Engineering Analysis

Source Name: **C4GT, LLC** Permit No.: **52588-001**

Source Location: **State Rte 106 at Rte 685, Charles City County, Virginia** Engineer: **AMS**

Date: **March 6, 2018**

I. Introduction and Background

A. Company Background

The facility, as proposed, will be a new, combined-cycle, natural gas-fired, electrical power generating facility with a nominal net capacity of 1,060 MW. The facility will be located on an 88-acre parcel less than a half mile north-northwest of the intersection of State Route 106 (Roxbury Rd.) and State Route 685 (Chambers Rd.) 1.7 mi. southwest of Roxbury in Charles City County. The nearest residences are approximately 1,000 ft to the east, with others about a half mile to the west. The nearest grade school is the Elko Middle School located just over 5 miles away to the northwest. Other grade schools are located 8 miles south in Charles City. The nearest preschools and day cares are over 5.0 miles to the northwest and southeast of the proposed site. The nearest hospital or medical centers are in Richmond and Hopewell, over 10 miles away, as are the nearest senior care facilities. There are no Class I areas within 100 km of the proposed facility (see Table 1).

The area is in attainment for all pollutants. Since the source will be a major source, with emissions over 100 tons/yr of regulated NSR pollutants [nitrogen oxides (NO_x or NO_2), carbon monoxide (CO), volatile organic compounds (VOC), particulate matter (PM) filterable only, particulate matter less than 10 microns (PM_{10}), particulate matter less than 2.5 microns ($PM_{2.5}$)], and greenhouse gas [GHG or CO_2 equivalents (CO_2e)] over 75,000 tons/yr, Prevention of Significant Deterioration (PSD) permitting (Article 8) for those pollutants - as well as sulfuric acid mist (H_2SO_4) emissions - will be triggered. Although SO_2 did not trigger PSD permitting, emissions are greater than the exemption rate in Virginia regulations for minor New Source Review (minor NSR) (Article 6) permitting for SO_2. The source will not be major for hazardous air pollutants (HAP), so no MACT will apply, and the source will be subject to the State Toxics Rule (9 VAC 5-60-300, Rule 6-5).

Table 1 - The following table shows the distances between the proposed plant site and the closest Class I areas.

Class I area	Distance from project
Shenandoah National Park (USNPS)	152 km
James River Face Wilderness Area (USFS)	196 km
Dolly Sods Wilderness Area (USFS)	254 km
Swanquarter National Wildlife Refuge (USFWS)	239 km
Otter Creek Wilderness Area (USFS)	272 km

Site Suitability:

The facility will be located on a site that is suitable from an air pollution standpoint. The area is rural with a combination of undeveloped and transitional land (tree plantations and farms) and small businesses. Two existing electric transmission lines and a substation are less than 1 mile to the southeast. The area is supplied with a natural gas pipeline from Virginia Natural Gas Company. The site is an upland area (elevation 120-140 ft). The property contains a dammed portion of Possum Run. Additionally, the County of Charles City has certified that the location and operation of the facility are consistent with all applicable ordinances adopted pursuant to Chapter 22 (§15.2-2200 et seq.) of Title 15.2 of the Code of Virginia (see copy of the Local Government Ordinance Form in the file for the VPDES permit application – the analogous Local Governing Body Certification Form for the air permit application was not received from the county).

In accordance with Section 10.1-1307 E of the Air Pollution Control Law of Virginia, consideration has been given to the following facts and circumstances relevant to the reasonableness of the activity involved:

1. The character and degree of injury to, or interference with safety, health, or the reasonable use of property which is caused or threatened to be caused:

   The activities regulated in this permit have been evaluated consistent with 9 VAC 5-50-280 (Best Available Control Technology for pollutants subject to PSD permitting), 9 VAC 5-50-260 (Best Available Control Technology for pollutants subject to Minor New Source Review permitting), and 9 VAC 5-60-320 (Toxics Rule) and have been determined to meet these standards where applicable. Please see Section III.G for a description of the Best Available Control Technology (BACT) included in the permit. Please refer to Section III.F.2 for more information on the applicability of the Toxics Rule to the proposed facility.

   As a fossil fuel-fired steam electric generating plant having heat input greater than 250 million British thermal units (MMBtu) per hour, the proposed facility is a major stationary source according to 9 VAC 5-80-1615 C of the Virginia PSD regulations. In accordance with PSD regulations, air quality modeling was conducted to predict the maximum ambient impacts of criteria pollutants emitted by the proposed source. Class I air quality analyses are typically performed for PSD facilities within 100 kilometers of a Class I area (an area such as a national park or wildlife sanctuary). In addition, Class I modeling is also done for large sources having the capability to affect air quality at distances up to 300 kilometers. An analysis was done to determine compliance with Class I PSD increment for PM_{10}, $PM_{2.5}$, and NO_2 from both the GE turbines and the Siemens turbines. DEQ found the proposed C4GT project did not significantly contribute to a predicted violation of any applicable Class I area increment. The maximum predicted concentrations of those pollutants were below the Class I significant impact levels (SILs) so no additional air quality analysis was required for Class I area impact. See attached Modeling Memo, Section C.

   The Class II (all other areas not designated as Class I areas) preliminary modeling analysis, predicted that the maximum ambient air impacts from CO (1-hour and 8-hour averaging periods), NO_2 (annual averaging period) and PM_{10} (24-hour and annual averaging periods) were below applicable modeling SILs. No further analyses were required for these pollutants at the indicated averaging periods. However, modeled concentrations for NO_2 (1-hour averaging period) exceeded the applicable SILs and a full impact analysis was done. Also, a full impact analysis was done for $PM_{2.5}$ (24-hour and annual averaging periods) because VADEQ does not currently have state-specific SILs for the purpose of excluding a project from performing a full impact analysis. Therefore, a cumulative impact analysis for these pollutants and averaging periods was necessary. The predicted impacts for NO_2 and $PM_{2.5}$ from the cumulative impact analysis were less than the applicable National Ambient Air Quality Standards (NAAQS) and Class II area PSD increments. Hence, the proposed project does not cause or significantly contribute to a predicted violation of any applicable NAAQS or Class II area PSD increment. See attached Modeling Memo, Sections A and B.

   Ozone was also modeled and the predicted worst-case daily impact from the facility was below the 8-hour ozone NAAQS. See attached Modeling Memo, Section D.

   Results of modeling conducted for emissions from the proposed facility show compliance with the health-based NAAQS for all pollutants. Furthermore, single source and cumulative modeling analyses indicate that the proposed project will not result in a violation of any PSD increment. Accordingly, approval of the proposed permit is not expected to cause injury to or interference with safety, health, or reasonable use of property.

   The emissions of toxic pollutants from electric generating units that are not major for hazardous air pollutants (HAPs), such as those proposed by C4GT, are subject to the standards in 9 VAC 5-60-300 et seq. C4GT calculated the emissions of toxic pollutants from all of the emission units proposed for the site. C4GT modeled emissions of toxic pollutants for which proposed emissions exceeded the thresholds in 9 VAC 5-60-320 (acrolein and formaldehyde from both the GE and Siemens power blocks on an hourly and annual basis, and, additionally, cadmium, chromium, and nickel from the Siemens power block on an annual basis). Modeling demonstrated that proposed emissions of these toxics pollutants are well below the associated Significant Ambient Air Concentrations (SAACs). See attached Modeling Memo, Section B for Toxics Analysis.

A visibility analysis would be done to assess the potential for visual plume impacts in Class II areas within 50 km of the projected site, however there are no protected areas near the C4GT site. The facility is required to use clean-burning fuels and air pollution control equipment, and is limited to opacity not to exceed 10% at the turbine stacks. See attached Modeling Memo, Section B for Additional Impact Analyses.

The results of an analysis to determine the impact of facility emissions on vegetation and soils has demonstrated that the maximum predicted concentrations of SO_2, NO_2, PM_{10}, and CO were below the minimum reported levels at which damage or growth effects to vegetation may occur. And, based on the soil types in the vicinity of the proposed facility and the emissions from the facility, no adverse impact on local soils is anticipated. See attached Modeling Memo, Section B for Additional Impact Analyses.

2. The social and economic value of the activity involved:

   The social and economic value of the facility submitting the application has been evaluated relative to local zoning requirements. The local government official has deemed this activity not inconsistent with local ordinances. A copy of the signed Local Government Ordinance Form is included in the file.

   The proposed C4GT Power Station will generate electricity using only clean-burning natural gas. Construction of clean-burning, efficient generation plants, such as the proposed facility, creates the potential for regional SO_2 and NO_x reductions resulting from displacement of older, more-polluting forms of electricity generation.

   The Charles City County Board of Supervisors supports the construction of the facility and anticipates the placement of the facility in this location will be an economic boon to the region in terms of jobs and taxes.

3. The suitability of the activity to the area in which it is located:

   Consistent with §10.1-1307 E. of the State Air Pollution Control Law, the activities regulated in this permit are deemed suitable as follows:

   a. <u>Air Quality characteristics and performance requirements defined by SAPCB regulations:</u> This permit is written consistent with existing applicable regulations. The proposed facility is a source of toxic air pollutant emissions and has been modeled and shows compliance with the applicable SAACs. The emissions for criteria pollutants associated with this permit have likewise been modeled and have been shown through modeling to not cause or contribute to a violation of the ambient air quality standards or allowable increments within any Class I or Class II areas.

   b. <u>The health impact of air quality deterioration which might reasonably be expected to occur during the grace period allowed by the Regulations or the permit conditions to fix malfunctioning air pollution control equipment:</u> The permit contains a requirement to notify the Piedmont Regional Office within four business hours of the discovery of any malfunction of pollution control equipment (Condition 79).

c. <u>Anticipated impact of odor on surrounding communities or violation of the SAPCB Odor Rule:</u> No violation of odor requirements is anticipated as a result of the proposed project.

4. The scientific and economic practicality of reducing or eliminating the discharge resulting from the activity: The Minor New Source Review program, as well as the PSD and Non-Attainment Major New Source Review programs, require consideration of levels of control technology that are written into regulation to define the level of scientific and economic practicality for reducing or eliminating emissions. By properly implementing the Regulations through the issuance of the proposed permit, the staff has addressed the scientific and economic practicality of reducing or eliminating emissions associated with this project.

   The permit requires numerous pollution control strategies that will result in reduction of emissions from the combustion turbines and associated equipment. These include technologies such as the use of clean fuels with low sulfur content, good combustion practices (GCP), high combustion efficiency, and clean-burning "low-NO_x" burners as well as add-on control (SCR for NO_x removal and an Oxidation Catalyst for CO, VOC, and VOC toxic pollutant control). Other measures have been included in the draft permit, such as a requirement to use ultra-low sulfur diesel oil (no more than 0.0015% sulfur content by weight) in emergency equipment and to monitor equipment leaks in the circuit breakers and natural gas piping components. Feasibility of obtaining further emission reductions was reviewed through the rigorous "top-down" BACT requirements of PSD review. No additional controls were found to be technically and economically feasible.

B. Proposed Project Summary

The proposed project will be a new combined-cycle electrical power generating facility utilizing two combustion turbines each with a duct-fired heat recovery steam generator (HRSG) with a common reheat condensing steam turbine generator (2 on 1 configuration). **Option 1** is proposed to be two GE 7HA.02 turbines each with a 475 MMBtu/hr HHV duct-fired HRSG resulting in a project with a nominal net generating capacity of 1,060 MW. **Option 2** is proposed to be two Siemens SGT6-8000H turbines each with a 991 MMBtu/hr HHV duct-fired HRSG resulting in a project with a nominal net generating capacity of 1,060 MW. The proposed fuel for the turbines and duct burners is pipeline-quality natural gas. Emissions from the turbines will be controlled by the use of low carbon fuels and high efficiency design (for GHG), clean fuels and GCP (for PM, PM_{10} and $PM_{2.5}$), SCR and dry low NO_x burners (for NO_x), and oxidation catalyst (for CO and VOC). Other equipment at the site, including a natural gas-fired auxiliary boiler and dew point heater, a cooling tower, a diesel-fired emergency fire water pump, and a diesel-fired emergency generator are also proposed and will be subject to emission controls. Natural gas piping components and electrical circuit breakers potentially emit GHG pollutants (expressed as carbon dioxide equivalents, or CO_2e) and they will also be covered in the permit.

Table 2 below quantifies the facility-wide emissions expected from the power plant.

Table 2 - Expected emissions from the proposed facility are as follows:

Pollutant	**Option 1**: GE Emissions (tons/yr)	**Option 2**: Siemens Emissions (tons/yr)
NO_x	295	296
CO	223	293
SO_2	39	39
VOC	86	114
PM (filterable only)	180	239
PM_{10}	156	216
$PM_{2.5}$	156	216
CO_2e	4,123,597	4,277,303
H_2SO_4	23	24
Acrolein	0.20	0.18

Pollutant	**Option 1**: GE Emissions (tons/yr)	**Option 2**: Siemens Emissions (tons/yr)
Formaldehyde	7.1	7.3
Cadmium	(below exemption limit)	0.010
Chromium	(below exemption limit)	0.013
Nickel	(below exemption limit)	0.019

Note: Emissions of regulated toxic pollutants other than those listed above are less than permitting exemption thresholds and were therefore not included in the permit.

C. Process and Equipment Description

Equipment to be Constructed			
Ref. No.	**Equipment Description**	**Rated Capacity**	**Federal Requirements**
Two on one power block with two natural gas-fired combustion turbine generators, each with a duct-fired heat recovery steam generator (HRSG) , providing steam to a common steam turbine generator			
CT-1	**Option 1**: GE 7HA.02 combustion turbine generator with duct burner (natural gas-fired)	3,482 MMBtu/hr CT (HHV) 475 MMBtu/hr DB (HHV)	NSPS, Subpart KKKK
	Option 2: Siemens SGT6-8000H combustion turbine generator with duct burner (natural gas-fired)	3,116 MMBtu/hr CT (HHV) 991 MMBtu/hr DB (HHV)	NSPS, Subpart KKKK
CT-2	**Option 1:** GE 7HA.02 combustion turbine generator with duct burner (natural gas-fired)	3,482 MMBtu/hr CT (HHV) 475 MMBtu/hr DB (HHV)	NSPS, Subpart KKKK
	Option 2: Siemens SGT6-8000H combustion turbine generator with duct burner (natural gas-fired)	3,116 MMBtu/hr CT (HHV) 991 MMBtu/hr DB (HHV)	NSPS, Subpart KKKK
STG (no emissions)	**Option 1:** GE steam turbine generator	356 MW at ISO with DB	None
	Option 2: Siemens steam turbine generator	473 MW at ISO with DB	None
Ancillary Equipment			
B-1	Auxiliary Boiler (natural gas-fired)	105 MMBtu/hr (HHV)	NSPS, Subpart Db
DPH-1	Dew Point Heater (natural gas-fired)	16 MMBtu/hr (HHV)	NSPS, Subpart Dc
EG-1	Emergency Generator (S15 ULSD)	2500 kW	NSPS IIII, MACT ZZZZ
FWP-1	Fire Water Pump (S15 ULSD)	315 bhp	NSPS IIII, MACT ZZZZ
CWT-1	Mechanical draft cooling tower (18 cell)	348,500 gallons of water/min	None
CB-1 thru CB-4	Four Electrical Circuit Breakers	1,900 lbs SF_6 per breaker	None
CB-5 and CB-6	Two Generator Breakers	30 lbs SF_6 per breaker	None
T-1	ULSD storage tank	3,000 gallons	None
T-2	ULSD storage tank	400 gallons	None
FUG-1	Fugitive equipment leaks	--	None

1. Combustion Turbine Generators with duct-fired HRSG (CT-1 & CT-2)

   a. <u>Combustion Turbines (CT)</u>

      The source has proposed two power block options: **Option 1**- the installation of two 352 MW GE 7HA.02 CTs in combined-cycle mode or, **Option 2**- the installation of two 306 MW Siemens SGT6-8000H CTs in combined-cycle mode.

      The gas turbine is the main component of a combined-cycle power system. Hot exhaust gases from the combustion chamber are ducted to a HRSG to create steam to power the steam turbine. Duct burners provide supplementary heat to boost steam production during warmer temperatures or if increased power is needed.

Both of the CT models, Siemens and GE, are combined cycle units. Combined cycle power plants are highly efficient compared to peaking units, even at variable loads. Which model gets installed will depend on the configuration that will be best suited for projected operational demands of the plant.

- Option 1: The GE turbines and duct burners would operate more as baseload units, at the maximum power for most of the year. This configuration is optimal for efficiency so large duct burners are not needed since the unit will be in steady-state operation, with minimal load changes. If this configuration is chosen, C4GT will be able to meet the need for baseload power should the market be favorable to this type of power plant.
- Option 2: : The Siemens configuration for the C4GT project could allow the plant to efficiently match the needs of the evolving Virginia electric marketplace, which will include significantly more intermittent solar generation in the years ahead. This is because the Siemens configuration is able to operate with lower baseload capacity when renewable power sources are available, but also at higher peaking capacity, when renewable power sources are not available. The larger duct burners provide operational flexibility as they are able to quickly provide additional power on very hot days when the turbines are not able to maximize output.

Efficient, natural gas-fired, combined cycle units have reduced operating costs[1] when cycling is kept to a minimum (baseload or load following operation). Minimizing the frequency of startup and shutdown of the combined cycle turbines reduces emissions and boosts efficiency. Some shutdowns are inevitable as needed for maintenance and repairs.

Alternate Operating Scenarios: Besides, startup and shutdown, the permittee requests to be allowed two maintenance events requiring alternate operating scenarios for the CTs, i.e., turbine tuning and turbine blade water washing.

i. Turbine tuning – Turbine tuning consists of adjusting the air-to-fuel ratio under a wide range of load and atmospheric conditions in order to optimize turbine performance, while minimizing emissions. On a periodic and as-needed basis, planned maintenance shall include tuning of the turbines. A tuning event could last up to 18 hours. During tuning, the turbines might not be able to meet the normal lb/hr or other short-term emission limits on a three-hour average (or one-hour average for NO_x) due to fluctuations in air flow and fuel flow during tuning. The permittee requests an alternate time period of a calendar day for short term NO_x and CO limits during this scenario (units would be lb/turbine/calendar day). Approximately 96 hours per year per turbine is expected to be utilized for this maintenance.

ii. Water washing of turbine blades – When the turbine blades become dirty over time, the efficiency of the turbine declines, so it is necessary to wash the blades on a periodic basis. Water washing involves spraying water into the turbine while it is operating and is expected to take no more than 60 minutes per event per turbine. This process could temporarily disrupt the combustion characteristics of the turbine and affect the inlet concentrations of NO_x and CO to a point where it would not be expected to meet the normal lb/hr or other short-term emission limits over a three hour averaging period (or one-hour average for NO_x). The permittee requests an alternate time period of a calendar day for short term NO_x and CO limits during this scenario (units would be lb/turbine/calendar day). Approximately 52 water wash events are predicted per year to accomplish this maintenance.

1 Kumar, N, et al. *Power Plant Cycling Costs*. NREL, 2012, *Power Plant Cycling Costs*, https://www.nrel.gov/docs/fy12osti/55433.pdf.

b. Heat Recovery Steam Generators (HRSG) with Duct Burners (DB)

The proposed facility will use two HRSGs, one for each CT, which will use waste heat to produce additional electricity, thus increasing plant efficiency. Each HRSG will act as a heat exchanger to derive heat energy from the CT exhaust gas to produce steam that will be used to drive a Steam Turbine generator (STG). Steam production in the HRSGs will be augmented using DBs that will be fired by natural gas. The proposed DBs will have a firing rate of 475 MMBtu/hr each for the GE turbines and 991 MMBtu/hr each for the Siemens turbines. The heat recovered is used in the combined-cycle plant for additional steam generation and natural gas/feedwater heating. Each HRSG will include high-pressure superheaters, a high-pressure evaporator, high-pressure economizers, reheat sections (to reheat partially expanded steam), an intermediate-pressure superheater, an intermediate-pressure evaporator, an intermediate-pressure economizer, a low-pressure superheater, a low-pressure evaporator, and a low-pressure economizer. The water-cooled condenser will condense the steam exhausting from the STG.

c. Steam Turbine Generator (STG)

The proposed project includes one reheat, condensing steam turbine generator (STG) designed for variable pressure operation. The high-pressure portion of the STG receives high-pressure superheated steam from the HRSGs, and exhausts to the reheat section of the HRSGs. The steam from the reheat section for the HRSGs is supplied to the intermediate-pressure section of the turbine, which expands to the low-pressure section. The low-pressure STG also receives excess low-pressure superheated steam from the HRSGs and exhausts to the water-cooled condenser. The STG set associated with the GE turbines is designed to produce up to approximately 356 MW of electrical output at ISO conditions with duct firing and the STG set associated with the Siemens turbines is designed to produce up to approximately 473 MW of electrical output at ISO conditions with duct firing. No pollutants are emitted from the STG.

2. Ancillary Equipment

a. Auxiliary Boiler (B-1)

The proposed facility will include a 105.0 MMBtu/hr, natural gas-fired, auxiliary boiler. The auxiliary boiler will provide steam to the STG at startup and at cold or warm starts to warm up the HRSG. The steam from the auxiliary boiler will not be used to augment the power generation of the CTs or STG. The boiler is proposed to operate up to 8760 hrs/yr.

b. Dew Point Heater (DPH-1)

The proposed facility will include a 16 MMBtu/hr, natural gas-fired, dew point heater. The heater will be used to warm up the incoming natural gas fuel to prevent freezing of the gas regulating valves under certain gas system operating conditions. The heater is proposed to operate up to 8760 hrs/yr.

c. Diesel-Fired Emergency Generator (EG-1)

The proposed facility will include a 2,500 kW diesel-fired emergency generator that will be operated up to 500 hours per year (including 100 hrs of maintenance checks and readiness testing). The emergency generator will provide power in emergency situations for turning gears, lube oil pumps, auxiliary cooling water pumps, and water supply pumps. The emergency diesel generator is not intended to provide sufficient power for a black start, peak shaving, or non-emergency power.

d. Diesel-Fired Fire Water Pump (FWP-1)

The proposed project will include a 315 bhp diesel-fired generator operated as a fire water pump driver. The unit will be limited to 500 hours per year, including monthly testing and maintenance (not to exceed 100 hours per year).

e. Cooling Tower (CWT-1)

An 18-cell mechanical draft cooling tower will be incorporated to provide cooling water to the condenser to condense the exhaust steam from the steam turbine.

f. Circuit Breakers (CB-1 through CB-6)

The proposed project will include four switchyard circuit breakers (holding 1900 lbs of the greenhouse gas sulfur hexafluoride (SF_6) per unit). There will be two low-side generator circuit breakers (holding 30 lbs of SF_6 per unit).

g. Distillate Oil Storage Tanks (T-1 and T-2)

The proposed project will include one 3,000-gallon and one 400-gallon, fixed-roof, horizontal, distillate oil storage tank to provide fuel for the emergency generator and fire water pump, respectively. These units were found to be insignificant with respect to VOC emissions.

h. Fugitive equipment leaks (FUG-1)

The proposed project will be supplied by natural gas piping components. Some leakage of natural gas (primarily methane, which is a greenhouse gas) may occur at valves, flanges and other connections, and during repairs, venting, etc.

D. Project Schedule

Date permit application received in region	June 21, 2016 (amended February 3, 2017 with emission calculations and April 21, 2017 with modeling, revised November 15, 2017)
Date application was deemed complete	November 15, 2017
Proposed construction commencement date	June 2018
Proposed startup date	June 2021

II. Emissions Calculations (see attached spreadsheets for detailed emission calculations)

Proposed emissions are primarily products of combustion from the combined cycle units and duct burners. There are also emissions from the auxiliary boiler, dew point heater, emergency generator, emergency fire water pump, cooling tower, circuit breakers, and piping components. Permitted emission limits reflect BACT (see section III.G for BACT analysis).

Compliance with the annual emission limits for NO_x and CO from the combined cycle units and duct burners will be based on CEMS data. Compliance with the annual SO_2 and H_2SO_4 limits will be based on fuel throughput and the sulfur content of the fuel.

The permit will include initial testing for PM, PM_{10}, $PM_{2.5}$, and VOC. The permittee will conduct an initial stack test for those pollutants and, based on the results, will develop approved emission factors and, with fuel throughput monitoring, will perform monthly calculations to determine a 12-month rolling total to show compliance with annual emission limits for these pollutants from the combustion turbines and associated duct burners. Particulate emissions from natural gas are mainly due to incomplete combustion of the low-ash gaseous fuel and are PM_{10} or smaller, however ammonia from the SCR and sulfates from the SCR and oxidation catalyst also contribute to PM_{10} and $PM_{2.5}$ emissions. Incomplete combustion results in higher VOC and CO emissions. Compliance with the CO emission limit is an indication of compliance with the VOC limits. The indication provided by compliance with the CO emission limit in conjunction with testing every five years (Federal Operating Permit requirement) ensures the relationship between CO and VOC remains accurate over the life of the units and provides a reasonable assurance of compliance.

The turbines will also have a lb CO_2e/MWh limit and a Btu/kWh heat rate limit to show compliance with the energy-efficiency requirements for GHG BACT and NSPS Subpart TTTT. Compliance with the Btu/kWh limit will be achieved with a one-time power block heat rate evaluation. Compliance with the lb/MWh limit will be achieved by monitoring the electrical energy output and the mass emissions of CO_2e on a monthly basis. CO_2 will be monitored using CEMS or by approved calculation methods. N_2O and CH_4 emissions will be calculated using 40 CFR Part 98 factors. Total CO_2, N_2O and CH_4, along with their associated Global Warming Potential factors, will determine CO_2e emissions (see section III.A).

Emissions from startup and shutdown (SU/SD) were included in the annual permit emissions limits for the combustion turbines, so separate annual limits will not be included. During SU/SD, some post-combustion controls (like SCR and OxCat) are not working at the optimum level of control and optimal stack temperatures have not been achieved, however, during these periods, the turbines and duct burners are also not operating at their highest output and other emissions may be reduced for that reason. Therefore, to properly quantify annual emissions, it is important to consider estimated emissions during SU/SD. Worst case annual emissions were based on the turbines and duct burners operating at either 8,760 hrs/yr without SU/SD, or with the turbines and duct burners operating for either GE: @ 8,492 hrs/yr or Siemens: @ 8,389 hrs/yr, plus SU/SD emissions for the remaining hours of the year. The facility was not given a limit on the total number of hours of SU/SD, but rather the estimated amount of time was factored into the annual emission to determine worst-case annual emissions. BACT applies during SU/SD and BACT includes operation of emission controls and using best practices to minimize emissions (See Section III.G for more information). Short term limits for CO, NO_x, and VOC during SU/SD and CO and NO_x from alternative operating scenarios are included in the permit and compliance with those limits will be based on CEMS data (VOC compliance is based on development of a CO/VOC correlation so that, if the CO CEMS shows compliance with the CO limit, then VOC is in compliance with the VOC limit).

Emissions from the auxiliary boiler, dew point heater, and cooling tower were based on 8,760 hrs/yr operation. The emergency generator and fire water pump are permitted to operate no more than 500 hrs/yr.

Fugitive emissions from equipment leaks were based on emission factors from 40 CFR 98 Subpart W, Table W-1A on an annual basis.

Estimated emissions from the circuit breakers were based on a maximum annual leakage rate of 0.5% on an annual basis but compliance with those limits will be based on work practice standards since actual measurement of the emissions are not feasible.

III. Regulatory Review

The proposed project is a major new source with projected, permitted, annual emissions greater than 100 tons of several criteria pollutants (see Table 2 in Section I.B above).

A. Greenhouse Gas Emissions Applicability Review: Under the PSD program, new major stationary sources that have the potential to emit 75,000 tons of CO_2e are required to apply BACT for GHG if PSD is triggered for other pollutants. The total CO_2e is based on taking the mass emissions of each GHG pollutant and multiplying by its Global Warming Potential (GWP). These GWP factors are as follows: CO_2: 1; CH_4: 25; N_2O: 298; SF_6: 22,800. The first three GHG pollutants are primarily from fuel burning and the SF_6 is from semi-conductors/circuit breakers. This facility has electrical circuit breakers which contain SF_6.

Since the C4GT facility will be a PSD source for several other pollutants, and permitted CO_2e emissions will be greater than 75,000 tons, the source must apply BACT for CO_2e emissions.

On October 23, 2015, EPA issued a revised Final Rule for NSPS Subpart TTTT – Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Generating Units (40 CFR 60.5508 et seq.). See Section III.C.5 below for more details.

B. Major New Source Review PSD Permitting: The source is PSD-major for PM, PM_{10}, $PM_{2.5}$, NO_x, CO, and VOC (see Table 3 below). Because one or more pollutants are subject to PSD, other pollutants at the source (SO_2, lead, and H_2SO_4) need to be evaluated for PSD applicability based on their significance level. PSD review was not triggered for lead or SO_2. H_2SO_4 exceeded the PSD significance level so the facility will be subject to PSD for H_2SO_4 in addition to the other pollutants mentioned above. The source is required to apply BACT for these pollutants. BACT for these pollutants is discussed in Section III.G.

Table 3 - PSD Permitting applicability

Pollutant	Option 1 GE (TPY)	Option 2 Siemens (TPY)	PSD Major Threshold (TPY)*****	Over Major Threshold?	PSD Significance Rate (TPY)******	PSD Required?
PM	180	239	100	**Yes**	25	**Yes**
PM_{10}	156	216	100	**Yes**	15	**Yes**
$PM_{2.5}$	156	216	100	**Yes**	10	**Yes**
NO_x	295	296	100	**Yes**	40	**Yes**
CO	223	293	100	**Yes**	100	**Yes**
SO_2	39	39	100	No	40	No
VOC	86	114	100	**Yes**	40	**Yes**
CO_2e	4,123,597	4,277,303	—	**Yes**	75,000	**Yes**
Lead	0.02	0.02	100	No	0.6	No
H_2SO_4	23	24	100	No	7	**Yes**

*****Major Threshold levels from definition of “Major stationary source” in 9 VAC 5-80-1615C
******PSD significance values from definition of “significant” in 9 VAC 5-80-1615C

C. NSPS Requirements:

1. Subpart KKKK: The combustion turbines (CT-1, CT-2) are subject to NSPS Subpart KKKK (Standards of Performance for Stationary Combustion Turbines) which requires the source to meet NO_x and SO_2 standards. The source must meet a NO_x limit of 15 ppm @ 15% O_2 or 0.43 lb/MWh when burning natural gas. The source proposes the use of low NO_x burners and SCR to control NO_x emissions. The source will put NO_x CEMS on the turbine stacks to show compliance with the NO_x limits. NO_x emissions from the proposed combustion turbines are expected to be around 2 ppmvd when burning natural gas which is below the NSPS standard. NO_x BACT is discussed in more detail in Section III.G.

   The source proposes using low-sulfur fuel (natural gas) to control SO_2 and H_2SO_4 from the turbines and duct burners. To be in compliance with NSPS KKKK, they must not exceed 0.06 lb SO_2/MMBtu or 0.9 lb/MWh gross output from fuel burning. Compliance will be based on fuel sulfur monitoring. The source has proposed a BACT emission limit of 0.00114 lb SO_2/MMBtu. SO_2 BACT is discussed in more detail in Section III.G. Turbines regulated under NSPS Subpart KKKK are not subject to NSPS Subpart GG, and HRSGs and duct burners regulated under NSPS Subpart KKKK are not subject to NSPS Subparts Da, Db, or Dc.

2. Subpart Db: The 105 MMBtu/hr auxiliary boiler (B-1) is subject to NSPS Subpart Db Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units as a steam-generating unit greater than 100 MMBtu/hr. As a natural gas-fired unit, it is exempt from the Subpart Db SO_2 standard [40 CFR 60.42b(k)(2)]. A natural gas-fired unit is not subject to a PM standard. Fuel receipts that certify the fuel meets the definition of natural gas must be kept at the facility [40 CFR 60.49b(r)] for a period of two years. The unit will be

subject to a NO_x standard and will be required to test and monitor NO_x emissions either with a CEMS or predictive monitoring developed from stack testing.

3. Subpart Dc: The 16 MMBtu/hr dew point heater (DPH-1) is subject to NSPS Subpart Dc, Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units as a steam-generating unit between 10 and 100 MMBtu/hr. Records of the amount of fuel burned in the unit each calendar month must be kept [40 CFR 60.48c(g)(2)].

4. Subpart IIII*: The emergency diesel fire water pump and diesel emergency generator are subject to NSPS Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines. The 315 bhp diesel fire water pump is subject to a NO_x + non-methane hydrocarbon (NMHC) limit of 3.0 g/hp-hr and a PM limit of 0.15 g/hp-hr, a CO limit of 2.6 g/hp-hr (Table 4 of NSPS Subpart IIII), and a requirement to use ULSD with no more than 15 ppm sulfur content (S15 ULSD). The 2500 kW diesel emergency generator is subject to a NO_x + NMHC limit of 6.4 g/kW-hr (4.8 g/hp-hr), a PM limit of 0.2 g/kW-hr (0.15 g/hp-hr), a CO limit of 3.5 g/kW-hr (2.6 g/hp-hr) (Table 1 of 40 CFR 89.112), and a requirement to use S15 ULSD.

   *DEQ has accepted delegation to enforce this federal regulation for any source subject to Title V permitting.

5. Subpart TTTT Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units: As of December 2017, DEQ has not requested delegation to enforce this regulation, but the facility will need to demonstrate compliance with the standards in this subpart. This regulation applies to stationary combustion turbines that commence construction after January 8, 2014. The standard for a natural gas-fired combustion turbine is a CO_2 emission limit of 1,000 lb/MWh of gross energy output. NSPS Subpart TTTT requires EGUs subject to the gross energy output standard to measure (Appendix D, Part 75) or calculate (Appendix G, Part 75) CO_2 mass emissions and record the hourly gross electrical output from the EGU using watt meters. EGUs that are subject to NSPS Subpart TTTT are excluded from being affected EGUs under NSPS Subpart UUUU. Virginia anticipates asking EPA to incorporate the NSPS TTTT into the Virginia SIP in the future. Until that time, Virginia is not delegated to enforce this regulation.

6. Non-applicable Subparts - The generators are not subject to NSPS Subpart JJJJ for spark ignition engines.

D. MACT Requirements:

1. Subpart ZZZZ*: The emergency diesel fire water pump (FWP-1) and emergency generator (EG-1) are subject to MACT Subpart ZZZZ National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines as new stationary RICE located at an area sources of HAP. Compliance with this MACT for these engines is met by complying with NSPS Subpart IIII (40 CFR 63.6590.c).

   *DEQ has accepted delegation to enforce this federal regulation for any source subject to Title V permitting.

   Non-applicable Subparts: MACTs have been promulgated for Combustion Turbines that are major sources of Hazardous Air Pollutants (HAPs) (Subpart YYYY National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines) and for cooling towers at major sources of HAP (Subpart Q National Emission Standards for Hazardous Air Pollutants for Industrial Process Cooling Towers). As an area HAP source, the facility will not be subject to MACT Subpart YYYY for turbines or MACT Subpart Q for cooling towers. HAP emissions from this facility will be below major levels (10 tons/yr of any individual HAP, or 25 tons/yr total HAP), so there will be no MACT requirements for the Combustion Turbines or Cooling Tower.

A MACT has been promulgated for boilers located at area sources of HAP (Subpart JJJJJJ National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources). Boilers that are gas-fired are not subject to this MACT, therefore the gas-fired auxiliary boiler (B-1) is not subject to this regulation [40 CFR 63.11195(e)].

E. Other:

1. Cross State Air Pollution Rule (CSAPR): On November 16, 2015, EPA updated the CSAPR, proposing new Federal Implementation Plans (public comment period closed on February 1, 2016). Virginia at this time will implement the CSAPR requirements through the federal implementation plan (FIP) as per Chapter 291 of the 2011 Virginia Acts of Assembly and 40 CFR 97.

2. Title IV Acid Rain Permit/Title V Federal Operating Permit: The source will also be subject to the Acid Rain and Federal Operating Permit regulations. The source will be subject to Virginia's Article 3 Federal Operating Permits for Acid Rain Sources and must submit an application no later than 24 months before the date the unit commences operation.

F. Virginia Minor New Source Review (NSR): Emissions subject to major NSR (Virginia Article 8 – PSD) are not subject to Article 6 minor NSR as per 9 VAC 5-80-1100H. The only criteria pollutants that are not subject to PSD are lead and SO_2 (See Table 3 above).

Minor NSR applicability is determined by the uncontrolled hourly emission rate x 8760 hrs/year operation, divided by 2,000 lbs/ton and compared to the values for those pollutants in 9 VAC 5-80-1105.C. Any pollutants that are subject to Minor NSR permitting must apply minor NSR BACT as per 9 VAC 5-50-260.

The sulfur content of natural gas is variable and can range from 0.1 gr/100 scf to 20 gr/100 scf. Although the permit will limit the sulfur content of the natural gas supplied to the C4GT facility to 0.4 gr/100 scf on an annual average to control H_2SO_4 and PM emissions, uncontrolled SO_2 emissions estimated at a content of just 0.5 gr/100 scf from the turbines and duct burners alone would be around 47 tons/year at 8760 hrs/year. This does not include the dew point heater, auxiliary boiler, or diesel generators which would also emit SO_2. The SO_2 exemption rate for Article 6 permitting is 40 tons/year (9 VAC 5-80-1105.C). Therefore, uncontrolled SO_2 emissions from the facility could exceed the exemption rate for that pollutant and will be subject to Minor NSR permitting and BACT requirements. Minor NSR BACT for SO_2 has been determined to be limiting the sulfur content of the natural gas to a maximum of 0.4 gr/100 scf (annual average), and limiting the sulfur content of fuel oil to a maximum of 15 ppm (0.0015 percent).

The lead content of the fuel is not so variable and no add-on controls are proposed to control lead. Total, uncontrolled lead emissions from the facility are estimated to be no more than 0.02 tons/yr. This is below the minor NSR exemption rate for lead of 0.6 tons/yr. Lead is also considered a toxic pollutant under 9 VAC 5-60-300 (see discussion under III.F.2 below) but was also found to be exempt from minor NSR permitting for toxics. Lead, therefore, is not subject to minor NSR permitting so minor NSR BACT will not apply to lead emissions from the power station.

1. Criteria Pollutants

Criteria pollutant modeling was conducted to ensure that the facility will not violate the NAAQS (see section I.A.3 above, under site suitability and attached modeling memo).

PSD increment
The PSD increment modeling showed that the concentrations for all pollutants and averaging periods were below the applicable PSD increments (see modeling memo attached).

2. Hazardous/Toxic Air Pollutants

Toxic air pollutant-emitting equipment that is subject to a MACT standard is not subject to the State Toxics Rule (9 VAC 5-60-300.C.4). Since only the emergency generators (EG-1 and FWP-1) are subject to a MACT standard, the other equipment must be evaluated for minor NSR permitting under the State Toxics Rule. Facility-wide toxic air pollutants that exceed the exemption rate in 9 VAC 5-60-300 are primarily from the duct burners. Pollutants that are not exempt from NSR permitting are acrolein and formaldehyde on an hourly and annual basis from either turbine option, and cadmium, chromium, and nickel on an annual basis for the Siemens turbine option (for which the duct burners are proposed to be twice as big as those proposed for the GE turbine option). Emission limits for these toxic air pollutants will appear in a State Only Enforceable (SOE) section of the permit. Modeling has shown that emissions of these toxic air pollutants will not exceed the Standard Ambient Air Concentration (SAAC) (see modeling memo attached). Since the formaldehyde emission factor was vendor-supplied, testing for formaldehyde will be incorporated into the permit to show compliance with that factor on which the hourly and annual emission limits were based and to demonstrate that the facility is a minor source for HAP.

G. Control Technology

PSD BACT: Sources that are subject to PSD permitting must apply a rigorous top-down BACT determination to those pollutants that triggered PSD permitting according to 9 VAC 5-50-280 (see Table 3 in Section III.B).

In determining PSD BACT, the states are given discretion in deciding whether alternative plant designs, that may be lower-emitting than those proposed by the source, are considered to be a redefinition of the source. Using renewable energy or alternative energy sources - such as solar thermal electric, photovoltaics, fuel cells, landfill gas, wind, biomass, hydroelectric, nuclear, geothermal electric, energy from waste, anaerobic digestion, tidal energy, and wave energy - reduces the use of fossil fuels and would therefore result in lower emissions than proposed for the natural-gas fired turbines and duct-fired HRSGs.

The facility, as proposed, will be a natural gas-fired, power generating plant, operating either with a higher level of baseload with limited load following capabilities (GE configuration) or with a low level of baseload with higher peaking and load following capabilities (Siemens configuration). The proposed load-following capabilities of the Siemens turbine configuration could make it more compatible with grid solar power.

Additionally, Charles City County is not a good location for wind power generation, nor is it practical for hydro power, tidal power, or wave power. Geothermal electric production is not viable in most of the eastern United States, including Virginia (www.renewableenergyworld.com – Geothermal Power and Electricity Production). And, although biofuels reduce the need for fossil fuels, the combustion of most other sources of carbon does not result in a reduction of CO_2 emissions in the short term. Nuclear power, while not emitting air pollutants, is not considered a renewable energy. It has been demonstrated in Virginia but is not within the scope of this project and would require significant design changes. Fuel cells, which generate electricity from hydrogen and oxygen using electrolytes and catalysts, do not emit air pollutants and are currently being used for powering some forms of transportation and for residential or light commercial applications, but cost, performance, and durability are some of the challenges that need to be addressed for larger demands such as those required for this project. Large-scale fuel cell power plants have not been demonstrated in practice and have only achieved tens of megawatts (https://energy.gov/eere/fuelcells/fuel-cells and http://www.powermag.com/whatever-happened-to-fuel-cells/).

C4GT has determined that the use of these alternative fuels and technologies are not available or would be considered redefining the source and are not considered BACT. DEQ concurs with this determination.

The determination of BACT usually involves a top-down method:

Step 1 – Identify all possible available control technologies;
Step 2 – Eliminate technically infeasible options;
Step 3 – Rank the technically feasible control technologies based upon emission reduction potential;
Step 4 – Evaluate ranked controls based on energy, environmental, and/or economic considerations; and
Step 5 – Select BACT.

PSD procedures require that a BACT cost feasibility analysis consider recent BACT determinations for similar facilities if the BACT technology is found to be technically feasible and does not cause significant collateral impact to energy demands or the environment. Federal guidance is clear that there can be no fixed or "bright line" cost established as representative of BACT. Rather, the cost of reducing emissions to the level of control already established within the same industry, expressed in dollars per ton reduced, is to be evaluated for reasonableness. A listing of BACT determinations from the RACT/BACT/LAER Clearinghouse (RBLC) for similar facilities is included as Appendix C in the C4GT application. The scope of the application is a natural gas-fired, combined cycle turbine with duct fired HRSGs. Option 1: The GE turbine configuration will be operated as a baseload plant with limited load following capabilities and Option 2: the Siemens turbine configuration will be operated at a lower level of baseload with higher peaking and load following capabilities. DEQ has endeavored to take into consideration the size, proposed operating scenarios (business model), brand of combustion turbines proposed by C4GT, and proposed configuration in order to develop a BACT determination that is based on the most representative data available.

1. Greenhouse gases: CO_2e emissions from the proposed C4GT facility trigger PSD permitting (on both a mass basis and CO_2e basis, see Table 3 above) so BACT must be determined. CO_2e has been a regulated pollutant since approximately 2010 so the determinations in the RBLC only go back to that time. For the purposes of finding the most recent and relevant determinations, a search of RBLC was conducted on similar power plants from 2012 forward (see Table 4 below).

    a. <u>Combustion Turbines</u>

        i. Possible Control Technologies (Step 1):

        - Carbon capture and sequestration/storage: One potential technology to control CO_2 from power plants is Carbon Capture and Sequestration/Storage (CCS). CCS consists of concentrating/capturing CO_2 from exhaust and transporting it to a location where it can be stored for a long time, usually deep in the ground. It is being demonstrated on pilot-scale power plant projects and on other types of facilities around the world.

        - Efficient power generation: Another strategy being used to minimize CO_2 emissions is to maximize the energy efficiency and performance of the turbines (i.e., minimize the amount of heat energy produced per unit of electrical output). This has been the most common BACT determination for natural gas, combined-cycle plants. By using more efficient turbines and including the steam system to capture heat from the exhaust, energy efficiency is maximized.

        - Using low carbon fuel, like natural gas instead of coal, can reduce GHG.

ii. Technical feasibility and availability of control technologies (Step 2):

CCS - Although the carbon capture technology is available and technically feasible for some applications (such as natural gas processing industries and petroleum refining), it is not a demonstrated option for a natural gas, combined cycle combustion turbine whose exhaust is characterized by high flow and low CO_2 concentration. Of the 21 large-scale CCS projects around the world that are operating or under construction, only two are power plants using post-combustion capture. Only one of those post-combustion projects is currently operating in North America, the Petra-Nova plant in Texas, and it burns pulverized coal. (http://www.globalccsinstitute.com/projects/large-scale-ccs-projects). That project was partially paid for with funding in the amount of $167 million from the Clean Coal Power Initiative (https://energy.gov/fe/petra-nova-wa-parish-project) among other funding. The C4GT power station will burn natural gas fuel.

CO_2 transport poses a problem as well. The proposed location does not appear to be geologically ideal for CCS but could offer some marginal options. Areas in southwest Virginia are more promising for this aspect of CCS but a pipeline does not currently exist. CO_2 storage in geologic formations underground must be carefully considered as there is some uncertainty as to the impact of such technology on the groundwater.

The CCS technology can cause a significant energy penalty to a power station (estimated to be up to 15%) which could cause the units to have to burn more fuel and create more air pollution than would otherwise be emitted, and/or reduced power output. CCS works best on large, coal burning units, which have the potential to emit CO_2 in larger concentrations than this plant, and that are located near sequestration areas.

Efficient power generation is technically feasible and available for this project.

Low carbon fuels are technically feasible and available for this project.

iii. Rank GHG control technologies (Step 3):

Since BACT is based on an emission limitation which reflects the maximum degree of reduction for a particular pollutant, then the best means of comparison is of emission limits rather than % control efficiency. Since energy efficiency plays a role in GHG emissions, a comparison of limits based on output (Btu/kWh or lb/MWh) rather than mass limits based on heat input (lb/MMBtu) is more beneficial. This is because, as a unit gets older and less efficient, it may still meet a lb/MMBtu limit while, at the same time, using more fuel to achieve its heat input need, therefore actually increasing short-term emissions (i.e., lb/hr). However, some facilities only include an annual CO_2e limit in the permit as BACT and do not require compliance with a heat rate limit or short term emission factor. The number of CCTs applying GHG BACT has increased markedly in the past few years (see Table 4 below).

Due to differences in size, manufacturer, configuration, cooling practice, elevation, and the method used to determine the heat rate among the permitted power plants across the country, some variability in BACT permit limit determinations is expected.

When comparing heat rate limits (expressed as Btu/kWh) or emission factors (expressed as lb CO_2e/MWh), the following bases are important to note: higher heating value (HHV) or lower heating value (LHV) of the fuel, gross power output or net power output, operation with duct firing or no duct firing, new “out of the box” efficiency or degradation over the life of the facility, full load or across all loads, corrected to ISO or not, normal operation or the inclusion of SU/SD. Additionally, the turbine model class (i.e., “G,” “H,” or “J”) can affect the size and efficiency of the turbine.

The RBLC data does not always provide this much detail. Also, the data has been found to contain inconsistent values, erroneous values, partial information, or obsolete information that has not been updated for revised permits for the same equipment. However, it does provide a starting point for further research. If the actual permit can be obtained, it may provide more accurate insight as to the parameters that are included in each GHG BACT determination. Finally, the permitting authority's Statement of Basis/Engineering Analysis and calculations, or the permit applications may also provide useful background information for comparison. Some states provide these documents online, while others do not.

No information could be found on GHG BACT limits for a natural gas combined cycle power plant using CCS for comparison with a thermal efficiency approach but estimates have shown it to be about 90% effective in reducing GHG emissions. One study[2] predicted that a natural gas-fired power plant that had a CO_2 emission rate of 803 lb/MWh could reduce emissions to 94 lb/MWh by adding CCS, but at a cost of $1,336/kW.

iv. Evaluation of Step 3 control technologies (Step 4):
As mentioned in III.G.1.a.ii above, CCS is effective, available, and technically feasible for a natural gas combustion turbine, even if it has not been demonstrated. However, construction of a carbon capture control, transport, and storage system for CO_2 gas in the Charles City County region would be cost-prohibitive. As detailed in a recent study,[3] adding CCS technology could increase a plant's construction costs up to $200 million. Similar power plants in Virginia have established that construction of a pipeline to transport the collected CO_2 to a suitable area would be $250 million alone. These factors, and the cost from a 15-20% energy penalty which increases fuel usage, would make CCS economically infeasible at this time.

The remaining technologies, namely efficient power generation and the use of low carbon fuels, are economically feasible for this facility.

v. Selection of BACT for natural-gas fired combustion turbines (Step 5):
Table 4 below lists PSD BACT determinations and BACT emission limits for GHG from recently-issued permits.

Table 4 – Comparison of GHG BACT determinations since 2012 in order of startup year - actual or anticipated

Comparison of Siemens SGT6-8000H RBLC GHG limits

Permit Year	Startup Year*	Facility	Size/Type	GHG BACT limits	Basis
2013 (EPA GHG)	2016	FPL Port Everglades, FL SGT6-8000H 250 MW turbines.	1250 MW NGCC (no duct burners) with oil backup	830 lb/MWh net NG fuel (no duct firing) (annual average) 6488 Btu/kWh net NG fuel (no duct firing) (2% op. margin + 5% degradation) (achieving 6864 Btu/kWh and 807 lb/MWh in 2016 and 6673 Btu/kWh and 785 lb/MWh through September 2017 according to www.eia.gov)	Energy efficiency

2 Rubin, Edward S and Haibo Zhai. The Cost of Carbon Capture and Storage for Natural Gas Combined Cycle Power Plants. *Environ. Sci. Technol.* 46:3076-3084 (2012)
3 Fishbeck, Paul S, David Gerard, and Sean T McCoy. Sensitivity analysis of the build decision for carbon capture and sequestration projects. *Greenhouse Gas Sci. Technol. 2:36-45* (2012)

Permit Year	Startup Year*	Facility	Size/Type	GHG BACT limits	Basis
2013	2016	Panda Liberty, PA, SGT6-8000H	829 MW NGCC	6735 Btu/kWh LHV (no duct firing, corrected to ISO conditions) (achieving 123 lb/MMBtu for six months of operation in 2016 according to https://ghg.epa.gov)	
2013	2016	Panda Patriot, PA, SGT6-8000H	829 MW NGCC	6735 Btu/kWh LHV (no duct firing, corrected to ISO conditions) (achieving 119 lb/MMBtu for six months of operation in 2016 according to https://ghg.epa.gov)	
2013	2017	Oregon Clean Energy, OH Siemens SGT-8000H	1060 MW NGCC	833 lb/MWh gross output (ISO, no duct firing) 7227 Btu/kWh HHV (full load no duct firing) (achieving 6673 Btu/kWh and 785 lb/MWh from July-November 2017 according to www.eia.gov)	High efficiency combustion technology
2014	(2018)	Panda Hummel, PA Siemens	1124 MW NGCC	281727 lb/hr w/db 298106 lb/hr w/db	
2015	(2019)	Panda Mattawoman Energy Ctr, MD Siemens SGT-8000H 1.4 optimized	990 MW NGCC	865 lb/MWh gross with or without duct firing, and includes SU/SD 6793 Btu/kWh net LHV (ISO, with duct firing)	Pipeline quality natural gas, efficient design of CT, operation based on mfg. specifications.
2016	(2019)	Rockwood Energy Center, TX Siemens SCC6-8000 H 1.4	1068 MW NGCC	965 lb/MWh HHV (includes all operations including SU/SD)	Turbine manufacturer's emission-related written instructions for maintenance activities including prescribed maintenance intervals to assure good combustion and efficient operation.
2013	(2020)	Tyr Energy Hickory Run Energy Ctr, PA Siemens SGT-8000H	1000 MW NGCC	928 lb/MWh gross	
2017	(2020)	Killingly Energy Ctr, CT SGT6-8000H	430 MW NGCC with oil backup	816 lb/MWh 7273 Btu/kWh (ISO full load, no duct firing)	Use of efficient power block, combined cycle technology, low emitting fuel

Comparison of <u>GE 7HA</u> RBLC GHG limits

Permit Year	Startup Year*	Facility	Size/Type	GHG BACT limits	Basis
2015	6/2017	Exelon Colorado Bend II Enrgy Ctr, TX GE 7HA.02	1100 MW NGCC plant	879 lb/MWh HHV gross 7395 Btu/kWh (does not include SU/SD) (achieving 7,021 Btu/kWh net and 826 lb/MWh from June to September 2017 according to www.eia.gov)	Efficient processes, practices, and designs.
2016	2017	TVA Johnsonville Cogen, TN GE 7EA GE 7HA.02 (add HRSG to Unit 20) oil backup	1100 MW	1800 lb/MWh (achieving 7,021 Btu/kWh net and 826 lb/MWh from June to September 2017 according to www.eia.gov)	Good combustion design and practices
2015	(2018)	CPV Towantic, CT GE 7HA.01	805 MW dual fuel CC plant	809 lb/MWh (net, one time initial test, corrected to ISO, CO_2) 7220 Btu/kWh full load, no DB	Not listed

Permit Year	Startup Year*	Facility	Size/Type	GHG BACT limits	Basis
2015	(2018)	Caithness Moxie Freedom, PA GE 7HA.02	1050 MW NGCC	1,000 lb/MW gross 6973 Btu/kWh HHV gross (new, clean ISO, no duct firing) 7368 Btu/kWh HHV gross (no duct firing, ISO, for lifetime of plant)	
2015	(2018)	Lackawanna Energy Ctr, PA GE 7HA.02 (air cooled)	1500 MW	1,629,115 TPY	
2015/ 17	(2019)	FGE Eagle Pines, TX GE 7HA	3450 MW	886 lb/MWh (excludes SU/SD, no duct firing) 8342 Btu/kWh (excludes SU/SD, no duct firing) 816 lb/MWh (excludes SU/SD, with duct firing) 229 tons/hr during MSS	Use of low carbon fuels, turbine design, the use of an HRSG, steam generator design, and operational energy efficiency
2016	(2019)	Rockwood Energy Ctr, TX GE 7HA.02	1068 MW	865 lb/MWh HHV (includes all operations including SU/SD)	Turbine manufacturer's emission-related written instructions for maintenance activities including prescribed maintenance intervals to assure good combustion and efficient operation.
2016	(2019)	FPL Okeechobee Clean Energy Ctr, FL GE 7HA.02	1600 MW	800 lb/MWh (new, full load, ISO) 850 lb/MWh normal operation (excludes SU/SD, fuel switching, tuning, or malfunction) 1000 lb/MWh during "non-normal" operation	Use of low-emitting fuels and technologies.
2016	(2020)	CPV Fairview Energy Ctr, PA GE 7HA.02	1050 MW NGCC	91 ppbvd @15% O2 (with or without duct firing) 847 lb/MWh gross (no duct firing)	Low sulfur fuel and GCP
2016	(2020)	Stonegate Power, Middlesex Energy, NJ GE 7HA.02	560 MW NGCC	888 lb/MWh gross (includes duct firing and some operation on ULSD)	Use of natural gas as clean burning fuel.
2015	(2020)	NRG Texas Power, Bertron, TX GE 7HA (unit 5)	700 MW NGCC or NGSC	825 lb/MWh (excluding SU/SD & maintenance not to exceed 1 hour) 7054 Btu/kWh (excluding SU/SD & maintenance not to exceed 1 hour) 179.95 tons/hr (during MSS, no duct firing)	Thermal efficiency and natural gas/GCP
2015	(2020)	NRG Cedar Bayou, TX GE 7HA (unit 5)	700 MW NGCC or NGSC	825 lb/MWh (excluding SU/SD & maintenance not to exceed 1 hour) 7054 Btu/kWh (excluding SU/SD & maintenance not to exceed 1 hour) 179.95 tons/hr (during MSS, no duct firing)	Thermal efficiency and natural gas/GCP
2017	(2020)	Archbald Energy, PA GE 7HA.02 or equivalent	485 MW NGCC	1000 lb/MW gross (excludes SU/SD)	

Other turbines operating

Permit Year	Startup Year*	Facility	Size/Type	GHG BACT limits	Basis
2010	8/2013	Calpine Russell City EC, CA (Siemens Westinghouse 501 FD Phase 2 units)	650 MW NGCC	7730 Btu/kWh (HHV net ISO w/o DB) (12.3% degradation) (achieving 7384 Btu/kWh and 869 lb/MWh in 2015, 7532 Btu/kWh and 886 lb/MWh in 2016, and 7599 Btu/kWh and 894 lb/MWh through September 2017 according to www.eia.gov)	Energy Efficiency/ GCP
2011	5/2014	PacifiCorp Lake Side 2, UT (Siemens Westinghouse)	728 MW NGCC	950 lb/MWh (gross) 6918 Btu/kW (HHV) (achieving 7185 Btu/kWh and 845 lb/MWh in 2015, 7108 Btu/kWh and 836 lbMWh in 2016, and 7478 Btu/kWh and 880 lb/MWh through September 2017 according to www.eia.gov)	Energy Efficiency/ GCP
2012	6/2014	Calpine DPEC, TX (Siemens FD3 501F), IPP CHP. upgrade existing turbine to 180 MW w/ 655 MMBtu/hr DB.	1300 MW plant Phase II, CTG6:	7730 Btu/kWh (HHV net ISO w/o DB) (12.3% degradation) 920 lb/MWh net (>90% load, no DB, ISO) (achieving 5700 Btu/kWh and 820 lb/MWh in 2015, 5705 Btu/kWh and 671 lb/MWh in 2016, and 6523 Btu/kWh and 767 lb/MWh through September 2017 according to www.eia.gov)	Energy Efficiency/ GCP
2011	8/2014	LCRA Ferguson replacement, TX (GE 7FA)	590 MW NGCC	7720 Btu/kWh (net HHV) (5% degradation) 918 lb/MWh (365-day rolling avg) (achieving 6649 Btu/kWh and 782 lb/MWh in 2015 and 6627 Btu/kWh and 780 lb/MWh in 2016 according to www.eia.gov)	Thermal Efficiency
2014	11/2014	West Deptford Energy, NJ (Phase II 3x1 Siemens) w/777 MMBtu/hr DB	750 MW NGCC	947 lb/MWh gross w/DB 7,756 Btu/kWh net HHV at ISO (achieving 6972 Btu/kWh and 820 lb/MWH in 2015 and 7064 Btu/kWh and 831 lb/MWh in 2016 according to www.eia.gov)	Turbine efficiency and use of NG as clean fuel
2013	12/2016	Dominion Brunswick, VA (Mitsubishi M501GAC) 3x1, w/ 501 MMBtu/hr DB	1400 MW NGCC	7500 Btu/kWh (net HHV) (full load corrected to ISO) 920 lb/MWh (net HHV) (achieving 7339 Btu/kWh and 863 lb/MWh from April to December 2016, and 6972 Btu/kWh and 820 lb/MWh through September 2017 according to www.eia.gov)	Thermal Efficiency

Other turbines pending or just recently commencing operation

Permit Year	Startup Year*	Facility	Size/Type	GHG BACT limits	Basis
2014	2017	CPV St. Charles, MD (GE F Class). 223.6 MW w/450 MMBtu/hr DB	725 MW NGCC	7605 Btu/kWh HHV at ISO, full load, no DB (57.4% efficiency at ISO) (achieving 7100 Btu/k/Wh from January to September 2017 according to www.eia.gov)	CO_2 CEMS
2013/ 2014	2017	Green Energy Panda Stonewall, VA (Siemens SGT6-5000F) 232 MW turbines, w/ 430 MMBtu/hr DB; 2x1	778 MW NGCC baseload or load following	903 lb/MWh gross (including SU/SD and low load) 7340 Btu/kWh HHV gross (w/o DB at ISO and full load) 7780 Btu/kWh gross (w/DB at ISO and full load) (achieving 7074.5 Btu/kWh net and 832 lb/MWh from April to September 2017 according to www.eia.gov)	Manufacturer-recommended operation and use of natural gas.

Permit Year	Startup Year*	Facility	Size/Type	GHG BACT limits	Basis
2015	2017	Interstate P&L Marshalltown, IA (Siemens SGT6-5000F or G)	600 MW (no DB)	951 lb/MWh gross over the lifetime of the plant (includes all operations including SU/SD and duct firing) (achieving 7223 Btu/kWh net from April to September 2017 according to www.eia.gov)	Not listed
2013/ 2016	Late 2017	Holland Bd of PW, MI (Siemens)	114 MW	992 lb/MWh 8361 Btu/kWh HHV net (at ISO, baseload, w/o DB, w/o transformer losses)	Energy efficiency measures and use of low carbon fuel (pipeline NG)
2014	Late 2017	ODEC Wildcat PT, MD (Mitsubishi G model)	1000 MW NGCC plant	946 lb/MWh 7500 Btu/kWh (not including SU/SD)	Exclusive use of pipeline NG and high efficiency turbine
2014	Late 2017	Footprint Pwr Salem Harbor Sta, MA (GE Energy 107F Series 5)	692 MW NGCC plant	825 lb/MWh (full load, no DB, ISO) 895 lb/MWh 365 day average	Not listed
2014	(2018)	Keys Enrgy Ctr, MD (Siemens SGT6-5000fee)	735 MW NGCC plant	869 lb/MWh gross (w or w/o DB)	"CO_2 CEMS" and two turbines cannot startup simultaneously.
2012	(2018) (ST1)	St. Joseph Enrgy Ctr, IN (Siemens)	1350 MW NGCC (in two phases)	7646 Btu/kWh HHV net (@ ISO, baseload, w/o DB or inlet cooling or transformer losses)	High thermal efficiency design
2016	(2018)	PSEG Fossil Sewaren, NJ (GE 7FA.05 or Siemens SGT6-5000G)	625 MW NGCC plant	888 lb/MWh gross w/DB, including ULSD 6,871 HHV net (@ISO, no DB, full load)	Not listed
2016	(2018)	Dominion VA – Greensville, VA (Mitsubishi)	1600 MW NGCC plant	890 lb/Mwh net output; 7212 Btu/kWh net, (full load, no DB, corrected to ISO conditions)	Use of natural gas, high efficiency design and operation, and low carbon fuel
2016	(2019)	Trinidad Gen Sta, TX (Mitsubishi 501J)	530 MW NGCC	937 lb/MWh	GCP
2016	(2019)	Southwestern Public Service Co. – Gaines Co. (four Combined Cycle SGT6-5000F5 – 426 MW per unit, 700 MMBTu/hr DB)	1706 MW NGCC (Phase 2)	960 lb/MWh (130.56 tons/hr during SU/SD)	
2014	(2019)	Moundsville Power LLC WV (GE 7FA.04)	631 MW NGCC plant	793 lb/MWh (gross, baseline, no DB) (59°F, evap. cooling on, baseload)	Low carbon fuel
2014	(2019)	Lon C Hill Power Sta, TX (Siemens SCC6-5000 or GE 7FA)	700 MW	920 lb/MWh	Not listed
2014	(2020)	CPV Pinecrest Energy Ctr, TX (GE F7FA.05, Siemens SGT6-5000F)	637-735 MW NGCC plant	<u>GE w/o DB</u> - 895 lb/MWh (7529 Btu/kWh) net or 876 lb/MW (7370 Btu/kWh) gross <u>GE w/DB</u> - 972 lb/MWh (8176 Btu/kWh) net or 942 lb/MWh (7925 Btu/kWh) gross <u>Siemens w/o DB</u> – 925 lb/MWh (7772 Btu/kWh) net or 883 lb/MWh (7424 Btu/kWh) gross <u>Siemens w/DB</u> – 967 lb/MWh (8125 Btu/kWh) net or 914 lb/MWh (7679 Btu/kWh) gross	Energy efficiency, good design and combustion practices
2012	(2020)	Cricket Valley Energy Ctr, NY	1100 MW NGCC	7605 Btu/kWh (net HHV) 950 lb/MWh	Thermal Efficiency
2013	(2020)	LaPaloma Energy Ctr, TX	735 MW	7679 Btu/kWh 942 lb/MWh	Energy efficiency, good design and combustion practices
2014	(2020)	FGE Power LLC, TX (Alstom KA24/GT24)	1620 MW NGCC	7625 Btu/kWh net output (annual test) 889 lb/MWh w/or w/o duct burning (gross, no SSM)	Energy efficiency processes, practices, and design

Permit Year	Startup Year*	Facility	Size/Type	GHG BACT limits	Basis
2016	(2020)	Decordova II Pwr, TX (GE 7FA or Siemens 5000F)	800 MW NGCC	GE 932 lb/MWh Siemens 966 lb/MWh	GCP and low carbon fuel
2016	(2022)	Eagle Mtn Steam Elec, TX (Siemens SGT6-5000F(5) or GE 7FA.05)	~500 MW NGCC	GE 932 lb/MWh Siemens 966 lb/MWh 7837 Btu/kWh gross	GCP
2013	Not built yet	Midland Cogen, MI (GE)	448 MW	995 lb/MWh w/o DB 1071 lb/MWh w/DB (6% degradation)	Thermal efficiency and clean fuels.
2012	Never built	Pioneer Valley Energy, MA (Mitsubishi M501J)	431 MW CC (oil backup)	6840 Btu/kWh 895 lb/MWh (gross)	Thermal Efficiency

** Startup dates in Table 4 were taken from the US Energy Information Administration Preliminary Monthly Electric Generator Inventory which was updated in September 2017 or company or industry websites.*

In Table 4, the most prevalent turbine models are Siemens, GE, and Mitsubishi. Turbine classes range from "F" class to "J" class, depending on model availability at the time of permitting or construction. It should be noted that, of the nearly 50 plants permitted since 2010 for GHG, only 14 were constructed and operational as of January 2018. Of those 14 plants, only one GE 7HA.02 and four Siemens SGT6-8000H had started operation. So, although there are numerous BACT determinations to compare, only a few of those limits have been demonstrated.

In general, BACT limits that are based on fuel LHV, gross power output, ISO conditions, full load, and exclusion of SU/SD, duct-burning, and degradation are lowest. Limits which are based on fuel HHV, net power output, actual operating conditions, include degradation over time, and that apply at all times (including SU/SD and duct-burning) are highest.

In the case of C4GT, DEQ determined that the best measure of efficiency of the turbine would be the heat rate (Btu/kWh) measured on a new turbine unit, using fuel HHV, at full load, corrected to ISO conditions and without duct firing, in association with a 12-month rolling emission rate determination (lb CO_2e/MWh) based on actual operation (HHV fuel heat rate divided by net power output) including duct burning, and SU/SD over the lifetime of the plant.

Table 4 BACT values for turbine heat rates range from 6,488 Btu/kWh to 8,361 Btu/kWh. The lower values are representative of Siemens SGT6-8000H turbines operating new, corrected to ISO with no DB. The lowest permitted heat rate of 6,488 Btu/kWh net (no duct burning) was for FPL Port Everglades, however, the raw data gathered from eia.gov indicates that the facility, although only operating for a couple years, may be achieving levels more like 6,864 Btu/kWh (in 2016) and 6,673 Btu/kWh (through September 2017) under actual conditions. To be comparable to the proposed heat rate for the C4GT Siemens unit, the FPL limit would have to be in terms of net, HHV at ISO without duct burning and in new condition. Other than the FPL limit, other SGT6-8000H turbines are permitted at heat rate levels higher than those proposed for C4GT Siemens turbines.

GE 7HA turbine heat rates in Table 4 range from 6,973 Btu/kWh to 8,342 Btu/kWh. C4GT is proposing a heat rate limit more stringent than the low end of this range for their GE 7HA.02 turbine option.

In addition to the heat rate limit, for ongoing compliance, the source will be required to calculate the emission rate for CO_2e, based on fuel use (HHV), and compare that to its net power output, including all operational loads and scenarios over the course of 12 months, for the lifetime of the plant. Table 4 BACT values for CO_2e emission rates range from 793 lb/MWh to 1800 lb/MWh. The lower values are representative of full load, no duct firing, and exclude SU/SD.

There is only one emission limit determination in the RBLC that is clearly based on HHV that includes all operations. That value is 865 lb/MWh for a GE 7HA.02 turbine at the Rockwood Energy Center in Texas. It is unknown if this value includes any degradation, however. This plant proposed a variety of turbine models with alternative emission limits so it is unknown if the GE 7HA.02 configuration was chosen. It is expected to commence operation in 2019 so this value has not been demonstrated. Most GHG emission limits in other PSD permits seem to be limited to full load, gross power output, and no duct firing, making comparisons to the proposed C4GT limit, which is based on actual operating conditions, difficult. Emission rates, as derived from data in the https://www.eia.gov database for six operating facilities that have GHG permit limits, range from 671 lb/MWh to 886 lb/MWh for 12 months of operation in 2016. This indicates that actual emission rates may be highly variable.

The C4GT plant will be required to show compliance with a net HHV heat rate, at full load with no duct firing, corrected to ISO conditions, of no more than 6,745 Btu/kWh for the GE turbine or 6,625 Btu/kWh for the Siemens turbine, based on an initial power block heat rate evaluation within 180 days of commencing commercial operation.

Additionally, either turbine configuration must meet an emission limit of 883 lb CO_2e/MWh net HHV on a 12-month rolling total, across all operations (including low load, duct-firing, and SU/SD). Due to the fact that this proposed emission limit applies at all times over the course of a 12-month operating period, it is possible that actual dispatch requests for the power block may include more frequent operation at low loads than was anticipated during the drafting of this permit. Although the BACT determination of efficient power generation and low carbon fuel would still apply, and the heat rate limit and the lb/MMBtu emission factors used to estimate annual emissions would not change, the emission rate limit used to represent the overall operating efficiency of the power block over the course of 12-months may need to be adjusted upward if the value of 883 lb CO_2e/MWh is found, after tracking actual fuel usage and power output, to be unachievable. Therefore, the proposed permit provides for the revision of this limit, up to a maximum of 915 lb CO_2e/MWh, if C4GT is able to demonstrate, using actual data, that the lower limit is unachievable and that the revised limit is representative of BACT for the facility, as currently proposed.

Based upon its review of the application (including amendments and supplements) and comparable BACT determinations for recently-issued GHG PSD permits, DEQ has determined that these limits are representative of BACT for the respective proposed turbine models and proposed operational configurations for each model (see Table 4 above).

b. <u>Auxiliary Boiler and Dew point heater</u>
CCS for control of the emissions of CO_2e from these smaller fuel-burning units is not technically feasible or available. BACT for these units will be the use of low carbon fuel and energy efficient design and operation. The proposed permit includes annual CO_2e limits representing the selected BACT for these emission units.

c. <u>Emergency generators and fire water pump</u>
Add-on CO_2 controls are not technically feasible for emergency generators so BACT for the fire pump will be fuel-efficient design and a limit of 500 operating hours/yr. The proposed permit includes annual CO_2e limits representing the selected BACT for these emission units.

d. Fugitive equipment leaks

Leaking piping components could contribute up to 2.5 tons of methane/year from natural gas (equivalent to 61 tons of CO_2). Control techniques consist primarily of leak detection and repair, as well as prevention of leakage. Prevention includes minimizing venting, making sure connections are secure, and performing routine maintenance on the components. Leak detection and repair includes inspecting and testing to find leaks and then repairing them. These methods are all technically feasible and available. An audible/visual/olfactory (AVO) inspection can be quite effective in detecting leaks, when performed by trained plant personnel, due to the strong smell of the mercaptan odorizers in the natural gas. A review of the RBLC indicates AVO as being the only required control for fugitive leaks from combined cycle facilities. Therefore, BACT for fugitive emissions of methane from gas piping components shall be to use best management practices (for example directed inspection and maintenance) to prevent leakage, and to perform daily AVO inspections to detect leaks and repair them.

e. Electrical Breakers

The electrical circuit breakers contain SF_6 which is a GHG. There is a small potential for these sealed units to release SF_6 from leaks. Although an alternative to the SF_6 would be to use oil or air-blast circuit breakers, which would not have the potential to release SF_6, this technology is being replaced by the sealed SF_6 circuit breakers due to the superior insulating and arc-quenching capabilities of the SF_6 type units. The oil and air-blast units are also larger than the SF_6 units, generate more noise, and the dielectric oil is flammable and also has adverse environmental impact if released. Studies have shown that the leakage rate for SF_6 from these circuit breakers is between 0.2 and 2.5 percent over the lifetime of the unit.[4] Therefore, BACT for the circuit breakers will be to minimize SF_6 leakage by using an enclosed-pressure circuit breaker with no more than a 0.5 percent annual leakage rate and a leak detection system with alarm.

2. NO_x Control

a. Combustion Turbines with duct-fired HRSG

i. Step 1 - Combustion turbines and the associated duct burners generate most of the NO_x emissions from the facility. The following control technologies were identified by C4GT as applicable to NO_x treatment for combined-cycle combustion turbines:

- Selective Catalytic Reduction (SCR)
- SCONOX™
- Selective Non-Catalytic Reduction (SNCR) and Non-Selective Catalytic Reduction (NSCR)
- Dry Low-NO_x (DLN) Combustors
- Water or Steam Injection
- XONON™, LoTOx™, THERMALLONOx™, and Pahlmann™

ii. Step 2 – The technical feasibility and availability of each technology is discussed below:

SCR

SCR is a process that involves post combustion removal of NO_x from the flue gas with a catalytic reactor. In the SCR process, ammonia injected into the turbine exhaust gas reacts with nitrogen oxides and oxygen to form nitrogen and water. SCR converts nitrogen oxides to nitrogen and water through several possible reactions that take place on the surface of a catalyst. The function of the catalyst is to

4 *SF_6 Leak Rates from High Voltage Circuit Breakers – U.S. EPA Investigates Potential Greenhouse Gas Emissions Source*, J. Blackman (U.S. EPA, Program Manager, SF6 Emission Reduction Partnership for Electric Power Systems), M. Averyt (ICF Consulting), and Z. Taylor (ICF Consulting), June 2006.

effectively lower the activation energy of the NO_x decomposition reaction. Technical factors related to this technology include increased turbine backpressure, exhaust temperature materials limitations, thermal shock/stress during rapid starts, catalyst masking/blinding, reported catalyst failure due to "crumbling", design of the NH_3 injection system, and high NH_3 slip. SCR using ammonia as a reagent represents the state-of-the art for back end gas turbine NO_x removal from base load, combined-cycle turbines. SCR is technically feasible and available

SCONOX
SCONOX™ is an emerging post-combustion technology that removes NO_x from the exhaust gas stream after formation in the combustion turbine. SCONOX™ employs a potassium carbonate bed that adsorbs NO_x where it reacts to form potassium nitrates. Periodically, a hydrogen gas stream is passed over the bed, resulting in the reaction of the potassium nitrates to re-form the potassium carbonate and the ejection of nitrogen gas and water.

SCONOX™ is reportedly capable of achieving NO_x emission reductions of 90% or more for combustion turbine application, and it is currently operating on several small natural gas-fired turbines. The most notable advantage of SCONOX™ over SCR is that it reduces NO_x without the use of ammonia. SCONOX™ thereby eliminates the possibility of "ammonia slip", or emissions of excess (unreacted) ammonia, that is present with use of SCR for NO_x control. Similar to SCR, SCONOX™ only operates within a specific temperature range.

SCONOX is no longer being offered for large combustion turbines. SCONOX™ is considerably more complex than SCR, would consume significantly more water, and would require more frequent cleaning and other maintenance. SCONOX is available but not technically feasible for a plant of this size.

SNCR/NSCR
The two other back-end catalytic reduction technologies, SNCR and NSCR, have been used to control emissions from certain other combustion process applications. However, both of these technologies have limitations that make them inappropriate for application to combustion turbines. SNCR requires a flue gas exit temperature in the range of 1,300 to 2,100 °F, with an optimum operating temperature zone between 1,600 and 1,900 °F. Simple-cycle combustion turbines have exhaust temperatures of approximately 1,100 °F, and combined-cycle turbines have exhaust temperatures much lower than simple-cycle turbines. Therefore, additional fuel combustion or a similar energy supply would be needed to create exhaust temperatures compatible with SNCR operation. This temperature restriction and related economic considerations make SNCR infeasible and inappropriate for the proposed combustion turbines. NSCR is only effective in controlling fuel-rich reciprocating engine emissions and requires the combustion gas to be nearly depleted of oxygen (<4% by volume) to operate properly. Since combustion turbines operate with high levels of excess oxygen (typically 14 to 16% O_2 in the exhaust), NSCR is infeasible and inappropriate for the proposed combustion turbines.

DLN
DLN combustion control techniques reduce NOx emissions without injecting water or steam (hence "dry"). DLN combustors are designed to control peak combustion temperature, combustion zone residence time, and combustion zone free oxygen, thereby minimizing thermal NOx formation. This is accomplished by producing a lean, pre-mixed flame that burns at a lower flame temperature and excess oxygen levels than conventional combustors.

DLN combustors have been employed successfully for natural gas-fired combustion turbines for more than fifteen years. DLN combustors are available and technically feasible.

Water/steam injection
Water or steam injection is also designed to control peak combustion temperature, combustion zone residence time, and combustion zone free oxygen, thereby minimizing thermal NO_x formation. This technology involves the injection of water or steam into the high temperature region of the flame, which minimizes thermal NO_x formation by quenching peak flame temperature.

Water and steam injection has been employed successfully for nearly thirty years, for both natural gas and oil-fired combustion turbines. Water and steam injection remains the state-of-the-art combustion technology for minimizing NO_x emissions for oil-fired combustion turbines.

Water injection is considered to be available and technically feasible for combustion turbines for natural gas and oil firing operations but would not be employed with DLN burners.

XONON™, LoTOx™, THERMALLONOx™, and Pahlmann™
A number of other combustion turbine NO_x emissions control technologies for combustion turbines are being marketed including XONON™, LoTOx™, THERMALLONOx™, and Pahlmann™. None of these technologies has reached the commercial development stage for large combustion turbines that will be fired with natural gas, and thus none are considered to be technically feasible for application to this project. DEQ concurs that these technologies are not yet commercially available technology suitable for controlling CTs of the size proposed at the C4GT site.

iii. Step 3 – Ranking of available NO_x controls
The feasible NO_x controls for a natural gas fired turbine are water/steam injection with standard combustor design, water/steam injection with advanced combustor design, DLN combustor design and SCR. The most effective technologies that are available for a large natural gas-fired, combined cycle power generating facility for controlling NO_x are dry low NO_x combustion to minimize NO_x formation and post-combustion treatment with SCR.

iv. Step 4 – Evaluation of Step 3 controls
All technically-feasible NOx controls proposed in Step 3 above are economically feasible and do not contribute significantly to loss of energy or increased environmental impacts.

v. Step 5 - BACT Determination: SCR and DLN Combustors
C4GT has proposed a combination of the remaining identified control options for NO_x: DLN combustion and SCR. The proposed combustion turbines use local flame temperature optimization in the combustion zone and an improved combustion nozzle to produce a more homogeneous air-fuel mixture resulting in uncontrolled NO_x emissions of 9 ppmvd or less at 15% O_2 when firing natural gas, the fuel proposed for use by C4GT. The draft permit proposes the additional use of SCR to control NO_x emissions from the CTs to the following level (at 15% O_2):

- 2.0 ppmvd with or without duct burning

Compliance with the limits is to be based on a one-hour block average.

From 2012 to 2017, over 30 projects were permitted at 2.0 ppmvd at 15% O_2. The proposed limits for the C4GT facility are as stringent as any listed in EPA's RACT/BACT/LAER Clearinghouse (RBLC) for electric generating facilities.

b. Auxiliary boiler and dew point heater

i. List of control technologies
- Front end NO_x reduction technologies (low excess air, low NO_x burners, internal flu gas recirculation) are very commonly used and represent BACT for most sources.
- SCR (approximately 82% efficient) with outlet temps around 700-750°F

ii. Technical feasibility and availability of NO_x Control
- Front end NOx reduction technologies, as well as SCR, are available. However, SCR would not be maximized at the temperatures proposed for the boiler or dew point heater (<300°F) and bypassing the economizer to achieve lower NOx emissions would cause decreased efficiency and therefore require additional fuel to be burned to meet heating demands of the boiler. This would increase emissions of other pollutants. So SCR is not a technically feasible NOx reduction strategy for the auxiliary boiler or for the dew point heater.

iii. Ranking of technologies
- Low NO_x burners are the best front end technology for reducing NO_x emissions to 0.011 lb/MMBtu.

iv. Evaluation of Step 3 controls
C4GT is proposing the use of front-end NOx reduction technologies so no cost analysis is required. These technologies are efficient and do not create energy loss or adverse environmental impact.

v. BACT determination
- A review of the RBLC shows recently-permitted natural gas-fired boilers and fuel gas heaters/dew point heater have NO_x BACT limits between 0.01 and 0.013 lb/MMBtu (9 ppmvd).
- DEQ concurs that low NO_x burners are BACT for both the auxiliary boiler and dew point heater to achieve a level of 0.011 lb/MMBtu.

c. Emergency Generators/Fire water pump
i. List of control technologies (Step 1)
- SCR is used to control NO_x on larger non-emergency generators.
- The use of ULSD fuel, good combustion practices and limited hours of operation can control NOx emissions from ICE.

ii. Technical feasibility and availability of NO_x Control (Step 2)
Although add-on controls such as SCR are used to control NO_x on larger non-emergency generators, if necessary to meet national standards for emissions, no add-on controls have been demonstrated in practice for emergency internal combustion engines firing ULSD fuel. The proposed emissions from the emergency units at this facility can meet these standards without add-on controls. The use of ULSD fuel, good combustion practices and limited hours of operation are available and technically feasible.

iii. Ranking of technologies (Step 3)
The use of ULSD fuel, good combustion practices can result in NO_x+NMHC emissions of 4.8 g/bhp-hr for the emergency generator and 3.0 g/bhp-hr for the firewater pump engine. Limited hours of operation limit annual NOx emissions.

iv. Evaluation of Step 3 controls (Step 4)
C4GT is proposing the use of good combustion practices and limited hours of operation to control NOx so no cost analysis is required. These technologies are efficient and do not create energy loss or adverse environmental impact.

v. BACT determination (Step 5)
The RBLC shows very little variability in BACT determinations for diesel-fired emergency engines. The facility proposes NOx BACT for the 2500 kW diesel emergency generator (EG-1) and 315 hp diesel fire water pump (FWP-1) to be GCP. The manufacturers of EG-1 certify the unit to meet the 4.8 g/bhp-hr NOx+ NMHC and the FWP-1 is certified to meet the a NO_x+NMHC limit of 3.0 g/bhp-hr. This is consistent with the RBLC.

3. Carbon Monoxide Control - CO emissions are formed in the exhaust of a combustion turbine as a result of incomplete combustion of the fuel. 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. Generally the effect of the combustion zone temperature and residence time on CO emissions generation is the exact opposite of their effect on NO_x emissions generation. Higher combustion zone temperatures and residence times lead to more complete combustion and lower CO emissions, but higher NO_x emissions.

a. <u>Combustion Turbines</u>

i. Possible Control Technologies (Step 1)
- Oxidation Catalyst
- Good Combustion Practices

ii. Available and feasible (Step 2)
An oxidation catalyst (OxCat) is a post-combustion technology that removes CO from the exhaust gas stream after formation in the combustion turbine. In the presence of a catalyst, CO will react with oxygen present in the exhaust stream, converting it to carbon dioxide (CO_2). No supplementary reactant is used in conjunction with an oxidation catalyst. The oxidation of CO to CO_2 utilizes the excess air present in the turbine exhaust, and the activation energy required for the reaction to proceed is lowered in the presence of the catalyst. 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 particulate matter and sulfuric acid mist.

CO catalytic oxidation reactors operate in a relatively narrow temperature range. Optimum operating temperatures for these systems generally fall into the range of 700 °F to 1100 °F. At lower temperatures, CO conversion efficiency falls off rapidly. Above 1200 °F, catalyst sintering may occur, thus causing permanent damage to the catalyst. For this reason, the CO catalyst is strategically placed within the proper turbine exhaust lateral distribution (it is important to evenly distribute gas flow across the catalyst) and proper operating temperature at base load design conditions. Operation at partial load, or during startup/shutdown will result in less than optimum temperatures and reduced control efficiency.

Typical pressure losses across an oxidation catalyst reactor (including pressure loss due to ammonium salt formation) are in the range of 0.7 to 1.0 inches of water. Pressure drops in this range correspond roughly to a 0.15 percent loss in power output and fuel efficiency.

Catalyst systems are subject to loss of activity over time. Since the catalyst itself is the most costly part of the installation, the cost of catalyst replacement should be considered on an annualized basis. Catalyst life may vary from the manufacturer's typical 3-year guarantee to a 5- to 6-year predicted life. Periodic testing of catalyst material is necessary to predict annual catalyst life for a given installation.

Oxidation catalysts have been employed successfully for two decades on natural gas combustion turbines. An oxidation catalyst is considered to be technically feasible for application to this project.

GCP, consisting primarily of controlled fuel/air mixing and adequate temperature and gas residence time, are used to minimize the formation of CO. GCP are technically feasible for this project.

iii. Ranking of technologies for CO control (Step 3)
The most effective technologies that are available for a large natural gas-fired, combined cycle power generating facility for controlling CO are GCP to control the formation of CO, and OxCat as a post-combustion treatment.

iv. Evaluation of Step 3 controls (Step 4)
C4GT has proposed the top-ranked option (a combination of control options for CO: OxCat and GCP) as BACT so a cost analysis is not necessary. These controls, when properly utilized, are efficient and do not create energy loss or adverse environmental impact.

v. BACT determination (Step 5)
Performance of an oxidation catalyst can be affected by temperature, load, catalyst type, surface area, gas concentration, residence time, and other factors.

Minimization of NO_x emissions can affect CO emissions because as NO_x emissions get lower, CO emissions could potentially creep higher. This is especially important with the new 1-hour NO_x NAAQS which is very stringent. In order to maintain the NO_x limitations, CO could be more variable.

The lowest CO limits using GCP and OxCat in the most recent BACT determinations in the RBLC or in permits reviewed for this permit action are presented in Table 5 below.

Table 5 – RBLC data for CO emissions from Natural Gas fired Combustion Turbines

	Turbine & permit date	Limit w/o DB	Limit w/DB	Description
Kleen Energy Systems, CT	SGT6-5000F February 2008	0.9 ppmvd	1.7 ppmvd	At full load, excluding SU/SD, maintenance
CPV Towantic Energy Center, CT	GE 7HA.01 November 2015	0.9 ppmvd	1.7 ppmvd	At full load excluding SU/SD, maintenance
West Deptford Energy Center, NJ	SGT6-5000F (Phase II) July 2014	0.9 ppmvd	1.5 ppmvd	At full load excluding SU/SD, maintenance
Dominion Greensville Power Sta, VA	M501J June 2016	1.0 ppmvd	1.6 ppmvd	Across all loads excluding SU/SD, maintenance

Of these facilities, only the Kleen Energy Systems plant is operating. This facility tested their turbines in 2011 and showed compliance with this limit at full load with no duct burning. It should also be noted that, for the Kleen Energy facility, the VOC BACT limit is 5.0 ppm, which is the highest VOC limit in the RBLC for recently issued permits for a natural gas-fired combustion turbine. This may indicate a catalyst that is highly selective for CO control, or that the VOC control efficiency for the OxCat was assumed to be minimal, or the vendor-definition for “VOC” may differ from other vendors.

The Dominion Greensville limit is across all loads and excludes SU/SD, but this is a “J” class turbine and would have a different emission profile than the “H” class turbines proposed for C4GT. This facility is still under construction so the limits have not been demonstrated.

Other than these facilities, CO limits in recently-issued permits for similar facilities are greater than or equal to 2.0 ppmvd with or without duct burning.

The proposed CO limits for the C4GT turbines are as follows:

Turbine	Limit w/o DB	Limit w/DB	Description
Option 1 GE 7HA.02	1.0 ppmvd	1.6 ppmvd	Applies across all loads. Excludes SU/SD and maintenance.
Option 2 SGT6-8000H	1.8 ppmvd	1.8 ppmvd	

Compliance with the limits is to be based on a three-hour rolling average. This is different than some other permits issued a few years ago that call for a one-hour average for CO. Due to the very stringent CO limit proposed for C4GT (similar to the Dominion Greensville permit), DEQ allowed for a longer averaging time to account for the possibility of CO emission variability that could occur.

DEQ concludes that the proposed oxidation catalyst control, along with GCP, constitute BACT for CO (3-hour rolling average) from the CTs.

b. Auxiliary Boiler and Dew Point Heater

i. List of control technologies (Step 1)
- GCP
- OxCat

ii. Technical feasibility and availability of CO Control (Step 2)
- GCP are feasible and available for these units
- OxCat is technically feasible and available for the auxiliary boiler but, due to the small size of the dew point heater (16 MMBtu), OxCat is not technically feasible for that unit.

iii. Ranking of technologies (Step 3)
- OxCat in combination with GCP could reduce emissions to about 0.006 lb/MMBtu.
- GCP alone can result in emissions from the units of 0.037 lb/MMBtu.

iv. Evaluation of controls in Step 3 (Step 4)
- Good combustion practices does not result in energy, environmental, or economic impacts.
- OxCat has been shown to increase emissions of PM and H_2SO_4.

v. BACT determination (Step 5)
- RBLC shows two facilities that installed OxCat on auxiliary boilers:

Table 6

	Size	
Footprint Power Salem, MA (State BACT) under construction	80 MMBtu/hr	0.0035 lb/MMBtu except during SU/SD; 4.7 ppmvd@ 3% O_2 except during SU/SD
IPL Marshalltown, IA started operation April 2017	52 MMBtu/hr	0.0164 lb/MMBtu including SU/SD; Modeled at 2.7 lbs/hr (0.045 lb/MMBtu)

Of these, the Footprint Salem plant has not started operation so the limit (which is State BACT) has not been demonstrated. The Marshalltown facility (IPL) has started up but it is unknown if the boiler has been tested for CO. A 52 MMBtu/hr boiler was installed, rather than the 60.1 MMBtu that was originally proposed (BACT did not change). IPL voluntarily applied to put OxCat on the boiler so their cost-analysis was not based on a BACT determination or a top-down BACT Step 4 cost-effectiveness evaluation. The facility was modeled at 0.041 lb/MMBtu for NAAQS compliance.

RBLC also indicated that CPV St. Charles, MD which started up in March 2017, had an auxiliary boiler permitted at 0.018 lb CO/MMBtu (1.74 lb/hr) using GCP. The boiler was originally proposed as a 93 MMBtu/hr unit, however a 28.3 MMBtu/hr boiler was installed instead. The emission limit was not changed but a limit of 1.74 lb/hr for a 28.3 MMBtu/hr boiler comes to 0.06 lb/MMBtu. It is unknown if this boiler has been stack tested for compliance with this limit. CPV St. Charles claimed CO control from FGR and ULNB because those technologies supported effective combustion (“collateral control”). The fuel gas heater at CPV St. Charles (9.5 MMBtu/hr) was limited to 0.08 lb CO/MMBtu using GCP, which is quite a bit higher than that proposed for C4GT’s dew point heater.

Dominion Greensville, VA proposed a BACT limit of 0.037 lb/MMBtu (equivalent to 6.8 lb/hr) for their 185 MMBtu/hr boiler, using GCP, but was permitted at 0.035 lb/MMBtu (6.6 lb/hr). This boiler is almost twice the size of the boiler proposed for C4GT (at 3.9 lb/hr) and a reduction to 0.035 lb/MMBtu would reduce annual emissions from the C4GT unit by only 0.9 ton/yr. Dominion Greensville is not yet operating so this BACT limit has not been demonstrated.

Several facilities have been permitted at 0.036 lb/MMBtu for CO but those units are mostly small (<50 MMBtu/hr). Both CPV Fairview and CPV Towantic, in Connecticut, received BACT permit limits for 92.4 MMBtu/hr natural gas-fired auxiliary boilers of 0.037 lb/MMBtu using GCP (OxCat was found economically infeasible at $7,400/ton of CO removed). The 100 MMBtu/hr boiler at Moundsville Power, WV has a BACT limit of 0.04 lb/MMBtu using GCP. The 99 MMBtu/hr boiler at Oregon Clean Energy, OH has a BACT limit of 0.055 lb/MMBtu using GCP.

- Oxidation catalyst used in conjunction with GCP could reduce CO emissions from the C4GT auxiliary boiler by 14.2 tons/yr at a cost of $7,455 per ton, and, for the dew point heater, reduce CO emissions by 2.1 tons/yr at over $50,000 per ton, making OxCat economically infeasible for either unit.

- C4GT proposed a rate of 0.037 lb/MMBtu based on vendor-supplied factors. DEQ has determined that GCP is BACT for CO to a level of 0.037 lb/MMBtu for the auxiliary boiler (B-1) and dew point heater (DPH-1).

c. Emergency Generator and Fire Water Pump
The control of CO from the emergency units can be achieved without the use of add-on CO controls which can be problematic on emergency RICE units. Proper operation and maintenance of the unit, and burning of clean fuel, can achieve CO levels that represent

BACT and are also comparable to BACT limitations for similar units found in the RBLC. BACT for CO from the emergency units will be the use of clean fuel and the proper operation and maintenance of the units to keep CO emissions at 2.6 g/hp-hr for the diesel emergency unit (EG-1) and for the fire-water pump (FWP-1).

4. Sulfuric acid mist – primarily formed from the combustion of sulfur-containing fuels, with a small contribution of H_2SO_4 from the SCR and Oxidation catalyst controls.

   a. Combustion Turbines
   The use of low-sulfur fuels is the only feasible and available technology to reduce H_2SO_4 emissions from a natural gas combustion turbine. Flue gas desulfurization is only feasible on plants that produce much larger quantities of H_2SO_4 and would produce a significant pressure drop that would require an induced draft fan, potentially causing air/fuel mixing problems. The lowest-sulfur fuel is natural gas which is what is proposed at this facility. The sulfur content of the natural gas is dependent on the location from which the gas is piped. The sulfur content of the natural gas available in Charles City County can achieve 0.4 gr/100 dscf on an annual average (levels across the country can range from 0.1 gr to 2.0 gr/100 dscf) and cannot be controlled by C4GT. DEQ concurs with the proposed use of pipeline quality natural gas to achieve the following BACT rates for the combustion turbines:

   Option 1 – GE turbines
   - 2.5 lb/hr for H_2SO_4 without duct burning
   - 2.7 lb/hr for H_2SO_4 with duct burning

   Option 2 – Siemens turbines
   - 2.2 lb/hr for H_2SO_4 without duct burning
   - 2.7 lb/hr for H_2SO_4 with duct burning

   b. Auxiliary boiler and dew point heater
   The only feasible control for H_2SO_4 from the auxiliary boiler and dew point heater is the use of low-sulfur fuel, i.e., pipeline quality natural gas. This control is determined to be BACT for the auxiliary boiler and dew point heater. The facility will test the sulfur content of the natural gas on a monthly basis.

   c. Emergency generators
   The use of ultra low sulfur diesel (ULSD or S15) in the diesel-fired generators (EG-1 and FWP-1) at 500 hrs/yr is considered BACT for H_2SO_4 from the emergency units. The facility will obtain fuel supplier certifications and track annual hours of operation for these units.

5. VOC - Formation of VOC emissions are attributable to the same factors as described for CO emissions above. VOC emissions are a result of incomplete combustion of carbonaceous fuels, and this is influenced primarily by the temperature and residence time within the combustion zone.

   a. Combustion Turbines

      i. List of possible VOC controls for combustion turbines (Step 1)
         - Oxidation catalyst
         - Good combustion practices

      ii. Available and Feasible technologies (Step 2)
      An oxidation catalyst is a post-combustion technology that removes VOC from the exhaust gas stream after formation in the combustion turbine. In the presence of a catalyst, VOC will react with oxygen present in the exhaust stream, converting it to

carbon dioxide and water vapor. The performance of an oxidation catalyst is affected by the VOCs that are actually emitted. No supplementary reactant is used in conjunction with an oxidation catalyst. An oxidation catalyst is considered to be available and technically feasible for application to this project.

GCP consisting primarily of controlled fuel/air mixing and adequate temperature and gas residence time are used to minimize the formation of VOCs. This option is available and technically feasible.

iii. Ranking of technologies for VOC control (Step 3)
The most effective technologies that are available for a large, natural gas-fired, combined cycle power generating facility for controlling VOC are GCP to control the formation of VOC, and oxidation catalyst as a post-combustion treatment.

iv. Evaluation of Step 3 technologies (Step 4)
GCP and oxidation catalyst are economically feasible and do not impact energy use. A slight increase in H_2SO_4 emissions may occur with OxCat, but that does not offset the VOC control efficiency since H_2SO_4 emissions are minimized by the use of low-sulfur fuel.

v. BACT (Step 5)
VOC emission rates for recently permitted (2012 to present) combined-cycle facilities are in the range of 0.7 ppmvd at 15% O_2 to 4.0 ppmvd at 15% O_2 as shown in C4GT's summary of EPA's RBLC. The emission limits at the low end are typically without duct burning and the higher end of the range reflect the higher emissions associated with duct burning. C4GT's proposed VOC limits include all operational loads and excludes SU/SD.

Table 7
VOC BACT for GE turbines w/o DB

Facility	Model	BACT Limit	Comments
Footprint Salem, MA	GE7FA.05	1.0 ppmvd	State BACT; 1-hr avg; Excludes SU/SD
Moundsville, WV	GE7FA.04	1.0 ppmvd	
FPL Okeechobee, FL	GE7HA.02	1.0 ppmvd	Loads >90%
NRG Bertron, TX	GE7FA	1.0 ppmvd; 4.4 lb/hr	
CPV Towantic	GE7HA.01	1.0 ppmvd	
Lon C Hill, TX	GE7FA	2.0 ppmvd	
La Paloma, TX	GE7FA.04	2.0 ppmvd	Normal operations
Sand Hill Energy, TX	GE7FA	2.0 ppmvd; 6.7 lb/hr	1-hr avg

VOC BACT for GE turbines w/DB

Facility	Model	BACT Limit	Comments
NRG Bertron, TX	GE7FA	1.0 ppmvd; 4.4 lb/hr	Basis for this limit is unknown.
Footprint Salem, MA	GE7FA.05	1.7 ppmvd	State BACT; 1-hr avg; Excludes SU/SD
Moundsville, WV	GE7FA.04	2.0 ppmvd; 5.3 lb/hr	
CPV Towantic	GE7HA.01	2.0 ppmvd	
Lon C Hill, TX	GE7FA	2.0 ppmvd	
La Paloma, TX	GE7FA.04	2.0 ppmvd	3-hr avg; Normal operations
Sand Hill Energy, TX	GE7FA	2.0 ppmvd	1-hr avg

VOC BACT for Siemens turbines w/o DB

Facility	Model	BACT Limit	Comments
Killingly Energy Ctr, CT	SGT6-8000H	0.7 ppmvd; 2.8 lb/hr	Steady state; full load
Green Energy Partners, VA	SGT6-5000F5	1.0 ppmvd; 3.0 lb/hr	Loads >50%
Oregon Clean Energy, OH	SGT-8000H	1.0 ppmvd; 3.9 lb/hr	Steady state; full load
IPL Marshalltown, IA	SGT6-5000F	1.0 ppm	
St. Joseph Energy Ctr, IN	SGT6-5000F	1.0 ppmvd	Excludes SU/SD
NRG Bertron, TX	SF5	1.0 ppmvd; 4.9 lb/hr	Excludes SU/SD
Keys Energy Ctr, MD	SGT6-5000F	1.0 ppmvd	Excludes SU/SD
La Paloma, TX	SGT6-5000F.5	2.0 ppmvd	3-hour avg; Normal operations
LS Renaissance, MI	501FD2	2.0 ppmvd	

VOC BACT for Siemens turbines w/DB

Facility	Model	BACT Limit	Comments
Green Energy Partners, VA	SGT6-5000F5	1.5 ppmvd; 5.4 lb/hr	Loads >50%
Killingly Energy, CT	SGT6-8000H	1.6 ppmvd; 8.3 lb/hr	Steady state; full load
Oregon Clean Energy, OH	SGT-8000H	1.9 ppmvd; 5.9 lb/hr	Steady state; full load
St. Joseph Energy Ctr, IN	SGT6-5000F	2.0 ppmvd	Excludes SU/SD
Keys Energy Ctr, MD	SGT6-5000F	2.0 ppmvd	Excludes SU/SD
LS Renaissance, MI	501FD2	2.0 ppmvd	
La Paloma, TX	SGT6-5000F.5	2.0 ppmvd	3-hour avg; Normal operations

Not on the lists above:

- the Chouteau Power Plant in Oklahoma is represented in their 2009 permit as having a VOC limit of 0.3 ppm (no DB) in the RBLC (and a correspondingly high CO limit of 8 ppmv). However, this facility is not subject to a 0.3 ppm limit for VOC; the permit contains a limit of 5.27 lb/hr. As no compliance determination for the ppm value is required, the Chouteau facility is not comparable.
- Also, Mitsubishi turbines (“G” class and “J” class) were proposed at the Dominion Brunswick and Greensville Power Plants, VA, as baseload facilities. They were permitted at 0.7 ppmvd without duct burner firing using OxCat and GCP. The Greensville plant has not been started up yet. The results of a stack test at the Brunswick facility in April 2017 showed the facility was meeting these limits.
- The Green Energy Partners (Panda Stonewall) facility, VA proposed OxCat and GCP as BACT for a Siemens SGT6-5000F5 (“F” class) turbine at a level of 1.0 ppmvd w/o DB and 1.5 ppmvd w/DB. This facility was permitted for a 430 MMBtu/hr DB for each turbine, whereas the C4GT facility is requesting a 991 MMBtu/hr DB for each Siemens turbine (SGT6-8000H), therefore emissions during DB firing could be expected to be higher for the C4GT facility. The BACT emission limits for Panda Stonewall are for operation between 50-100% load and would compare with the operation of the GE turbines at C4GT, not the Siemens configuration. Stack testing in April 2017 showed the Stonewall plant was meeting these permit limits.

The applicant has proposed to control VOC using GCP and an oxidation catalyst for the combustion turbines. The oxidation catalyst is proposed for the dual purpose of controlling CO emissions and VOC emissions. The applicant proposed VOC (as CH_4) limits, based on some control by an oxidation catalyst at 15% O_2 (calculated as a three-hour average and including all operational loads, excluding SU/SD). The GE and Siemens turbines have separate emission limits to reflect the operational configurations mentioned in I.C.1.a:

Option 1 – GE turbines
• 0.7 ppmvd without duct burner firing

• 1.4 ppmvd with duct burner firing

Option 2 – Siemens turbines
• 1.0 ppmvd without duct burner firing
• 2.0 ppmvd with duct burner firing

DEQ concurs that the use of GCP and an oxidation catalyst represent BACT for VOC control for the proposed C4GT combustion turbine models and their operational configurations.

b. <u>Auxiliary boiler and dew point heater</u>

i. List of control technologies (Step 1)
- Good combustion practices
- Clean burning fuels
- Oxidation catalyst

ii. Technical feasibility and availability of VOC Control (Step 2)
- Good combustion practices are feasible and available.
- Oxidation catalyst is feasible and available for an auxiliary boiler but is not feasible on a small dew point heater such as that proposed for this plant.

iii. Ranking of technologies (Step 3)
- Oxidation catalyst used in conjunction with GCP would achieve the best VOC control rate for the auxiliary boiler.
- GCP and the use of natural gas as a fuel can result in emissions of VOC from both units of 0.005 lb/MMBtu.

iv. Evaluation of Step 3 technologies (Step 4)
Although OxCat would result in lower emissions of VOC from the auxiliary boiler, the technology is only marginally effective for this pollutant (<40%). The cost to reduce VOC by 40% would result in a cost of over $100,000/ton removed. OxCat is not economically feasible to remove VOC from an auxiliary boiler of the size proposed by C4GT.

GCP and the use of natural gas as fuel is economically feasible and would not contribute to energy loss or collateral environmental degradation.

v. BACT determination (Step 5)
The RBLC shows that only a couple facilities have BACT VOC limits below 0.005 lb/MMBtu using GCP on an auxiliary boiler (some lower determinations were LAER). The auxiliary boiler at the Black Hills Cheyenne Prairie Generating Station, WY was permitted at 0.0017 lb/MMBtu. This boiler, however, is only 25 MMBtu/hr, less than a quarter of the size of the boiler at C4GT. Therefore, this unit is not comparable. This boiler was scheduled to commence operation in June 2017 but it is unknown whether the unit has been stack tested and is in compliance with this limit.

Another RBLC entry is for a 182 MMBtu/hr auxiliary boiler at Indeck Niles Generating Station, MI with VOC limited to 0.004 lb/MMBtu using GCP. This unit was permitted in January 2017 and is not operating yet, so compliance is not verified.

There are no dew point heater BACT limits lower than 0.005 lb VOC/MMBtu in the RBLC.

GCP results in VOC emissions that are consistent with BACT at similar facilities at 0.005 lb/MMBtu. DEQ concurs with C4GT that GCP are BACT for VOC from the auxiliary boiler and dew point heater.

c. Emergency generator and fire water pump
The use of GCP and limiting operation to 500 hrs/yr are considered BACT for VOC from the emergency units. The manufacturer of EG-1 certifies the unit meets the 4.8 g/bhp-hr NMHC+NOx limit for Tier II engines. And the FWP-1 is certified to meet the NO_x+NMHC limit of 3.0 g/bhp-hr proposed as BACT. These values are consistent with BACT determinations for similar units in the RBLC.

d. Fuel Tank
Uncontrolled VOC emissions from the diesel fuel tanks are estimated to be only 2.5 lbs/yr total so no limits will be placed in the permit.

6. Particulate Matter Controls (PM filterable only, and PM_{10} and $PM_{2.5}$, including condensable) – PM emissions consist of filterable particulate matter and PM_{10} and $PM_{2.5}$ emissions are a combination of filterable (front-half) and condensable (back-half) particulate. Filterable particulate matter is formed from impurities contained in the fuels and from incomplete combustion. Condensable particulate emissions, which contribute to PM_{10} and $PM_{2.5}$ but not PM, are attributable primarily to the formation of sulfates and possibly organic compounds. PM, PM_{10} and $PM_{2.5}$ are all subject to PSD permitting.

Both a lb/MMBtu and a lb/hour limit are included in the permit for compliance with PM_{10} and $PM_{2.5}$ limits for the combustion turbines. A BACT limit is represented in lb/MMBtu units and the limit showing compliance with NAAQS modeling is in lb/hr units. Each limit can represent a different worst-case operating Case and the difference in configuration of the GE and Siemens turbines also affect PM emissions.

a. Combustion Turbines

i. List of PM control technologies (Step 1)
- Low ash/low sulfur fuel
- Add-on controls such as ESP, scrubbers or baghouses
- Proper combustion controls

ii. Available and technically feasible technologies (Step 2)
The use of low-ash fuels, like natural gas, propane, and ultra low sulfur diesel (ULSD or S15) fuel are readily available and technically feasible to use in combined cycle turbines.

Add-on PM controls (such as ESPs, scrubbers or baghouses) are not recommended for combustion turbines burning natural gas because the PM particles are quite small (<1 micron) and the air volume is quite large, thus diluting the concentration of PM in the exhaust. Add-on controls are not available nor technically feasible for a combustion turbine.

The use of low-ash fuel (natural gas) and GCP are widely accepted as PSD BACT for PM, PM_{10} and $PM_{2.5}$ from combustion.

iii. Ranking of PM, PM_{10} and $PM_{2.5}$ control technologies (Step 3)
The most stringent particulate control method demonstrated for gas turbines is the use of low ash and low sulfur fuel with GCP. No add-on control technologies are listed in EPA's RBLC. Proper combustion control and the firing of fuels with negligible or zero ash content and a low sulfur content for the combustion turbines is the only control method listed.

iv. Evaluation of Step 3 technologies (Step 4)
The use of clean-burning, low-sulfur fuels is economically feasible and does not contribute to energy loss or increased environmental impact.

v. BACT for PM, PM_{10} and $PM_{2.5}$ (Step 5)

A search of the RBLC shows high variability for particulate matter. Some permitting agencies assume PM, PM_{10} and $PM_{2.5}$ emissions from natural gas combustion turbines to be identical; some assume all PM is $PM_{2.5}$ and only permit that; some do not permit PM (filterable) as a separate pollutant. Some limits include SU/SD, some do not. Some have both a lb/MMBtu limit and a lb/hr limit, and some only a lb/hr limit. Most have separate limits for turbines without DB and with DB but some have only one or the other. In some cases the PM_{10} limit for the CT+DB values are highest on a lb/MMBtu basis, but for some facilities, emissions are higher without duct burning. And some facilities have limits on the sulfur content of the fuel (which can contribute to PM emissions) and others do not. The use of SCR and oxidation catalyst to control other air pollutants can contribute to PM_{10} and $PM_{2.5}$ emissions.

Turbine data provided to C4GT from the respective turbine vendors showed that the highest lb/MMBtu emission rate for PM, PM_{10} and $PM_{2.5}$ from the combustion turbines occurred at low load (30-40%), but the highest lb/hr emission rate occurred at the highest loads (90-100%). The highest emissions for duct firing on both a lb/MMBtu and lb/hr basis occurred during the highest duct burner firing rate for the duct burner associated with the Siemens turbine. That duct burner is very large (991 MMBtu/hr). For the GE turbine and duct burner (475 MMBtu/hr), the highest PM, PM_{10} and $PM_{2.5}$ lb/hr and lb/MMBtu emission rates occurred either at peak duct firing or at peak CT operation with minimal duct firing.

The proposed PM, PM_{10} and $PM_{2.5}$ BACT limits for the C4GT turbines include operation <u>at all loads and include SU/SD</u>. Many of the permit limits in other permits are based on other modes of operation (i.e., full load, excluding SU/SD). Additionally, the natural gas to be combusted in the C4GT turbines is limited to 0.4 gr/100 scf, whereas some other plants are permitted anywhere from 0.1 gr to 1.0 gr/100 scf, which would affect PM, PM_{10} and $PM_{2.5}$ emissions.

Table 8 lists permitted PM, PM_{10} and $PM_{2.5}$ values for natural gas-fired combustion turbines in terms of lb/MMBtu and/or lb/hr. It is assumed that the lb/hr limits represent the worst case emissions at full load for each turbine; however that value is dependent on the heat input of the CT, which is not consistent among the various permitted turbines.

In order to compensate for the size of the turbine (or turbine + DB) the RBLC **PM_{10} lb/hr limits** were divided by the MMBtu/hr heat input values at full load, yielding a lb/MMBtu value that can be compared for all the facilities. **PM_{10}** values were chosen because PM and/or $PM_{2.5}$ values were not consistently permitted. <u>These calculated values are not permit limits, nor BACT limits, but rather only used for comparison.</u>

Of the 29 facilities listed in Table 8 that were permitted since 2012, only seven have started up (i.e., Dominion Brunswick, Green Energy Partners Stonewall, Panda Liberty, Panda Patriot, Oregon Clean Energy, the West Deptford Station, and CPV St. Charles).

Table 8 – Comparison of **PM_{10}** values at full load with no DB, from low to high

Facility	Turbine & size	Pollutant	Permit Limit(s)	lb/hr calculated value	BACT
Keys Energy Ctr, MD (10/31/14) Planned startup 2018	SGT6-5000Fee CT only 4,917 MMBtu/hr	PM_{filt} PM_{10}, $PM_{2.5}$	8.8 lb/hr 0.0019 lb/MMBtu 11.0 lb/hr 0.0025 lb/MMBtu	11 lb/hr ÷ 4917 MMBtu/hr = 0.0022 lb/MMBtu	Limit applies at all times. Pipeline quality NG, GCP (sulfur content of NG 0.2 gr/100 dscf)
	CT & DB 5,317 MMBtu/hr	PM_{filt} PM_{10}, $PM_{2.5}$	12.2 lb/hr 0.0023 lb/MMBtu 15.0 lb/hr 0.0028 lb/MMBtu	15 lb/hr ÷ 5317 MMBtu/hr = 0.0028 lb/MMBtu	
Dominion Greensville, VA (6/17/16) Planned startup 2018	M501J CT only 3,227 MMBtu/hr	PM_{10}, $PM_{2.5}$	9.2 lb/hr 0.0030 lb/MMBtu	9.2 lb/hr ÷ 3227 MMBtu/hr = 0.0029 lb/MMBtu	Pipeline quality NG, GCP, low sulfur/low carbon fuel (0.4 gr/100 dscf)
	CT & DB 3,727 MMBtu/hr	PM_{10}, $PM_{2.5}$	14.1 lb/hr 0.0039 lb/MMBtu	14.1 lb/hr ÷ 3727 MMBtu/hr = 0.0038 lb/MMBtu	
Dominion Brunswick, VA (3/12/13) Started up April 2016	M501GAC CT only 2,941 MMBtu/hr	PM_{10} & $PM_{2.5}$	9.7 lb/hr 0.0033 lb/MMBtu	9.7 lb/hr ÷ 2941 MMBtu/hr = 0.0033 lb/MMBtu	GCP & low sulfur/low carbon fuel (0.4 gr/100 dscf)
	CT & DB 3,442 MMBtu/hr	PM_{10} & $PM_{2.5}$	16.3 lb/hr 0.0047 lb/MMBtu	16.3 lb/hr ÷ 3442 MMBtu/hr = 0.0047 lb/MMBtu	
Tenaska Westmoreland, PA (2/12/16) Planned startup 2018	M501J CT only 3,147 MMBtu/hr CT & DB 3,547 MMBtu/hr	PM_{tot}, PM_{10}, $PM_{2.5}$	11.8 lb/hr 0.0039 lb/MMBtu w/DB	CT + DB 11.8 lb/hr ÷ 3547 MMBtu/hr = 0.0033 lb/MMBtu	Excludes SU/SD. GCP & low sulfur/low ash fuel (sulfur content of NG 0.25 gr/100 dscf average)
Stonegate Middlesex Energy, NJ (7/19/16) Planned startup 2020	GE 7HA.02 CT only 3,462 MMBtu/hr	PM_{filt} PM_{10}&$PM_{2.5}$	4.4 lb/hr 11.7 lb/hr	11.7 lb/hr ÷ 3462 MMBtu/hr = 0.0034 lb/MMBtu	NG, clean fuel (sulfur content of 0.47 gr/100 scf)
	CT & DB 4,061 MMBtu/hr	PM_{filt} PM_{10}&$PM_{2.5}$	10.4 lb/hr 18.3 lb/hr	18.3 lb/hr ÷ 4061 MMBtu/hr = 0.0045 lb/MMBtu	
Moxie Freedom, PA (9/1/15) Planned startup 2018	GE7HA.02 3,327 MMBtu/hr	PM_{filt}, PM_{10}, $PM_{2.5}$	11.7 lb/hr w/o DB 0.0063 lb/MMBtu w/ or w/o DB)	11.7 lb/hr ÷ 3327 MMBtu/hr = 0.0035 lb/MMBtu	Low sulfur fuel & GCP. Limits apply during <u>normal operation</u>. (sulfur content of NG 0.4 gr/100 dscf monthly avg)
	CT & DB 3,527 MMBtu/hr	PM_{filt}, PM_{10}, $PM_{2.5}$	13.9 lb/hr w/DB 0.0063 lb/MMBtu w/ or w/o DB)	13.9 lb/hr ÷ 3527 MMBtu/hr = 0.0039 lb/MMBtu	
Moundsville, WV (11/21/14) Planned startup 2019	GE 7FA.04 CT only 2,087 MMBtu/hr CT & DB 2,159 MMBtu/hr	All PM is assumed to be $PM_{2.5}$	7.6 lb/hr w/ or w/o DB	CT 7.6 lb/hr ÷ 2087 MMBtu/hr = 0.0036 lb/MMBtu CT + DB 7.6 lb/hr ÷ 2159 MMBtu/hr = 0.0035 lb/MMBtu	Excludes SU/SD. GCP, inlet air filters, NG (sulfur content of NG 0.2 gr/100 dscf)
Footprint Salem Harbor, MA (1/30/14) Currently in commissioning phase	GE107.F.5 CT only 2,300 MMBtu/hr	PM, PM_{10}, $PM_{2.5}$	8.8 lb/hr 0.0071 lb/MMBtu (1-hr avg)	8.8 lb/hr ÷ 2300 MMBtu/hr = 0.0038 lb/MMBtu	GCP, At loads above 75%, excludes SU/SD (sulfur content of NG 0.5 gr/100 dscf)
	CT & DB 2,449 MMBtu/hr	PM, PM_{10}, $PM_{2.5}$	13.0 lb/hr 0.0062 lb/MMBtu (1-hr avg)	13 lb/hr ÷ 2449 MMBtu/hr = 0.0053 lb/MMBtu	
CPV Towantic, CT (11/30/15) Planned startup 2018	GE7HA.01 CT only 2,511 MMBtu/hr	$PM_{2.5}$	9.73 lb/hr 0.0065 lb/MMBtu	9.73 lb/hr ÷ 2511 MMBtu/hr = 0.0039 lb/MMBtu	GCP, NG At full load/steady state (sulfur content of NG 0.5 gr/100 dscf)
	CT & DB 3,506 MMBtu/hr	$PM_{2.5}$	20.4 lb/hr 0.0081 lb/MMBtu	20.4 lb/hr ÷ 3506 MMBtu/hr = 0.0058 lb/MMBtu	
Moxie Patriot, PA (1/31/13) Started up 2016	SGT6-8000H CT 3,007 MMBtu/hr CT & DB 3,171 MMBtu/hr	PM_{tot}, PM_{10}, $PM_{2.5}$	12.2 lb/hr 0.0057 lb/MMBtu	12.2 lb/hr ÷ 3007 MMBtu/hr = 0.0041 lb/MMBtu	Low ash/low sulfur fuels; 0.4 gr/100 scf sulfur. Excludes SU/SD.

Facility	Turbine & size	Pollutant	Permit Limit(s)	lb/hr calculated value	BACT
DTE Renaissance Pwr, MI (11/1/13) Never executed	CT only 2,143 MMBtu/hr	PM $_{filt}$, PM_{10}, $PM_{2.5}$	9 lb/hr (PM_{10},$PM_{2.5}$) 0.0042 lb/MMBtu	9.0 lb/hr ÷ 2143 MMBtu/hr = 0.0042 lb/MMBtu	GCP
	CT & DB 2,807 MMBtu/hr	PM $_{filt}$, PM_{10}, $PM_{2.5}$	15.6 lb/hr (PM_{10},$PM_{2.5}$) 0.0073 lb/MMBtu	15.6 lb/hr ÷ 2807 MMBtu/hr = 0.0056 lb/MMBtu	GCP
PSEG Fossil Sewaren, NJ (3/7/14 & 3/10/16) Planned startup 2018	GE7HA.02 Unit 7 CT only 3,311 MMBtu/hr	PM $_{filt}$ PM_{10}	4.7 lb/hr 14.4 lb/hr	14.4 lb/hr ÷ 3311 MMBtu/hr = 0.0043 lb/MMBtu	NG, clean fuel (sulfur content of NG 0.75 gr/100 dscf). Excludes SU/SD.
	CT & DB 4,013 MMBtu/hr	PM filt PM_{10}	12.0 lb/hr 22.6 lb/hr	22.6 lb/hr ÷ 4013 MMBtu/hr = 0.0056 lb/MMBtu	
Green Energy Partners Stonewall, VA (4/30/13, 7/15/14) Started up December 2016.	SGT6-5000F5 CT only 2,314 MMBtu/hr	PM_{10} & $PM_{2.5}$	10.1 lb/hr 0.00374 lb/MMBtu at full load	10.1 lb/hr ÷ 2314 MMBtu/hr = 0.0044 lb/MMBtu	GCP and pipeline quality NG (0.1 gr/100 dscf max), 3-hr average. Excludes SU/SD.
	CT & DB 2,711 MMBtu/hr	PM_{10} & $PM_{2.5}$	14.5 lb/hr	14.5 lb/hr ÷ 2711 MMBtu/hr = 0.0054 lb/MMBtu	
Killingly Energy Ctr, CT (6/30/17) Not constructed yet (application submitted to switch to M501JAC turbine)	SGT6-8000H CT only 2,969 MMBtu/hr	PM_{10}, $PM_{2.5}$	13.0 lb/hr 0.0044 lb/MMBtu	13 lb/hr ÷ 2969 MMBtu/hr = 0.0044 lb/MMBtu	Steady state operation (sulfur content of natural gas 0.0016% by weight). GCP
	CT & DB 3,915 MMBtu/hr	PM_{10}, $PM_{2.5}$	19.5 lb/hr 0.0050 lb/MMBtu	19.5 lb/hr ÷ 3915 MMBtu/hr = 0.0050 lb/MMBtu	
West Deptford, NJ Phase II expansion (7/18/14) Startup November 2014	Siemens or GE F class CT only 2,276 MMBtu/hr	PM $_{filt}$ PM_{10}&$PM_{2.5}$	6.0 lb/hr 10 lb/hr	10 lb/hr ÷ 2276 MMBtu/hr = 0.0044 lb/MMBtu	NG as fuel
	CT & DB 3,053 MMBtu/hr	PM $_{filt}$ PM_{10}&$PM_{2.5}$	15.1 lb/hr 0.0048 lb/MMBtu 21.55 lb/hr 0.0069 lb/MMBtu	21.55 lb/hr ÷ 3053 MMBtu/hr = 0.0071 lb/MMBtu	NG as fuel
Oregon Clean Energy, OH (6/18/13) Started up summer of 2017	SGT-8000H CT only 2,932 MMBtu/hr	PM_{10}&$PM_{2.5}$	13.3 lb/hr 0.0047 lb/MMBtu	13.3 lb/hr ÷ 2932 MMBtu/hr = 0.0045 lb/MMBtu	Steady state/full load ISO. NG & Clean fuel (sulfur content of NG 0.5 gr/100 dscf)
	CT & DB 3,232 MMBtu/hr	PM_{10}&$PM_{2.5}$	14.0 lb/hr 0.0055 lb/MMBtu	14 lb/hr ÷ 3232 MMBtu/hr = 0.0043 lb/MMBtu	
Lackawanna Energy Ctr, PA (12/23/15 & 7/12/16) Planned startup 2018	GE7HA.02 CT only 3,304 MMBtu/hr CT & DB 3,951 MMBtu/hr	PM $_{filt}$	CT + DB 9.0 lbs/hr 0.003 lb/MMBtu		NG, inlet air filters, DLN (excludes SU/SD) (sulfur content of NG 0.4 gr/100 dscf)
		PM_{10}, $PM_{2.5}$	CT + DB 18.0 lbs/hr 0.0059 lb/MMBtu	18 lb/hr ÷ 3951 MMBtu/hr = 0.0046 lb/MMBtu	
Indeck Niles, MI (1/4/17) Not constructed yet	H and J class CT & DB 4,161 MMBtu/hr	PM $_{filt}$	9.9 lb/hr 0.002 lb/MMBtu		NG, GCP, inlet air conditioning
		PM_{10}&$PM_{2.5}$	19.8 lb/hr 0.0050 lb/MMBtu	19.8 lb/hr ