 levels and can also affect NO_X formation. Increased excess air levels will reduce the emissions of CH_4 up to the point that so much excess air is introduced that the overall combustion temperatures begin to drop significantly. If combustion temperatures drop significantly, then unit efficiency is negatively affected. Low excess air levels lower combustion temperatures and do not allow sufficient oxygen to allow efficient combustion of $CH_{4,}$ but do reduce the formation of thermal NO_X. CTs and HRSGs operate within a narrow range of excess air levels due to the interrelationships between oxygen levels, combustion efficiency, formation of NO_X and products of incomplete combustion such as CH_4.

5.7.2.2 Oxidation Catalyst

As discussed in Section 5.3.2.2, oxidation catalysts have been widely applied as a control technology for CO and VOC emissions from natural gas-fired combined cycle CTs and would also provide reduction in CH_4 emissions. This technology utilizes excess air present in the combustion exhaust, and the activation energy required for the reaction to proceed is lowered in the presence of a catalyst. Reactants are introduced into a catalytic bed, with the optimum temperature range for these systems being approximately 850° F to 1,100° F. No chemical reagent addition is required.

5.7.2.3 EMxTM

EMx™ was evaluated as part of the NO_X and CO/VOC BACT analyses for the CT in Sections 5.3 and 5.4 and was eliminated as technically infeasible for the class of CT proposed for the Project. No further evaluation of EMx™ is presented here for the GHG BACT analysis.

5.7.2.4 Low-Carbon Fuel

Table 5-2 presents the amount of CO_2 formed when combusting fossil fuels, including natural gas.

Table 5-2 CO_2 Emission Factors for Fossil Fuels

Fuel	Pounds CO_2 per MMBtu
Coal	225[1]
Residual Oil	210[1]
Diesel	157[2]
Natural Gas	110[2]

(1) U.S. Energy Information Administration at http://www.eia.gov/oiaf/1605/coefficients.html.
(2) EPA, AP-42, Compilation of Air Pollutant Emission Factors

As shown in this table, use of natural gas reduces the production of CO_2 during the combustion process relative to burning other fossil fuels.

5.7.2.5 Energy Efficient Design

A highly-efficient combined-cycle power plant reduces the amount of fuel used to produce heat and electrical power. This reduction in fuel corresponds directly to the amount of GHG produced. Elements of a highly energy-efficient design for the combined-cycle power plant will include continuous excess air monitoring and control. Excessive amounts of combustion air in the HRSG result in energy-inefficient operation because more fuel combustion is required in order to heat the excess air to combustion temperatures. This can be alleviated using state-of-the-art instrumentation for monitoring and controlling the excess air levels in the combustion process, which reduces the heat input by minimizing the amount of combustion air needed for safe and efficient combustion. This requires the installation of an oxygen monitor in the stack and damper controls on the combustion air dampers. Additionally, lowering excess air levels, while maintaining good combustion, reduces not only GHG emissions but also NO_X emissions. Both CT options will be equipped with oxygen monitors as part of the continuous emission monitoring system.

A potentially higher efficiency combined-cycle design could include a solar hybrid facility, such as the Florida Power & Light's Martin Next Generation Solar Energy Center (FPL Martin) or the Palmdale Hybrid Power Project (PHPP), permitted in Florida and California, respectively. These projects consist of a hybrid of natural gas-fired combined-cycle generating equipment integrated with solar thermal generating equipment. The FPL Martin project, the first hybrid combined cycle natural gas + concentrating solar power plant to be developed in the United States, is constructed on an approximately 300-acre site in south Florida and the PHPP will be developed on an approximately 377-acre site in Palmdale, California.

However, including a solar hybrid facility of the scale proposed for the proposed project would require significantly greater land for the solar components, more consistent solar resources than available in the North Carolina and would result in significant visual impacts. Therefore, a solar hybrid facility would not be feasible and was not considered further in this GHG BACT analysis.

5.7.2.6 Carbon Capture and Storage (CCS)

CCS can be used to reduce atmospheric emissions of CO2 from CTs. To provide effective reduction of GHG emissions, CO2 must be captured and compressed, transported, and stored. CO2 emissions from combustion sources can theoretically 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. 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.

CCS is not technically feasible for the REC, for several reasons.

First, capture of CO2 emissions from a combined-cycle CT is not technically feasible. The pre-combustion technique for CO2 separation involves substituting pure oxygen for air in the combustion process. This “oxyfuel” process has not yet been tested or demonstrated in a large scale facility.[7] Accordingly, CCS involving pre-combustion CO_2 separation and capture is not technically feasible for the combined-cycle CT. Post-combustion capture is also not practical because the inherent design of the combined-cycle CT will produce relatively dilute (less than 5%) CO_2 streams, making separation of CO_2 from other exhaust gas constituents (i.e., "capture") difficult and costly.

[7] Strategies for the Commercialization and Development of Greenhouse Gas Intensity-Reducing Technologies and Practices, January 2009; http://www.climatetechnology.gov/Strategy-lntensity-Reducing-Technologies.pdf

Second, the lack of any storage facilities within a reasonable distance of the REC also make CCS not feasible. Geological storage in a saline formation in which substantial characterization and successful testing has already occurred is assumed to represent the best option for long-term storage. The closest known location with these attributes is at the Citronelle Oil Field in Mobile County, Alabama, where a demonstration project is injecting 0.25 million tons per year. The use of depleted oil and gas reservoirs with enhanced oil recovery (EOR) offers the potential to offset a portion of CCS costs through the sale of CO_2. However, EOR as it is currently practiced does not qualify as CO_2 storage, because it uses Class II wells that are not compliant with 40 CFR 98 Subpart RR, and the permanence of CO_2 storage in EOR applications has not been demonstrated.

Finally, there is no nearby pipeline infrastructure that could transport captured CO_2 from the REC to a remote location. The nearest CO_2 pipelines to North Carolina (existing or planned) are in southern Mississippi and southern Louisiana.[8]

For these reasons, CCS is not considered to be a technically feasible option for controlling CO_2 emissions at REC.

Although further consideration of CCS is not required in this BACT analysis because CCS is not technically feasible at REC, the deployment of CCS at this 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. The costs of deploying and maintaining a CCS system, as well as building infrastructure to transport captured CO_2 to the nearest available storage location would also be extraordinarily high. Those adverse effects are discussed in further detail in the PSD permit application for KMEC.

5.7.3 Elimination of Technical Infeasible Options (Step 2)

The technical feasibility of the identified available CT GHG control options is summarized as follows:

- Good Combustion Practices. Good combustion practices, as described herein, are technically feasible and are inherent in the design of the proposed Project's combined- cycle CT.
- Oxidation Catalysts. Catalytic oxidation has been demonstrated successfully in numerous applications and is already included in the proposed project's combined-cycle CT for CO and VOC control.
- EMx™. As previously discussed in Section 5.2.3, the EMx™ control technology is not considered available (and therefore is considered technically infeasible) since it has not been commercially demonstrated on large combined-cycle CT units.
- Low-Carbon Fuels. The combined-cycle CT will be exclusively fueled with low-carbon natural gas. There are no other control options involving the use of low-carbon fuels in these units that represent technically-feasible options for reducing GHG emissions relative to the proposed fuel.
- Energy Efficiency. Using solar thermal hybrid technology as an energy efficiency measure at the Project would not be feasible for the reasons stated above. However, each of the other identified strategies for energy-efficient design is technically feasible and is inherent in the design of the combined-cycle CT.
- Carbon Capture and Storage. CCS is not technically feasible for REC, for the reasons discussed above.
- Eliminating SCR. Elimination of SCR from the design of the combined-cycle CT at the proposed project is technically feasible and would be expected to result in lower N_2O emission rates. However, there would be the associated significant increase in NO_X emissions.

Based on the preceding discussion, the following technologies are considered technically feasible and are carried forward for further analysis:

- Good combustion practices;
- Oxidation catalysts;
- Low-carbon fuel;
- Energy efficiency;
- Post-combustion CCS (assumed to be feasible for purposes of BACT analysis); and
- Eliminating SCR.

5.7.4 Ranking of Remaining Controls (Step 3)

The use of good combustion practices, oxidation catalyst, low-carbon fuels, and energy-efficient design to reduce GHG emissions from combined-cycle CT is inherent in the design of the proposed project. The combination of these controls is considered the baseline condition. There are no technically feasible strategies for further controlling CO_2 emissions from the combined-cycle CT. The only technical feasible option for reducing N_2O emissions is the elimination of SCR.

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[8] EPA/DOE, Report of the Interagency Task Force on Carbon Capture and Storage, Figure B-1, Select CO_2 Sources and CO_2 Pipelines by Company, August 2010; 80 Fed. Reg. 64577.

No data are available to quantify the effect of SCR on N_2O formation in CT exhaust gas. For the purposes of the following analysis, it is conservatively assumed that 100 percent control of N_2O emissions would be achieved by eliminating SCR from the design of the Project. This control option is therefore assumed for the purposes of the following analysis to be capable of achieving a GHG emission reduction of approximately 14,167 to 14,304 tons CO_{2e} per year.

5.7.5 Evaluation of Most Effective Controls (Step 4)

Use of SCR to achieve controlled NO_X emissions of 2.0 ppmvd @ 15% O_2 is proposed as BACT for the combined-cycle CT options. Elimination of the SCRs would result in an increase in allowable NO_X emissions of approximately 1,034 tons per year (based on 90 percent NO_X reduction in the SCRs) from the CT. This increase significantly outweighs the reduction in N_2O emissions that could be achieved by eliminating the SCRs and would likely result in violations of the NO_2 ambient air quality standards. NTE considers this to be an unacceptable, adverse environmental impact. Elimination of SCR, therefore, does not represent BACT for GHG emissions.

5.7.6 Selection of BACT for CT GHG

Based on the GHG BACT analysis, the following technologies are proposed as BACT for the Project:

- Good combustion practices;
- Oxidation catalysts;
- Low-carbon fuel; and
- Energy efficiency/combined-cycle power plant.

The environmental, energy and economic impacts of post-combustion CCS were determined to be unreasonable for the proposed project. For the remaining technically feasible option, elimination of the SCRs to avoid N_2O formation, the environmental impact from the increase in NO_X emissions was determined to significantly outweigh the benefit from reduction in N_2O emissions.

NTE is proposing the following GHG BACT limitations which incorporate reasonable compliance margins for purposes of establishing a permit condition that can be practically enforced and based on the vendor data provided in the application

- Gross heat rate, new and clean (initial test), at ISO conditions with no duct firing not to exceed the following limit:
  MHPSA: 6,590 Btu/kW-hr, HHV (gross); equivalent to 783 lb CO2e/MWh)
  Siemens: 6,470 Btu/kW-hr, HHV (gross); equivalent to 745 lb CO2e/MWh)
- Gross heat rate, life of the facility (assumes 4.2% degradation), at ISO conditions with no duct firing not to exceed the following limits:
  MHPSA: 6,867 Btu/kW-hr, HHV (gross)
  Siemens: 6,742 Btu/kW-hr, HHV (gross)
- Total GHG on a CO_{2e} basis from the combined-cycle CT unit with duct firing will not exceed the following limit which includes startup, shutdown, commissioning and tuning: (See discussions in Section 5.9. below)
  MHPSA: 1,757,319 TPY
  Siemens: 1,782,510 TPY

These proposed BACT emission limits for GHG in units of lb CO2e/MWh are equivalent 783 and 745 lb CO2e/MW-hr (gross/new and clean) for the MHPSA and Siemens CT, respectively.[9] These rates are more stringent than other recent determinations as seen in Table 5-3 below.

N_2O and CH_4 components of CO_{2e} will be calculated by monitoring fuel use and using fuel-specific emission factors (e.g., AP-42 Table 3.1-2a) or site-specific factors determined through initial stack testing. The Permittee shall install, certify, operate and maintain a CO2 CEMS or determine its CO2 emissions according to 40 CFR Part 75 Appendix G.

A summary of recent GHG BACT determinations for combined-cycle power plants obtained from the RBLC and from review of other permits not in the RBLC is provided in Appendix D, Table D-5. Direct comparison of NTE's proposed BACT limits is complicated by inconsistencies in the bases used to establish GHG BACT limits. For example, some of the heat rate (Btu/kW-hr) and output-based limits (lb CO_2/MW-hr) limits are provided on a gross basis and others are provided on a net basis. Furthermore, design performance and degradation factors that are used to adjust the base heat rates that are based on vendor

[9] Note that "gross" output is based on the full electric energy output of the generation equipment, without consideration of internal plant loads (parasitic losses such as for pumps and fans). Net energy is based on the amount of electric energy after internal plant demand is satisfied, and reflects the amount of energy actually sold to the electric grid.

design data to realistic long-term values vary from permit to permit. From review of available permit applications and documentation on BACT determinations, the total allowances for these factors generally varies between about 8 and 14 percent. The inconsistency of units and basis of limits make it difficult to directly compare BACT determinations.

A summary of recent GHG BACT determinations for combined-cycle power plants obtained from the RBLC and from review of other permits not in the RBLC is provided in Appendix D, table D-5. Direct comparison of NTE's proposed BACT limits is complicated by inconsistencies in the bases used to establish GHG BACT limits. A summary of recent BACT determinations is provided below in Table 5-3.

Table 5-3 Summary of Recent BACT Determinations for GHG

Project/Date of Permit	**BACT Determination (lbs CO_2/MWh)**
CPV Towantic/November 30, 2015	809
Mattawoman Energy, LLC/November 13, 2015	865
FGE Eagle Pines, LLC/November 4, 2015	886
NRG Texas Power/September 15, 2015	825

It should be noted that the proposed BACT limits for CO_2 emissions from either CT option would comply with the standards in 40 CFR 60, Subpart TTTT which are GHG emissions of 1,000 lb/MWh of gross output applicable to CT power plants on a 12-month rolling average basis.

The DAQ agrees with the proposed BACT limitations. Annual heat rate testing, will be included in the air permit.

5.8 BACT for CT Ammonia (NH3) Slip Emissions

NH3 is not a regulated air pollutant under the federal PSD program. Although it is sometimes considered a potential PM2.5 precursor pollutant, pursuant to NCs PSD rule at 15A NCAC 02D .0530(b)(4):

Particulate matter PM2.5 significant levels in 40 CFR 51.166(b)(23)(i) are incorporated by reference except as otherwise provided in this Rule. Sulfur dioxide (SO2) and nitrogen oxides (NOx) are precursors to PM2.5 in all attainment and unclassifiable areas. <u>Volatile organic compounds and ammonia are not significant precursors to PM2.5.</u>

As such no BACT analysis or limits are required. However, ammonia slip limits will be placed into the permit (5 ppm @ 15 O2) to ensure proper operation of the SCR for NOx control and to minimize ambient impacts (see the NC Air Toxics rule 15A NCAC 02D .1100 discussion elsewhere).

5.9 Secondary BACT for CT Startups/Shutdowns, Combustor Tuning and Commissioning

5.9.1 Secondary BACT for CT Startups and Shutdowns

The primary BACT emission limits discussed in earlier sections are either rate-based limits based on the combined-cycle CT heat input (lb/MMBtu) or concentration-based limits based on flue gas flow rate (ppmvd @ 15% O_2). These limits reflect expected achievable emission rates using the respective control technology during periods of normal steady-state combined-cycle CT operation (between 50 and 100 percent load). However, these emission limits are not appropriate during periods of startup and shutdown. In these situations, the combustors do not operate at their maximum efficiency and, for CO, NO_X, and VOC, emission concentrations are increased due to lower fuel input and exhaust flow. In addition, SCR and oxidation catalysts are not effective because the exhaust temperatures are generally too low to achieve effective control. Furthermore, until the turbine reaches DLN mode, it emits at a higher rate. This makes it impossible for the combined-cycle CTs to comply with stringent BACT limits applicable to steady-state operation during startup and shutdown periods.

The definition of BACT in EPA regulations states that a BACT limit must be "achievable" on a case-by-case basis. Therefore, in order for NTE to propose limits that are both "achievable" and keep the combined-cycle CT under a high degree of control during normal steady-state operation, BACT limits applicable to normal steady state operations must not be applied to periods of startup and shutdown.

Permitting of separate secondary BACT limits is consistent with what has been proposed and accepted by other power generating facilities. The most recent and relevant examples for the proposed project are the Mattawoman Energy and Keys Energy facilities, both of which were permitted in the last two years. Secondary BACT limits are justified and, in cases such as CTs, are required to ensure with a necessary degree of confidence that the stringent primary BACT limits proposed in the previous sections are achievable for those pollutants with continuous compliance demonstration methods.

NTE is proposing secondary NO_X, CO, and VOC limits for startup and shutdown events that are mass-based limits on a pounds per year basis. This is consistent with the above-referenced Mattawoman and Keys Energy facilities. The pounds per year emissions limits are based on worst-case assumptions as to the numbers and types of startups and shutdowns for different operating scenarios (see Section 3.0 for discussion of methodology and estimates of total annual emissions) and CT vendor data on the durations and estimated emissions rates per startup/shutdown event. Compliance with these limits will be determined via CEMS for NO_X and CO. For VOC, compliance will be determined by calculation (based on correlation between CO and VOC emissions developed from initial performance/diagnostic testing) and recordkeeping.

In addition, worst-case estimates of the pounds per event and duration of startups/shutdowns, based on vendor data, will be included in the air quality modeling analysis to be submitted with Volume II of this application. Three different startup scenarios (cold, warm, and hot) are included as well as one shutdown scenario. Based on the project operating scenarios discussed in Section 3 and detailed in calculations provided in Appendix B, worst-case annual potential emissions have also been estimated based on different operating scenarios, including the numbers of each type of startup and shutdown. However, the number of each type of startup and shutdown is not proposed as a permit condition as these may vary. The proposed secondary BACT limits are instead mass-based limits that cap the total allowable emissions from all operating events. The proposed annual limits are provided in Tables 5-4 and 5-5. In addition, NTE proposes a limit of 500 hours of startup/shutdown operations per year for the CT. Note that the annual limits are very different for the MHPSA and Siemens turbine options and reflect the different methods used to bring the turbines to the level at which compliance with the proposed BACT emission limits is achieved.

Table 5-4 Proposed Potential Annual Pollutant Emissions from CT+DB/MHPSA

	MHPSA M501GAC - Total Annual Emissions for CT+DB			
Pollutant	**Case A**	**Case B**	**Case C**	**Max.**
NO_X	65.6	111.7	119.1	119.1
CO	280.3	147.8	72.3	280.3
VOC	100.4	57.0	31.1	100.4
$PM_{10}/PM_{2.5}$	39.9	75.4	82.3	82.3
SO2*	15.2	28.7	31.3	31.3
H2SO4	14.7	27.7	30.3	30.3
CO_2	856,294	1,610,165	1,757,319	**1,757,319**

* not subject to BACT restrictions, included for comparison purposes

Table 5-5 Proposed Potential Annual Pollutant Emissions from CT+DB/Siemens

	Siemens SCC6-8000H - Total Annual Emissions for CT+DB			
Pollutant	**Case A**	**Case B**	**Case C**	**Max.**
NO_X	75.8	119.4	120.9	120.9
CO	98.1	86.2	73.6	98.1
VOC	37.3	54.3	56.1	56.1
$PM_{10}/PM_{2.5}$	41.0	76.3	83.2	83.2
SO2*	16.6	31.0	33.8	33.8
H2SO4	6.4	11.9	12.9	12.9
CO_2	874,905	1,634,057	1,782,510	**1,782,510**

* not subject to BACT restrictions, included for comparison purposes

5.9.2 Combustor Tuning

Combustor tuning is required to maintain the CT in optimal operating condition. Tuning is performed periodically in response to turbine wear and variations in fuel, temperature, and humidity. The CT will be subject to stringent limits for startups and shutdowns in addition to stringent steady-state limits, so providing an allowance for tuning with alternative limits is necessary to assure compliance during the rest of the year.

Tuning involves testing and adjusting the different combustor operating modes and the transition from one mode to another. These operations are time-intensive and are expected to take up to 8 hours to complete each time. The tuning duration is due to the fact that the CT operating rate during the tuning is brought up slowly, approximately 5 MW at a time, and tuning is performed at each MW level. The CT is held at each load level while settings are varied to establish the optimal operating conditions. The complexity of the model-based control system requires tuning the CT at each operating point, which establishes tuning set points. The tuning set points are then saved in the plant control system algorithms and used during normal operation as the CT continuously and automatically tunes itself. Tuning would need to be performed up to two times per year.

Tuning has traditionally been performed during cold startups. Cold startups involve bringing the CT load up slowly and, therefore, provide an appropriate opportunity to conduct tuning. Recently, regulatory agencies have started imposing shorter time limits on cold startups, and so it has become increasingly difficult for operators to complete tuning within their cold startup time limits. Recent permits have, therefore, had to include specific provisions allowing for tuning operations outside of cold startups. Because tuning operations were originally conducted under cold startup limits, these provisions have typically provided for tuning operations to be subject to the same emissions limits applicable during cold startups. These limits are also generally appropriate for tuning because tuning involves low-load operation where emissions controls are not as effective, as is the case with cold startups. (Tuning takes longer than cold startups, however, because the CTs must be kept at each load level for a period of time while tuning takes place, and cannot be ramped up as soon as equipment conditions allow.)

NTE is proposing that tuning operations should be subject to alternative emissions limits initially the same as the hourly emissions limits that apply during cold startups - pounds per cold startup event divided by duration of startup. However, as the proposed project has not yet been built and there is insufficient operating data on which to base permit limits, NTE is further proposing that emissions limits for tuning operations would be established after the facility is built based on test data obtained during actual tuning operations.

NTE is therefore proposing as secondary BACT a provision that would allow for two tuning events to be conducted per year, with duration not to exceed 8 hours per tuning event. Emissions would be subject to the lowest limits that can be achieved by the project, which would establish based on testing after the project is built.

The DAQ agrees with the proposed BACT with the exception that emissions from the tuning operations will be incorporated into a single annual GHG limit for <u>startup, shutdown, commissioning, tuning and normal operations.</u>

5.10 Secondary BACT for CT Commissioning

The combined-cycle CT and associated equipment is highly complex and must be carefully tested, adjusted, tuned, and calibrated after the facility is constructed. These activities are generally referred to as "commissioning" of the facility. During the commissioning period, the CT needs to be fine-tuned at zero load, partial load, and full load to optimize its performance. The DLN combustors also need to be tuned to ensure that the CT runs efficiently while meeting both the performance guarantees and emission guarantees. In addition, the SCR systems and oxidation catalysts need to be installed and tuned.

The combined-cycle CT will not be able to meet the stringent BACT limits for steady-state operations during the commissioning period for a number of reasons. First, the SCR system and oxidation catalyst cannot be installed immediately when the CT is initially started up. There may be oils or lubricants in the equipment from the manufacture and installation of the equipment that would damage the catalysts if they were installed immediately. Instead, the CT needs to be operated without the SCR system and oxidation catalysts for a period of time to burn off any impurities that may be left in the equipment. In addition, once all of the pollution control equipment is installed, it needs to be tuned in order to achieve optimum emissions performance. Until the equipment is tuned, it will not be able to achieve the very high levels of emissions reductions reflected in the stringent BACT limits for normal operations.
Because the BACT limits established for normal operations are not technically feasible during the commissioning period, these limits are not BACT for this phase of the project's operation. Alternate limits must, therefore, be specified for this mode of operation.

The only control technology available for limiting emissions during commissioning is to use best work practices to minimize emissions as much as possible during commissioning, and to expedite the commissioning process so that compliance with the stringent BACT limits for normal operations can be achieved as quickly as possible. There are no add-on control devices or other technologies that can be installed for commissioning activities.

To implement best work practices as an enforceable requirement, NTE is proposing conditions that will require the operators to minimize CT emissions to the greatest extent possible during commissioning. Commissioning emissions will also be subject to the annual emissions limits applicable to normal operations. All emissions from commissioning activities will be counted towards the facility's annual limits. Because commissioning is a relatively short-term period, it is expected that project emissions will stay within those limits over the course of the entire year. Counting commissioning emissions towards the annual limits will also provide an additional incentive for the project operator to minimize emissions as much as possible. Compliance with these proposed conditions for the commissioning period will be monitored by monitoring fuel use and calculating emissions.

The DAQ agrees with the proposed BACT. The emissions from the tuning operations will be incorporated into a single annual GHG limit for <u>startup, shutdown, commissioning, tuning and normal operations.</u>

5.11 BACT for Emergency Generator and Fire Pump Diesel Engines

The project will include a maximum 1,675 bhp diesel engine powered emergency generator and a maximum 260 bhp diesel engine powered fire pump. Both diesel engines will be run on ULSD, with a maximum sulfur content of 0.0015 weight percent (15 ppmw). The engines will operate for maintenance and testing purposes and during actual emergencies. Operation of the emergency generator and the fire pump engine will each be limited to 100 hours per year for maintenance checks and readiness testing purposes (i.e., not including actual emergencies). Combustion of the ULSD will yield emissions of NO_X, SO_2,

$PM_{10}/PM_{2.5}$, CO, and VOC. The fire pump and the emergency generator will meet the emission requirements in EPA's Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (40 CFR Part 60 Subpart IIII).

The following table (excerpted from the application) summarizes the emission rates for these engines. Potential annual emissions are based on 500 hours of operation per year but will be limited to 100 hours per year of non-emergency operation. It will be shown that the appropriate BACT for these small sources is the implementation of good combustion practices, the combustion of ultralow sulfur fuel (less than 15 ppm sulfur) and the proper operation and maintenance of NSPS Subpart IIII compliant emergency-service engines.

Table 3-10 Potential Emissions for Diesel Engine Generator and Fire Pump

Diesel Engine Generator		
Pollutant	**Emissions (lbs/hr)**	**Emissions (tons/yr)**
NO_X	17.37	4.34
CO	2.92	0.73
VOC	0.33	0.08
$PM_{10}/PM_{2.5}$	0.15	0.04
SO_2	0.02	0.005
H_2SO_4	0.003	0.0007
NH_3	0.61	0.15
Lead	1.10E-04	2.70E-05
GHG	1,944	486
Total HAPs	0.02	0.006
Highest HAP (Benzene)	0.01	0.003

300 HP Diesel Fire Pump		
Pollutant	**Emissions (lbs/hr)**	**Emissions (tons/yr)**
NO_X	1.79	0.45
CO	0.26	0.07
VOC	0.07	0.02
$PM_{10}/PM_{2.5}$	0.05	0.01
SO_2	0.003	0.0008
H_2SO_4	0.0005	0.00012
NH_3	0.10	0.02
Lead	1.90E-05	4.80E-06
GHG	345	86
Total HAPs	0.008	0.002
Highest HAP (Formaldehyde)	0.002	0.0006

5.11.1 Emergency Diesel Engine NOX BACT

5.11.1.1 Identification of NOX Control Technologies (Step 1)

There are a limited number of available control technologies for diesel internal combustion engines used for limited or emergency operations. Potentially available control options for reducing NO_X emissions from diesel engine emergency generators and fire pump engines include:

- Combustion controls
- Selective Catalytic Reduction
- NO_X Adsorbers

<u>Combustion Controls</u>
Combustion control is implemented in the design of the internal combustion engine. Typical design features include an electronic fuel/air ratio and timing controllers, pre-chamber ignition, intercoolers, and lean-bum fuel mix. Currently available new engines include these features as standard equipment.

<u>Selective Catalytic Reduction</u>
SCR is a post-combustion NO_X reduction technology and uses NH_3 to react with NO_X in the gas stream in the presence of a catalyst. NH_3 and NO_X react to form nitrogen and water. The NO_X reduction reaction is effective only within a given temperature range. The optimum temperature range depends on the type of catalyst used and the flue gas composition. Optimum temperatures vary from 480°F to 800°F.[10] Typical catalyst material is titanium dioxide, tungsten trioxide, or vanadium pentoxide.

<u>NO_X Adsorbers</u>

[10] EPA's Air Pollution Control Technology Fact Sheet for SCR, EPA-452/F-03-032.

Similar to automobile catalytic converters, this method employs noble metal catalysts to oxidize nitrogen oxides to molecular nitrogen. The catalyst requires that exhaust have more than 0.5% O_2. This technique uses a fuel rich mixture that, combined with back pressure from exhaust flow through the catalyst, increases the brake specific fuel consumption of the engine.

5.11.1.2 Technical Feasibility Analysis (Step 2)
The feasible control technology for the diesel-fired emergency engines are combustion controls, SCR, and NO_X Adsorbers.

5.11.1.3 Ranking of Remaining Controls (Step 3)

SCR and NO_X Adsorbers can both achieve approximately 90% control and combustion controls can achieve approximately 80% control (Reference: Alpha Gamma Technologies, Inc., 2005).

5.11.1.4 Evaluation of Most Effective Controls (Step 4)

Because of the limited hours of operation and small emissions the cost impacts associated with add-on controls (SCR or NO_X Adsorbers) are prohibitive. The cost per ton removed are presented in Table 5-6 below.

Table 5-6 Cost of Control for NO_X Adsorbers and SCR[1]

Control Technology	Emergency Diesel Generator ($/ton)	Diesel Fire Pump ($/ton)
SCR	242,493	396,886
NO_X Adsorber	969,121	348,278

[1]Reference: Memorandum, Cost per Ton for NSPS for Stationary CI ICE, Alpha Gamma Technologies, Inc., June 9, 2005.

5.11.1.5 Selection of BACT (Step 5)

NTE proposes combustion controls and limited annual operating hours as BACT for the emergency engines, with NO_X limits of 4.7 g/bhp-hr for the emergency diesel generator and 2.7 g/bhp-hr for the diesel fire pump. These emission factors are set forth in Appendix B, Tables B-7 and B-8.

The DAQ however, notes that for all intents and purposes these proposed limits are equivalent to the emission standards required under NSPS IIII, which are obtained through proper operation and maintenance of a EPA certified engine. To maintain consistency and take advantage of any monitoring recordkeeping and reporting requirements under NSPS, the recommended BACT will be the following for NOx and VOC (i.e., NOx + NMHC):

4.8 g/bhp-hr for ES-4
3.0 g/bhp-hr for ES-5

5.11.2 Emergency Diesel Engine CO and VOC BACT

5.11.2.1 Identification of CO and VOC Control Technologies (Step 1)

The following control options are evaluated in the BACT analysis.

- Combustion controls;
- Oxidation Catalysts; and
- Catalyzed Diesel Particulate Filters (CDPF).

Combustion Controls
Combustion controls, which include 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. Good combustion system design, which includes continuous mixing of air and fuel in the proper proportions, extended residence time, and consistent high temperatures in the combustion chamber is a standard feature of modern engines. As a result, CO and VOC emissions from modern engines are inherently low.

Oxidation Catalysts
Similar to automobile catalytic converters, this method employs noble metal catalysts to oxidize nitrogen oxides to molecular nitrogen. It operates in regimes with less than 0.5% O_2 in the exhaust, which corresponds to fuel-rich operation. The method is not feasible with lean-burn internal combustion engines.

Catalyzed Diesel Particulate Filters (CDPF)
CDPFs are designed to remove PM from the diesel exhaust stream using a wall flow material in which the exhaust stream must pass through a ceramic wall. However, CDPFs also reduce emissions of CO and VOCs, and one manufacturer has demonstrated CO control of 90%.

5.11.2.2 Technical Feasibility Analysis (Step2)
Technical feasibility of the potential control options is evaluated below.

- **Combustion Controls.** Combustion controls, which include combustion system design and proper operation and maintenance practices, have been applied successfully to diesel engines and are considered technically feasible for the emergency diesel engines.
- **Oxidation Catalysts.** Oxidation catalysts operate in regimes with less than 0.5% O_2 in the exhaust, which corresponds to fuel-rich operation. The method is not feasible with lean-burn internal combustion engines.
- **CDPF.** CDPF has been identified as a feasible technology and has been evaluated further in EPA studies.

5.11.2.3 Ranking of Remaining Controls (Step 3)
The only feasible control technologies for the diesel fired emergency engines are combustion controls, which are inherent in the engine operation, and CDPF. Thus, ranking of control technologies is not necessary.

5.11.2.4 Evaluation of Most Effective Controls (Step 4)
Because of the low emissions, the cost impacts of add-on control are excessive as shown in Table 5-7 below;

Table 5-7 Cost of Control for CDPF[1]

Control	Emergency Diesel Generator CO ($/ton)	Emergency Diesel Generator VOC ($/ton)	Diesel Fire Pump CO ($/ton)	Diesel Fire Pump VOC ($/ton)
CDPF	19,674	157,174	47,336	114,682

[1]Reference: EPA Final Report, "Alternative Control Techniques Document: Stationary Diesel Engines, March 5, 2010.

5.11.2.5 Selection of BACT (Step 5)
NTE proposes combustion controls and limited annual operating hours as BACT for the emergency engines, and the following emission limits;

- Emergency Diesel Generator/CO-0.79 g/hp-hr and VOC-0.09 g/hp-hr
- Diesel Fire Pump/CO-0.4 g/hp-hr and VOC-0.1 g/hp-hr

These emission factors are set forth in Appendix B, Tables B-7 and B-8.

The DAQ however, notes that for all intents and purposes these proposed limits are equivalent to the emission standards required under NSPS IIII which are obtained through proper operation and maintenance of a EPA certified engine. To maintain consistency and take advantage of any monitoring recordkeeping and reporting requirements under NSPS, the recommended BACT will be the following for the requested engine sizes and year of construction:
for VOC and NOx (i.e., NMHC + NOx):

- 4.8 g/bhp-hr for ES-4
- 3.0 g/bhp-hr for ES-5

For CO:

- 2.6 g/bhp-hr for ES-4
- Good combustion practices for ES-5. NSPS IIII has no emission limitations for CO for this type, size and year of engine.

5.11.3 Emergency Diesel Engine PM10/PM2.5 BACT

5.11.3.1 Identification of PM10/PM2.5 Control Technologies (Step 1)
A small amount of PM results from the combustion of diesel fuel in the emergency engines. EPA identifies two types of smoke that may be emitted from diesel engines during stable operations (i.e., blue smoke and black smoke). Per EPA's AP-42 Section 3.3 (Gasoline and Diesel Industrial Engines), blue smoke is emitted when lubricating oil leaks, often past worn piston rings, into the combustion chamber and is partially burned. The primary constituent of black smoke is agglomerated carbon particles (soot) formed in regions of the combustion zone where mixtures are O_2 deficient.

The following control options are evaluated in the BACT analysis:

- Combustion Controls;
- Proper Maintenance;
- Catalyzed Diesel Particulate Filters (CDPF); and
- Flow Through Filters.

Combustion Controls
Carbon soot is formed in regions of combustion mixture that are O_2 deficient. Combustion controls, which include 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 carbon soot formation. Good combustion system design, which includes continuous mixing of air and fuel in the proper proportions, extended residence time, and consistent high temperatures in the combustion chamber, is a standard feature of modern engines.

Proper Maintenance
Blue smoke is emitted when lubricating oil leaks, often past worn piston rings, into the combustion chamber and is partially burned. Per EPA's AP-42 Section 3.3 (Gasoline and Diesel Industrial Engines), proper maintenance is the most effective method of preventing blue smoke emissions from all types of IC engines.

Catalyzed Diesel Particulate Filter (CDPF)
CDPFs are designed to remove PM from the diesel exhaust stream using a wall flow material in which the exhaust stream must pass through a ceramic wall. In addition to PM, CDPFs also reduce emissions of CO and VOCs. The CDPF is reported to reduce PM emissions by 85%.

Flow Through Filter (FTF)
A FTF contains a network of flow through channels consisting of a catalyzed wire or corrugated metal foil. The exhaust gas flows through channels in the filter medium collecting PM on the surface of the metal fibers. PM reductions vary between 30% and 70%.

5.11.3.2 Technical Feasibility Analysis (Step 2)
Technical feasibility of the potential control options is evaluated below.

- Combustion Controls. Combustion controls, which include combustion system design and proper operation and maintenance practices, have been applied successfully to diesel engines and are considered technically feasible for the emergency diesel engines.
- Proper Maintenance. Proper maintenance is effective in minimizing particulate emissions and is considered technically feasible.
- CDPF is considered technically feasible for PM control.
- FTF is considered technically feasible for PM control.

5.11.3.3 Ranking of Remaining Controls (Step 3)
The feasible control technologies for the diesel-fired emergency engines are the four referenced control technologies. The CDPF can achieve approximately 85% control and the FTF can achieve up to 70% control.

5.11.3.4 Evaluation of Most Effective Controls (Step 4)
Because of the low emissions, the cost impacts of add-on controls are excessive as shown in Table 5-8 below.

Table 5-8 Cost of Control for CDPF and Flow Through Filters[1]

Control Technology	**Emergency Diesel Generator ($/ton)**	**Diesel Fire Pump ($/ton)**
CDPF	59,506	70,180
Flow Through Filters	30,140	44,175

[1]Reference: EPA Final Report, “Alternative Control Techniques Document: Stationary Diesel Engines, March 5, 2010.

5.11.3.5 Selection of BACT (Step 5)
NTE proposes combustion controls and limited annual operating hours as BACT for the emergency engines. These limits will be set to the emission limits required NSPS subpart IIII which are obtained through proper operation and maintenance of an EPA certified engine. For the requested engine sizes and year of construction the applicable limit would be:

- 0.15 g/bhp-hr for ES-4
- 0.15 g/bhp-hr for ES-5

5.11.4 Emergency Diesel Engine GHG BACT
GHG emissions from the emergency diesel engines result from oxidation of fuel carbon. This evaluation does not identify and discuss each of the five individual steps of the "top-down" BACT process, since there are no post-combustion control technologies available for GHG emissions from small emergency diesel engines.

The DAQ recommends BACT to be good combustion practices and the proper operation and maintenance of an EPA certified engine consistent with NSPS Subpart IIII.

Based on the proposed annual fuel consumption limits for these units, total CO_{2e} emissions would be limited to 486 TPY for the emergency diesel generator and 86 TPY for the diesel fire pump engine.

5.12 BACT for Auxiliary Boiler and Fuel Gas Fuel Gas Heater

The project will include an 85 MMBtu/hr auxiliary boiler (ES-2) and a 9 MMBtu/hr fuel gas fuel gas heater (ES-3), both exclusively fired with natural gas. The auxiliary boiler will operate as needed (up to 4,560 hours per year at maximum rated capacity) to keep the HRSG warm during periods of turbine shutdown and provide sealing steam to the steam turbine during warm and hot starts. The fuel gas heater will operate as necessary (up to a maximum of 8,760 hours per year) to condition the natural gas prior to combustion to prevent condensation. Combustion of natural gas in both units will yield emissions of NO_X, $PM/PM_{10}/PM_{2.5}$, CO, VOC, H_2SO_4 and GHG, each subject to BACT. There are no applicable numerical emission standards under NSPS or MACT for either unit for these pollutants. The only SIP emission standards that exist are for PM (0.2 lb/MMBtu under 15A NAC 02D .0503) and indirectly for H_2SO_4 via SO2 (2.3 lb/MMBtu under 15A NCAC 02D .0516).

To support the BACT analyses, a search of the RBLC and other permits not included in the RBLC was performed for auxiliary boilers and fuel gas heaters at large combined-cycle power projects in the past five years. These determinations are summarized in Appendix D, Tables D-6 and D-7.

The following table is reproduced from the application to highlight the relatively low emissions of pollutants from these sources.

Table 3-9 Potential Hourly and Annual Emissions from Natural Gas-Fired Boiler and Fuel Gas Heater

	Auxiliary Boiler[1]		Fuel Gas Heater[2]	
Pollutant	**lb/hr**	**TPY**	**lb/hr**	**TPY**
NO_X	0.85	1.94	0.11	0.48
CO	3.15	7.18	0.33	1.45
VOC	0.43	0.98	0.03	0.13
$PM_{10}/PM_{2.5}$	0.60	1.37	0.06	0.26
SO_2	0.12	0.27	0.01	0.04
H_2SO_4	0.02	0.05	0.002	0.009
Lead	4.2E-05	9.6E-05	4.4E-06	1.9E-05
NH_3	0.26	0.59	0.03	0.13
GHG	10,014	22,830	1,061	4,646

	Auxiliary Boiler[1]		Fuel Gas Heater[2]	
Pollutant	**lb/hr**	**TPY**	**lb/hr**	**TPY**
Total HAPs	0.16	0.36	0.017	0.07
Highest (Hexane)	0.15	0.34	0.016	0.07

[1]Based on 4,560 hrs/yr operation.
[2]Based on 8,760 hrs/yr operation.

5.12.1 Auxiliary Boiler/Fuel Gas Heater NOX BACT

5.12.1.1 Identification of NOX Control Technologies (Step 1)

Potentially available control options for reducing NO_X emissions from natural gas-fired auxiliary boilers and fuel gas heaters include:

- Low-NO_X (LN) burner, typically with flue gas recirculation (FGR)
- Ultra-Low-NO_X (ULN) burner
- Selective Catalytic Reduction (SCR)

Combustion controls such as LN and ULN burners and FGR are designed to control thermal and/or fuel NO_X formation by controlling the air-to-fuel ratio and combustion temperature. SCR is an add-on control used to remove NO_X from the exhaust gas stream once it has been formed.

5.12.1.2 Technical Feasibility Analysis (Step 2)

Each of the identified controls are considered technically feasible.

5.12.1.3 Ranking of Controls (Step 3)

Based on a review of RBLC and other permit determinations, as summarized in Appendix D, the ranking of technologies is as follows:

1. SCR: 5.0 ppmvd @ 3% O_2 (~0.006 lb/MMBtu) is considered demonstrated for gas-fired boilers. SCR can be used as supplemental control with a LN burner, but has not been demonstrated with an ULN burner.
2. ULN burner: 9.0 ppmvd @ 3% O_2 (~0.01l lb/MMBtu) is considered demonstrated for gas-fired boilers.

3. LN burner, typically with FGR: 30 ppmvd @ 3% O_2 (~0.036 lb/MMBtu) is considered demonstrated for gas-fired boilers.

5.12.1.4 Evaluation of Most Effective Controls (Step 4)
Since SCR is technically feasible, an economic analysis of the cost effectiveness for emission control was conducted. This economic analysis is summarized in Appendix F, Tables F-1 and Table F-2 for the auxiliary boiler and fuel gas heater, respectively. The cost impact analyses indicate that the overall cost effectiveness ratios of an SCR are excessive, at $36,404 per ton for the auxiliary boiler and $31,495 per ton for the fuel gas heater. These values are not considered to be reasonable. There are no energy or environmental issues with ULN burners that would indicate selection of SCR as BACT, given the unfavorable SCR economics.

5.12.1.5 Selection of BACT
The lowest NO_X limit identified for any auxiliary boiler or fuel gas heater at a combined-cycle power plant summarized in Appendix D, Tables D-6 and D-7, is consistent with the standard guarantee for ULN burners, which is 9 ppmvd at 3% O_2, corresponding to 0.011 lb/MMBtu. NTE proposes to meet this most stringent limit with ULN burners to satisfy BACT requirements.

5.12.2 Auxiliary Boiler/Fuel Gas Heater CO and VOC BACT

5.12.2.1 Identification of CO and VOC Control Technologies (Step 1)
Potentially available control options for reducing CO and VOC emissions from natural gas-fired auxiliary boilers and fuel gas heaters include:

- Combustion Controls
- Oxidation Catalysts

Providing adequate fuel residence time and high temperature in the combustion device to ensure complete combustion can minimize CO and VOC emissions. However, these combustion techniques can sometimes increase NO_X emissions. Conversely, a low NO_X emission rate achieved by flame temperature control can result in higher CO and VOC emissions. Therefore, a compromise must be reached whereby the flame temperature reduction is set to achieve the lowest NO_X emission rate possible while maintaining CO and VOC emission rates at acceptable levels.

Oxidation catalysts are a proven post-combustion control technology widely in use on large CTs and other large combustion units to abate CO emissions. An oxidation catalyst oxidizes the CO in the exhaust gases to form CO_2 and is typically designed to achieve 80% CO control. Less VOC control will be achieved due to the relatively low concentrations of VOC relative to CO in the combustion exhaust gas and manufacturers will typically not guarantee VOC control efficiencies in these applications. Therefore, oxidation catalysts are not typically specified for VOC control on combustion sources.

5.12.2.2 Technical Feasibility Analysis (Step 2)
Each of the identified controls is considered technically feasible.

5.12.2.3 Ranking of Controls (Step 3)
Based on a review of RBLC and other permit determinations, as summarized in Appendix D, the ranking of technologies is as follows:

CO
1.Oxidation catalyst: 0.0035 lb/MMBtu, based on a limit contained in the draft permit for the Footprint Power Salem Harbor plant. However, this plant has not been constructed and the limit is not considered demonstrated in practice. Moreover, as referenced in the KMEC application, Footprint Power's proposal to include an oxidation catalyst was made as a concession in a contested permitting proceeding as well as for PSD review avoidance for CO.

2.Combustion controls: 50 ppmvd @ 3% O_2 (~0.037lb/MMBtu) is the most stringent limit contained in a permit for an auxiliary boiler or fuel gas heater equipped with an ULN burner.

VOC:
3.Combustion controls: 0.0015 to 0.006 lb/MMBtu is generally the range of VOC limits contained in permits for auxiliary boilers and fuel gas heaters, equipped with ULN burners at large combined-cycle projects.

5.12.2.4 Evaluation of Most Effective Controls (Step 4)

Since an oxidation catalyst is technically feasible for CO emissions from natural gas-fired auxiliary boilers and fuel gas heaters, an economic analysis of the cost effectiveness of CO control was conducted. This economic analysis is summarized in Appendix F, Table F-3 and Table F-4 for the auxiliary boiler and fuel gas heater, respectively. The cost impact analyses indicate that the overall cost effectiveness ratios indicate that the overall cost effectiveness ratios of oxidation catalysts in these cases are excessive, at $29,099 per ton for the auxiliary boiler and $92,571 per ton for the fuel gas heater. These values are not considered to be reasonable.

5.12.2.5 Selection of BACT (Step 5)

The lowest CO limit identified for any auxiliary boiler or fuel gas heater at a combined-cycle power plant without an oxidation catalyst, as summarized in Appendix D, Tables D-6 and D-7, is 50 ppmvd at 3% O_2, corresponding to 0.037 lb/MMBtu. Based on excessive and unreasonable cost impact, use of oxidation catalysts was ruled out as BACT for both the auxiliary boiler and fuel gas heater.

For VOC, the most stringent permit limits for auxiliary boilers and fuel gas heaters equipped with ULN are generally in the range of 0.0015 lb/MMBtu to 0.006 lb/MMBtu. Moreover, the more recent VOC permit limits are in 0.0054 to 0.021 lb/MMBtu range (Mattawoman Energy). As discussed earlier, the EPA recognizes that there are minor differences in the BACT emission limits for emission units with the same control technology due to differences in the specific emission unit make and model. Thus, for CO, NTE proposes to meet 0.037 lb/MMBtu for the auxiliary boiler and 0.037 lb/MMBtu for the fuel gas heater. For VOC, NTE proposes 0.005 lb/MMBtu VOC as BACT for the auxiliary boiler and 0.003 lb/MMBtu for the fuel gas heater.

5.12.3 Auxiliary Boiler and Fuel Gas Heater PM10/PM2.5 BACT

For $PM/PM_{10}/PM_{2.5}$, this evaluation does not identify and discuss each of the five individual steps of the "top-down" BACT process, since there are no post-combustion control technologies available for $PM_{10}/PM_{2.5}$ emissions from small natural gas-fired boilers and fuel gas heaters.

There are no applicable NSPS $PM_{10}/PM_{2.5}$ standards applicable to natural gas-fired equipment of the size range specified for the proposed auxiliary boiler or fuel gas heater. 15A NCAC 02D .0503(c) would limit total PM emissions from the auxiliary boiler and fuel gas heater to 0.2 lb/MMBtu.

NTE proposes exclusive use of natural gas with a sulfur content of 0.75 grains/100 SCF in the auxiliary boiler and fuel gas heater to minimize emissions of $PM/PM_{10}/PM_{2.5}$, which represents the most stringent control available for this natural gas-fired equipment. The proposed $PM/PM_{10}/PM_{2.5}$ emission limit based on AP-42 emission factors and the proposed fuel sulfur content (for both the auxiliary boiler and fuel gas heater) is 0.007 lb/MMBtu. NTE proposes to meet the limit based on fuel sulfur monitoring/fuel supplier certifications.

Sulfur content in natural gas	0.75 grains/100 SCF (enforceable through fuel supplier certifications/monitoring records)
$PM/PM_{10}/PM_{2.5}$ (total filterables + condensables)	0.007 lb/MMBtu (estimated based on fuel sulfur content limit and AP-42 emission factors). If necessary, initial stack testing would be performed using EPA Reference Methods 201 or 201A for filterable PM and Method 202 (revised 1211 0/11 for condensable PM).

Limiting the amount of sulfur in the fuel is a common practice for natural gas-fired combustion equipment. All new gas-fired boilers, properly operated, are expected to have intrinsically low $PM/PM_{10}/PM_{2.5}$ emissions. A limit of 0.007 lb/MMBtu is within the range of recent PSD BACT levels and is justified as PSD BACT based on the proposed sulfur content limit of 0.75 grains/100 SCF.

5.12.4 Auxiliary Boiler and Fuel Gas Heater GHG BACT

GHG emissions from the auxiliary boiler and fuel gas heater result from oxidation of fuel carbon. This evaluation does not identify and discuss each of the five individual steps of the "top-down" BACT process, since there are no post-combustion control technologies available for GHG emissions from small natural gas-fired boilers and fuel gas heaters.

With respect to GHG, most of the auxiliary boilers and fuel gas heaters listed in Appendix D with GHG limits for PSD BACT are expressed as a mass emission value, which is a project specific number reflecting the particular size and gas throughput limits of the specific project unit. The proposed project's proposed GHG limit for the auxiliary boiler and fuel gas heater is based on the USEPA AP-42 emission factor (117.64 lb CO_2/MMBtu*)* for natural gas combustion. One unit listed in the RBLC (for the St. Joseph Energy Center in New Carlisle, IN) also has an 80 percent efficiency specified in addition to an annual mass limit. This is the only auxiliary boiler approved with this type of limit. The proposed project will install an auxiliary boiler with a nominal efficiency of at least 80 percent. NTE proposes a GHG PSD BACT limit expressed in the units of lb/MMBtu *(*117.64 lb CO_2/MMBtu*).* Based on the proposed annual fuel consumption limits for these units, total CO_{2e} emissions would be limited to 22,830 TPY for the auxiliary boiler and 4,645 TPY for the fuel gas heater. The CO_{2e} emissions from these units will be monitored by monitoring fuel use and using fuel-specific emission factors (e.g., AP-42 Table 1.4-2) to calculate total CO_{2e} on a 12-month rolling basis.

5.13 BACT for Cooling Tower PM10/PM2.5

The proposed project will include a mechanical draft, counter flow, multi-cell cooling tower to provide steam condenser cooling needs for the power plant.

Emissions from the cooling tower consist only of PM/PM_{10}/$PM_{2.5}$. These emissions originate from the dissolved and suspended solids contained in droplets of cooling water, called "drift," that escape in the air stream exiting the cooling tower. Because drift droplets contain the same chemical impurities as the water circulating through the tower, these impurities can be converted to airborne emissions. The magnitude of drift loss is influenced by the number and size of droplets produced within the cooling tower, which in turn are determined by the fill design, the air and water patterns, and the efficiency of the drift eliminator. Drift eliminators are incorporated into the tower design to remove as many droplets as practical from the air stream before the air exits the tower. PM/PM_{10}/$PM_{2.5}$ emissions from cooling towers are usually estimated by using the tower's design drift rate, the Total Dissolved Solids (TDS) concentration of the tower's incoming cooling water, and the number of cycles of concentration in the tower. A high efficiency drift eliminator with a drift rate of 0.0005 percent is proposed for the project.

5.13.1 Identification of Control Technologies (Step 1)

Potentially available control options for reducing PM/PM_{10}/$PM_{2.5}$ emissions from mechanical draft wet cooling towers are as follows:

- Air-Cooled Condensers (ACCs): This eliminates the use of circulating water for cooling and thus eliminates drift for large towers used for steam turbine condenser cooling
- High efficiency cooling tower drift eliminators.
- Reduction in the dissolved solids concentration in circulating water.

5.13.2 Technical Feasibility Analysis (Step 2)

Each of the identified controls is considered technically feasible. However, ACCs are typically only considered for projects where available water supply sources have insufficient capacity to meet project needs. They are typically not evaluated where sufficient water supply capacity is available due to increased size, costs, and energy impacts relative to wet cooling towers. Since the proposed project will be using local municipal water supply for its water needs, ACCs were not considered feasible for the project or in this BACT analysis.

NTE is proposing use of high-efficiency drift eliminators. The only alternative would be to reduce the solids content of the water, either by water treatment or by reducing the cycles of concentration. NTE will be using the local municipal water supply for the project, which typically has a TDS content less than 100 mg/l according to the application. The Permittee estimated emissions based on a TDS content of 2,000 mg/l. The maximum cycles of concentration will be maintained below 8.

5.13.3 Ranking of Controls (Step 3)

Based on a review of RBLC and other permit determinations, as summarized in Appendix D, Table D-8, the ranking of technologies is as follows:

1. High efficiency cooling tower drift eliminators: Generally recognized as capable of achieving a drift rate of 0.0005 of circulating water flow for large cooling tower used for power plant steam turbine condenser cooling.
2. Reduce the TDS in circulating water: Mechanical draft cooling towers are operated with circulating water TDS as low as 1000 milligrams/liter (mg/l).

5.13.4 Evaluation of Most Effective Controls (Step 4)

Based upon a review of PM/PM_{10}/$PM_{2.5}$ emissions and controls identified from a search of EPA's RBLC and other permit determinations, drift eliminators and minimizing circulating water TDS are considered the only technically feasible options.

5.13.5 Selection of BACT (Step 5)

Appendix D includes a summary of PSD BACT determinations in the last six years for mechanical draft cooling towers at new large (> 100 MW) combustion turbine combined cycle projects. Review of the most recent BACT determinations in Appendix D, Table D-8 indicates that the wet cooling towers are commonly specified for 0.0005 drift, in fact, nine of the last 10 permitted were specified for 0.0005% drift. Therefore, NTE will specify high-efficiency drift eliminators, designed for 0.0005% drift loss for the wet cooling towers at the proposed facility.

With respect to the circulating water TDS concentration, for projects where this value is identified, these values range from 1000 to 6200 mg/l. A collateral environmental impact of increasing the blowdown to decrease TDS is increasing water consumption. NTE is proposing 2000 mg/l as a conservative reasonable maximum TDS value to balance drift emissions and water conservation.

The NC DAQ concurs with the proposed PM10/PM2.5 BACT limitations considering the goals of BACT which takes "into account energy, environment, and economic impacts and other costs, determines is achievable... for control of such a pollutant." The permit will require the use of the mist eliminators as BACT and contain associated monitoring in the form of manufacturer recommended inspections and maintenance. Associated recordkeeping and reporting will also be required to ensure compliance.

5.14 BACT for GHG Emissions from Fugitive Natural Gas

The proposed project will include natural gas piping to transport fuel to all project combustion equipment. Natural gas piping components, such as connections, valves, compressor seals, etc. are potential small sources of fugitive CH_4 and CO_2. In addition, intentional periodic purging of natural gas related to piping maintenance and turbine startups/shutdowns, as required for safety reasons, will also occur. The project will implement best management practices, including routine inspections/monitoring to minimize fugitive leaks from the piping components.

5.14.1 Identification of Available Control Technologies (Step 1)

Based on a review of recent BACT evaluations and determinations for combined-cycle power plants, the following technologies were identified as potential control options for piping fugitive emissions:

- Implementation of a leak detection and repair (LDAR) program using a handheld analyzer;
- Implementation of alternative monitoring using a remote sensing technology such as infrared cameras; and
- Implementation of routine audio/visual/olfactory (AVO) walk-through inspections.
- For purging of natural gas piping associated with piping maintenance and startups/shutdowns, which is necessary for safety reasons, the only available control option is to minimize startups and shutdowns to the extent that is practical within the context of the project's operational scenarios and power contract obligations.

5.14.2 Elimination of Technically Infeasible Options (Step 2)

The use of instrument LDAR and remote sensing technologies are technically feasible. Since pipeline natural gas is odorized with a small amount of mercaptan, AVO leak detection methods for natural gas piping components is also technically feasible.

5.14.3 Ranking of Remaining Control Technologies (Step 3)

The use of a LDAR program with a portable gas analyzer meeting the requirements of 40 CFR 60, Appendix A, Method 21, can be effective for identifying leaking methane. Quarterly instrument monitoring with a leak definition of 10,000 part per million by volume (ppmv) (TCEQ 28M LDAR Program) is generally assigned a control efficiency of 75 for valves, relief valves, sampling connections, and compressors and 30 for flanges. Quarterly instrument monitoring with a leak detection of 500 ppmv (TCEQ 28VHP LDAR Program) is generally assigned a control efficiency of 97% for valves, relief valves, and sampling connections, 85% for compressors, and 30% for flanges.[11] The U.S. EPA has allowed the use of an optical gas imaging instrument as an alternative work practice for a Method 21 portable analyzer for monitoring equipment for leaks in 40 CFR 60.18(g). For components containing inorganic or odorous compounds, periodic AVO walk-through inspections provide predicted control efficiencies of 97% control for valves, flanges, relief valves, and sampling connections, and 95% for compressors.

5.14.4 Evaluation of Most Effective Controls (Step 4)

The frequency of inspection and the low odor threshold of mercaptans in natural gas make AVO inspections an effective means of detecting leaking components in natural gas service. As discussed above, the predicted emission control efficiency is comparable to the LDAR programs using Method 21 portable analyzers.

5.14.5 Selection of BACT (Step 5)

Since the uncontrolled CO_{2e} emissions from the natural gas piping represent less than 0.02 percent of the total Project CO_{2e} emissions, any emission control techniques applied to the piping fugitives will provide minimal CO_{2e} emission reductions. Based on this top-down analysis, NTE proposes to implement daily AVO inspection walk-throughs as BACT for piping components in natural gas service. For purging of natural gas piping for piping maintenance and for startups/shutdowns, the standard industry work practice is the only practical means of minimizing emissions and is therefore considered to be BACT for the proposed project.

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[11] Control Efficiencies for TCEQ Leak Detection and Repair Programs, available at www.tceg.state.tx.us/assets/public/permitting/ air/Guidance/NewSourceReview/control_eff.pdf

5.15 BACT for SF6 Insulated Electrical Equipment Fugitive GHGs

The proposed project will use electrical circuit breakers insulated with sulfur hexafluoride (SF_6), a regulated greenhouse gas (GHG). Annual potential fugitive emissions of SF_6 from the circuit breakers and switchers, based on a maximum leakage rate of 0.5 percent per year, equate to about 0.004 percent of total project GHG emissions. The proposed circuit breakers will be state-of-the art sealed units, equipped with low pressure alarms for leak detection and a low pressure lockout to minimize fugitive losses of SF_6. This BACT analysis provides further justification of the circuit breaker design and controls.

5.15.1 Identification of Available SF6 Control Technologies (Step 1)

One technology is the use of state-of-the-art SF_6 technology with leak detection to limit fugitive emissions. In comparison to older SF_6 circuit breakers, modern breakers are designed as a totally enclosed-pressure system with far lower potential for SF_6 emissions. In addition, the effectiveness of leak-tight closed systems can be enhanced by equipping them with a density alarm that provides a warning when 10 percent of the SF_6 (by weight) has escaped. The use of an alarm identifies potential leak problems before the bulk of the SF_6 has escaped, so that it can be addressed pro-actively in order to prevent further release of the gas.

One alternative considered in this analysis is to substitute another, non-GHG substance for SF_6 as the dielectric material in the breakers. Potential alternatives to SF_6 are reviewed in the National Institute of Standards and Technology (NIST) Technical Note 1425, Gases for Electrical Insulation and Arc Interruption: Possible Present and Future Alternatives to Pure SF_6.[12] These alternatives include use of dielectric oil or compressed air ("air blast") circuit breakers, which historically were used in high-voltage applications prior to the development of SF_6 breakers, and the use of other non-GHG gases or gas mixtures in place of SF_6.

5.15.2 Elimination of Technically Infeasible Options (Step 2)

According to the report NIST Technical Note 1425, SF_6 is a superior dielectric gas for nearly all high voltage applications. It is easy to use, exhibits exceptional insulation and arc-interruption properties, and has proven its performance by many years of use and investigation. It is clearly superior in performance to the air and oil insulated equipment used prior to the development of SF_6-insulated equipment. "The use of SF_6 insulation has distinct advantages over oil insulation, including none of the fire safety problems or environmental problems related to oil, high reliability, flexible layout, little maintenance, long service life, lower noise, better handling, and lighter equipment." In addition, "…for gas insulated circuit breakers there are still significant questions concerning the performance of gases other than pure SF_6." The report concluded that although " ... various gas mixtures show considerable promise for use in new equipment, particularly if the equipment is designed specifically for use with a gas mixture ... it is clear that a significant amount of research must be performed for any new gas or gas mixture to be used in electrical equipment." Therefore, there are currently no technically feasible options besides use of SF_6.

5.15.3 Ranking of Remaining Control Technologies (Step 3)

The use of state-of-the-art SF_6 technology with leak detection to limit fugitive emissions is the highest ranked control technology that is technically feasible for this application.

5.15.4 Evaluation of Most Effective Controls (Step 4)

Energy, environmental, or economic impacts were not addressed in this analysis because the use of alternative, non-greenhouse-gas substance for SF_6 as the dielectric material in the breakers is not considered technically feasible.

5.15.5 Selection of BACT and Determination of SF6 Limits (Step 5)

Based on this top-down analysis, NTE concludes that using state-of-the-art enclosed-pressure SF_6 circuit breakers with leak detection would be the BACT control technology option. The circuit breakers will be designed to meet the latest of the American National Standards Institute (ANSI) C37.013 standard for high voltage circuit breakers.[13] The proposed circuit breaker at the generator output will have a low pressure alarm and a low pressure lockout. This alarm will function as an early leak detector that will bring potential fugitive SF_6 emissions problems to light before a substantial portion of the SF_6 escapes. The lockout prevents any operation of the breaker due to lack of "quenching and cooling" SF_6 gas. This BACT determination is consistent with the recent determinations for fugitive SF_6 emissions from circuit breakers.[14]

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[12]Christophorous, L.G., J.K. Olthoff, and D.S. Green, "Gases for Electrical Insulation and Arc Interruption: Possible Present and Future Alternatives to Pure SF6, NIST Technical Note 1425, Nov. 1997. www.epa.gov/electricpower-sf6/documents/new_ report_final.pdf

[13] ANSI Standard C37.013, Standard for AC High-Voltage Generator Circuit Breakers on a Symmetrical Current.

[14] Indeck Wharton Energy Center, EPA Region 6, Statement of Basis, Draft Greenhouse Gas Prevention of Significant Deterioration Preconstruction Permit, April 2014.

NTE will monitor and report emissions annually in accordance with the requirements of the Mandatory Greenhouse Gas Reporting rules for Electrical Transmission and Distribution Equipment Use.[15] Annual SF_6 emissions will be calculated according to the mass balance approach in Equation DD-l of Subpart DD to Part 98, which requires tracking of the amount of SF_6 dielectric fluid added to the circuit breakers for each month of facility operation.

[15] 40 C.F.R. Part 98, Subpart DD.

6. PSD Air Dispersion Modeling Analysis

Introduction
The PSD modeling analysis described in this section was conducted in accordance with current PSD directives and modeling guidance. References are made to the Draft October 1990 EPA New Source Review Workshop Manual, Prevention of Significant Deterioration and Nonattainment Area Permitting which will herein be referred to as the NSR Workshop Manual.

A summary of the modeling results is presented in the last topic, PSD Air Quality Modeling Results Summary. A detailed description of the modeling and modeling methodology is described below.

Project Description / Significant Emission Rate (SER) Analysis
The NTE Carolinas II, LLC proposed natural gas-fired electric generating facility includes a combined cycle combustion turbine (CT), heat recovery steam generator, steam turbine, an auxiliary boiler, a fuel gas heater, a mechanical draft evaporative cooling tower, an emergency diesel generator, and a diesel powered fire water pump for their Reidsville Energy Center (hereafter referred to as NTE-Reidsville) located in Reidsville, NC. Two potential equipment configurations were modeled: 1) Mitsubishi Hitachi Power Systems Americas, Inc. (MHPSA) and 2) Siemens Energy, Inc. (Siemens). Six pollutants (NOx, PM_{10}, $PM_{2.5}$, H_2SO_4, CO and VOC) were declared to exceed the PSD Significant Emissions Rate (SER) and thus require a PSD analysis. These emission rates are provided in Table 1 below:

Table 1 – Pollutant Netting Analysis

Pollutant	Annual Emission Rate (tons/yr)		Significant Emission Rate (tons/yr)	PSD Review Required?
	Mitsubishi	Siemens		
NO_x	126.35	128.10	40	Yes
PM_{10}	85.76	86.64	15	Yes
$PM_{2.5}$	84.03	84.91	10	Yes
H_2SO_4	30.35	12.98	7	Yes
SO_2	31.78	34.27	40	No
CO	289.69	107.54	100	Yes
Total HAPs	11.48	12.00	10/25	No
Pb	0.000147	0.000147	0.6	No
VOC	101.52	57.18	40	Yes

It should be noted that VOC's are not typically modeled as part of the PSD permitting process for areas that are NO_x limited for ozone formation. Given the fact that the emissions are not significant when compared to the historical evaluation threshold established by USEPA, VOC's were not required to be evaluated further for this project. Additionally, there would be no anticipated impacts of the NOx emissions from the proposed facility on ozone concentrations in the area. This area is in attainment for ozone, despite the nearby larger NOx emitting facilities identified in the Class II Area Full Impact Air Quality Modeling Analysis. Because of this, and previously conducted SIP modeling, NTE-Reidsville's lower NOx emissions are not anticipated to have an impact on the area's continued ozone attainment status. H_2SO_4 was evaluated under NCDAQ's Toxics procedures and are discussed later in this document.

Preliminary Impact Air Quality Modeling Analysis
An air quality preliminary impact analysis was conducted for the pollutants exceeding their corresponding SERs. The modeling results were then compared to applicable Significant Impact Levels (SILs) as defined in the NSR Workshop Manual to determine if a full impact air quality analysis would be required for that pollutant.

The NTE-Reidsville facility is located in Reidsville, NC, in Rockingham County. For modeling purposes, the area, including and surrounding the site, is classified rural, based on the land use type scheme established by Auer 1978. NTE-Reidsville evaluated the pollutant's significant emissions using AERMOD (Version 16216r). Five years (2010-2014) of surface and upper air meteorological data from the Greensboro National Weather Service (NWS) station were used. Full terrain elevations were included, as were normal regulatory defaults. Sufficient receptors were placed in ambient air beginning at the fenceline to establish maximum impacts. Project-specific emission rates for each equipment configuration was used and the maximum impacts were then compared to the respective SIL. A load analysis was initially conducted to determine under which operating conditions the maximum for each pollutant and averaging period were expected to occur.

Table 2 - Class II Significant Impact Results (μg/m^3)

Pollutant	Averaging Period	Turbine Option	Facility Maximum Impact	Class II Significant Impact Level	Significant Impact Distance (km)
NO_2	1-hour	Mitsubishi	**112**	**10**	7.6
		Siemens	**112**		7.6
	Annual	Mitsubishi	0.77	1	NA
		Siemens	0.85		NA
CO	1-hour	Mitsubishi	342.5	2,000	NA
		Siemens	97		NA
	8-hour	Mitsubishi	282.6	500	NA
		Siemens	75		NA
$PM_{2.5}$	24-hour	Mitsubishi	**3.5**	**1.2**	0.87
		Siemens	**3.5**		0.83
	Annual	Mitsubishi	**0.40**	**0.2**	0.29
		Siemens	**0.40**		0.29
PM_{10}	24-hour	Mitsubishi	4.29	5	NA
		Siemens	4.29		NA
	Annual	Mitsubishi	0.55	1	NA
		Siemens	0.54		NA

Class II Area Full Impact Air Quality Modeling Analysis
A Class II Area NAAQS and PSD Increment Analysis was performed for NO_2 for the 1-hour averaging period and for both 24-hour and annual averaging periods for $PM_{2.5}$ to include offsite emissions and background concentrations. NTE-Reidsville used AERMOD with the modeling methodology as described previously. Off-site source inventories for both increment and NAAQS modeling were obtained from NCDAQ and then refined using the 'Q/D=20'guideline. All sources that exceeded the value of 20 were included in the full impact analysis.

In accordance with recent USEPA draft $PM_{2.5}$ modeling guidance, NCDAQ instructed NTE-Reidsville to address both primary and secondarily formed $PM_{2.5}$. As detailed in Section 5.7 of the modeling report, it is not believed that secondary formation of $PM_{2.5}$ will contribute significantly to any violation of the NAAQS and no further evaluation of secondary formation was required.

Receptors where the SIL was exceeded in the previous analysis were modeled in the NAAQS analysis. NO_2 background concentrations were obtained from the Forsyth County monitor and $PM_{2.5}$ background concentrations were obtained from the Guilford County monitor. Design values from the monitors for the 2012-2014 period, that has complete data, were used as the background concentrations. The modeling results are shown in Table 3 and show that, although there were modeled exceedances of the NAAQS for NO_2, the NTE-Reidsville project did not contribute significantly to those exceedances since their contribution was less than the SIL. NCDAQ is in discussions with the other facility about the potential NAAQS violations attributable to their facility's emissions.

Table 3 – Class II Area NAAQS Modeling Results (µg/m^3)

Pollutant	Averaging Period	Max. Impact NTE & Other Sources + Background	NAAQS	% NAAQS	Max. Project Impact	SIL	Project Impact > SIL
NO_2 Mitsubishi	1-hour	1,600	188	851	4.6	10	No
NO_2 Siemens	1-hour	1,600	188	851	8.0	10	No
$PM_{2.5}$	24-hour	25.7	35	73	NA	NA	NA
$PM_{2.5}$	Annual	10.7	12	89	NA	NA	NA

Note: The modeled results for $PM_{2.5}$ were the same for both equipment configurations.

An increment value for the NO_2 1-hour averaging period has not been established by the USEPA; therefore no Class II increment analysis was conducted.

For the Class II increment analysis for $PM_{2.5}$, NTE-Reidsville used the same onsite sources and receptors as in the NAAQS analysis. This is the first PSD applicant in Rockingham County to trigger for PM2.5, since the USEPA October 20, 2011 major source baseline date. Therefore they are the only facility in this analysis. Under North Carolina's SIP the PM2.5 major source baseline date is January 6, 1975. For the 1975 trigger date, the assumption was made that $PM_{2.5}$ emissions are equal to all PM_{10} and TSP increment consuming sources. The results of the analysis are shown in Table 4 for both the USEPA October 20, 2011 and the NCDAQ January 6, 1975 $PM_{2.5}$ trigger date analyses. The Class II increment modeling results show that the project does not contribute significantly to any exceedances of the $PM_{2.5}$ Class II Area increment.

Table 4 – Class II PSD Increment Modeling Results (µg/m^3)

Pollutant	Averaging Period	Trigger Date	Maximum Source Impact	PSD Increment	% Increment
$PM_{2.5}$	24-hour	1975	8.7	9	97
		2011	3.49		39
	Annual	1975	1.0	4	25
		2011	0.40		10

Note: The modeled results for $PM_{2.5}$ were the same for both equipment configurations.

Non-Regulated Pollutant Impact Analysis (North Carolina Toxics)
NTE-Reidsville also modeled five air toxics using AERMOD with the same receptor array and meteorology as used in the NAAQS analysis. A list of the facility sources and emission rates used are attached to this document. All pollutants demonstrated compliance on a source-by-source basis with the NC's AAQS or Acceptable Ambient Level (AAL). The maximum concentrations are shown in Table 5.

Table 5 – Non-Regulated Pollutants Modeling Results (μg/m^3)

Pollutant	Averaging Period	Turbine Option	Maximum Facility Impact	AAL	% of AAL
H_2SO_4	1-hour	Both	10.2	100	10
	24-hour	Both	2.57	12	21
Ammonia	1-hour	Mitsubishi	5.97	2,700	0.2
		Siemens	6.39		0.2
Benzene	Annual	Both	0.018	0.12	15
Chromic Acid	24-hour	Both	0.00036	0.62	0.1
Formaldehyde	1-hour	Mitsubishi	0.397	150	0.3
		Siemens	0.450		0.3

Additional Impacts Analysis
Additional impact analyses were conducted for growth, soils and vegetation, and visibility impairment. These analyses are discussed in the following sections.

Growth Impacts
NTE-Reidsville is expected to employ approximately 15 to 25 full-time people, most of which are expected to come from the existing local population. Therefore, this project is not expected to cause a significant increase in growth in the area.

Soils and Vegetation
The facility is located the northern piedmont area of North Carolina. The local geography is gently rolling terrain with a mix of forests, agricultural crops, and herbaceous vegetation. Section 7.3 of the modeling report provides a detailed discussion of the expected impacts on soils and vegetation in the project area. In summary, modeled impacts are well below USEPA established thresholds for soil and vegetation effects; therefore, the NTE-Reidsville project is not expected to cause any detrimental impacts to soils or vegetation in the area.

Class II Visibility Impairment Analysis
A Level 1 and Level 2 VISCREEN (Version 1.01) analysis was conducted to determine if the NTE-Reidsville project is expected to affect any visibility sensitive areas near the project. The Pilot Mountain State Park in North Carolina was identified to be of interest with respect to visibility impacts. The Level 2 visibility analysis results provided in the modeling report show that the expected impacts to visibility will be well below the USEPA criteria for significant impacts.

Class I Area - Additional Requirements
There are six Class I areas within 300 km of the NTE-Reidsville project – Dolly Sods Wilderness Area, James River Face Wilderness Trail, Linville Gorge Wilderness, Otter Creek Wilderness, Shenandoah National Park, and Shining Rock Wilderness. The Federal Land Manager for each of those areas was contacted and none of them required any analysis; therefore, no analysis was conducted by the applicant.

Class I SIL Analysis
AERMOD was used to estimate impacts for the Class I SIL analysis. Even though the distance to the closest Class I area to NTE-Reidsville, James River Face Wilderness Trail, exceeds 50 km, the threshold distance at which a long-range transport model is typically used, receptors were conservatively placed at 50 km from the NTE-Reidsville facility. NO_2, PM_{10}, and $PM_{2.5}$ all modeled below the USEPA-established Class I SILs, and thus no Class I increment modeling was required. Table 6 provides the results of the SIL modeling.

Table 6 – Class I SIL Modeling Results (μg/m^3)

Pollutant	Averaging Period	Turbine Option	Max. Impact at 50 km	EPA SIL	% of SIL
NO_2	Annual	Mitsubishi	0.008	0.1	8
		Siemen	0.018		18
PM_{10}	24-hour	Mitsubishi	0.039	0.3	13
		Siemen	0.037		12
	Annual	Mitsubishi	0.004	0.2	2
		Siemen	0.004		2
$PM_{2.5}$	24-hour	Mitsubishi	0.051	0.07	73
		Siemen	0.047		67
	Annual	Mitsubishi	0.005	0.06	8

		Siemen	0.005		8

PSD Air Quality Modeling Result Summary
Based on the PSD air quality ambient impact analysis performed, the proposed NTE Energy's Carolinas II, LLC facility will not cause or contribute to any violation of the Class II NAAQS, PSD increments, Class I increments, or any FLM AQRVs. Tables showing the source parameters and emission rates used in the modeling are provided in the attached tables.

3-15-2017 - NTE Reidsville Energy Center Model Input (NAD83, Zone 17)

Source ID	Source Description	Easting (X)	Northing (Y)	Base Elevation (ft)	Stack Height (ft)	Temp (F)	Exit Velocity (ft/sec)	Stack Diameter (ft)	NO2 (lb/hr)	NOX (lb/hr)	PM25 (lb/hr)	PM10 (lb/hr)	CO (lb/hr)
ES1a	Mitsubishi Turbine	604782.56	4021716.98	789.8	160.0	160.00	35.30	23.0	47.20	47.20	19.40	19.40	1477.90
ES1b	Siemens Turbine	604782.56	4021716.98	789.8	150.0	174.00	41.78	22.0	112.50	112.50	19.00	19.00	384.00
ES2	Aux Boiler	604764.29	4021720.25	787.7	90.0	300.00	27.91	4.5	0.85	0.85	0.60	0.60	3.15
ES3	Fire Water Pump	604820.29	4021710.77	813.3	20.0	960.00	54.29	1.0	0.90	0.05	0.05	0.05	0.26
ES4	Diesel Generator	604798.06	4021622.90	804.2	45.0	894.00	168.82	1.2	8.69	0.50	0.15	0.15	2.92
ES5_1	Cooling Tower Cell 1	604875.16	4021639.39	801.9	48.6	103.00	27.55	30.0	0.00	0.00	1.43E-04	5.69E-02	0.00
ES5_2	Cooling Tower Cell 2	604889.35	4021650.75	804.4	48.6	103.00	27.55	30.0	0.00	0.00	1.43E-04	5.69E-02	0.00
ES5_3	Cooling Tower Cell 3	604902.84	4021660.33	803.8	48.6	103.00	27.55	30.0	0.00	0.00	1.43E-04	5.69E-02	0.00
ES5_4	Cooling Tower Cell 4	604917.39	4021670.61	803.8	48.6	103.00	27.55	30.0	0.00	0.00	1.43E-04	5.69E-02	0.00
ES5_5	Cooling Tower Cell 5	604931.94	4021680.56	802.7	48.6	103.00	27.55	30.0	0.00	0.00	1.43E-04	5.69E-02	0.00
ES5_6	Cooling Tower Cell 6	604945.43	4021690.86	804.4	48.6	103.00	27.55	30.0	0.00	0.00	1.43E-04	5.69E-02	0.00
ES5_7	Cooling Tower Cell 7	604959.27	4021700.79	805.2	48.6	103.00	27.55	30.0	0.00	0.00	1.43E-04	5.69E-02	0.00
ES6	Fuel Gas Heater	604857.98	4021567.08	770.4	20.0	250.00	22.67	2.0	0.11	0.11	0.06	0.06	0.33

NO2 represents the maximum hourly NO2 emission rate
NOx represents the annual NO2 emission rate.

NTE Modeled TAP Emissions

Source Description	Ammonia (lb/hr)	Benzene (lb/hr)	Chromic Acid (lb/hr)	Formaldehyde (lb/hr)	Sulfuric Acid (lb/hr)
Mitsubishi Turbine	2.52E+01	2.85E-02	0.00E+00	1.69E+00	6.49E+00
Siemens Turbine	2.55E+01	3.08E-02	0.00E+00	1.82E+00	2.95E+00
Aux Boiler	2.67E-01	1.74E-04	0.00E+00	6.25E-03	2.00E-02
Fire Water Pump	0.00E+00	1.96E-03	6.30E-06	2.48E-03	9.00E-02
Diesel Generator	0.00E+00	1.00E-02	4.00E-05	1.10E-03	3.00E-03
Cooling Tower Cell 1	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Cooling Tower Cell 2	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Cooling Tower Cell 3	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Cooling Tower Cell 4	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Cooling Tower Cell 5	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Cooling Tower Cell 6	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Cooling Tower Cell 7	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Fuel Gas Heater	2.82E-02	1.85E-05	0.00E+00	6.62E-04	2.00E-03

NTE Energy Reidsville Energy Center Off-Site Source Model Input Data (All Sources within 10km of NTE Site) (NAD83, Zone 17)

Source ID	Plant Name	Easting (X) (m)	Northing (Y) (m)	Base Elevation (ft)	Stack Height (ft)	Temperature (°F)	Exit Velocity (ft/sec)	Stack Diameter (ft)	Potential NO2 (lb/hr)	Potential PM25 (lb/hr)	Distance from NTE (km)	State	County
08731_1	Duke Energy Carolinas, LLC-Rockingham Co Comb. Turb.	605029.79	4021241.38	816.77	60.00	1100.00	85.90	24.70	294.00	23.00	0.54	NC	Rockingham
08731_2	Duke Energy Carolinas, LLC-Rockingham Co Comb. Turb.	605028.02	4021199.21	816.96	60.00	1100.00	85.90	24.70	294.00	23.00	0.57	NC	Rockingham
08731_3	Duke Energy Carolinas, LLC-Rockingham Co Comb. Turb.	605026.96	4021158.45	816.90	60.00	1100.00	85.90	24.70	294.00	23.00	0.61	NC	Rockingham
08731_4	Duke Energy Carolinas, LLC-Rockingham Co Comb. Turb.	605025.54	4021116.28	816.93	60.00	1100.00	85.90	24.70	294.00	23.00	0.65	NC	Rockingham
08731_5	Duke Energy Carolinas, LLC-Rockingham Co Comb. Turb.	605024.12	4021074.47	816.70	60.00	1100.00	85.90	24.70	294.00	23.00	0.69	NC	Rockingham
08731_6	Duke Energy Carolinas, LLC-Rockingham Co Comb. Turb.	605145.00	4021067.00	819.06	20.00	1300.00	235.00	0.42	10.40	0.74	0.74	NC	Rockingham
08731_7	Duke Energy Carolinas, LLC-Rockingham Co Comb. Turb.	605145.00	4021067.00	819.06	40.40	892.70	153.00	1.80	66.62	3.86	0.74	NC	Rockingham
08731_8	Duke Energy Carolinas, LLC-Rockingham Co Comb. Turb.	605145.00	4021067.00	819.06	20.00	935.00	83.50	0.42	9.60	0.68	0.74	NC	Rockingham
09113_1	Transcontinental Gas Pipe Line Company, LLC - Station 160	605859.86	4022629.33	848.72	21.00	779.00	77.30	0.70	2.87	0.03	1.41	NC	Rockingham
09113_2	Transcontinental Gas Pipe Line Company, LLC - Station 160	605843.80	4022614.31	849.31	21.00	779.00	77.30	0.70	2.87	0.03	1.39	NC	Rockingham
09113_3	Transcontinental Gas Pipe Line Company, LLC - Station 160	605862.97	4022618.97	849.44	14.00	500.00	18.10	1.00	0.25	3.12	1.41	NC	Rockingham
09113_4	Transcontinental Gas Pipe Line Company, LLC - Station 160	605908.93	4022616.96	849.48	23.00	679.00	117.90	1.70	47.23	0.72	1.44	NC	Rockingham
09113_5	Transcontinental Gas Pipe Line Company, LLC - Station 160	605858.74	4022561.75	849.44	28.00	773.00	163.90	2.00	46.60	0.71	1.37	NC	Rockingham
09113_6	Transcontinental Gas Pipe Line Company, LLC - Station 160	605849.06	4022550.83	849.51	34.00	707.00	99.40	2.40	23.60	1.13	1.35	NC	Rockingham
09113_7	Transcontinental Gas Pipe Line Company, LLC - Station 160	605839.70	4022540.53	849.44	34.00	707.00	99.40	2.40	23.60	1.13	1.34	NC	Rockingham
09113_8	Transcontinental Gas Pipe Line Company, LLC - Station 160	605831.59	4022532.10	849.44	34.00	707.00	99.40	2.40	23.60	1.13	1.33	NC	Rockingham
09113_9	Transcontinental Gas Pipe Line Company, LLC - Station 160	605805.06	4022464.39	849.21	49.00	676.00	76.40	4.00	38.20	1.82	1.27	NC	Rockingham
09113_10	Transcontinental Gas Pipe Line Company, LLC - Station 160	605802.25	4022451.59	849.28	49.00	676.00	76.40	4.00	38.20	1.82	1.26	NC	Rockingham
09113_11	Transcontinental Gas Pipe Line Company, LLC - Station 160	605785.76	4022430.36	849.18	30.00	912.00	76.40	11.20	12.08	0.81	1.23	NC	Rockingham
09113_12	Transcontinental Gas Pipe Line Company, LLC - Station 160	605903.47	4022610.85	849.44	23.00	679.00	117.90	1.70	47.23	0.72	1.43	NC	Rockingham
09113_13	Transcontinental Gas Pipe Line Company, LLC - Station 160	605898.97	4022606.04	849.41	23.00	679.00	117.90	1.70	47.23	0.72	1.43	NC	Rockingham
09113_14	Transcontinental Gas Pipe Line Company, LLC - Station 160	605892.88	4022599.62	849.34	23.00	679.00	117.90	1.70	47.23	0.72	1.42	NC	Rockingham
09113_15	Transcontinental Gas Pipe Line Company, LLC - Station 160	605888.06	4022593.52	849.31	23.00	679.00	117.90	1.70	47.23	0.72	1.41	NC	Rockingham
09113_16	Transcontinental Gas Pipe Line Company, LLC - Station 160	605882.60	4022588.06	849.28	23.00	679.00	117.90	1.70	47.23	0.72	1.40	NC	Rockingham
09113_17	Transcontinental Gas Pipe Line Company, LLC - Station 160	605876.82	4022581.96	849.28	23.00	379.00	117.90	1.70	47.23	0.72	1.39	NC	Rockingham
09113_18	Transcontinental Gas Pipe Line Company, LLC - Station 160	605869.97	4022574.23	849.34	28.00	773.00	163.90	2.00	46.60	0.71	1.38	NC	Rockingham
09113_19	Transcontinental Gas Pipe Line Company, LLC - Station 160	605864.97	4022567.99	849.38	28.00	773.00	163.90	2.00	14.60	0.71	1.38	NC	Rockingham
10200_1	Rockingham County Landfill	603879.00	4024835.00	690.19	10.00	72.00	0.20	1.00	2.39	0.00	3.25	NC	Rockingham
04133_1	Martin Marietta Materials, Inc. - Reidsville Quarry	614236.00	4026085.00	876.12	10.00	72.00	0.20	1.00	0.00	0.003	10.41	NC	Rockingham

Notes: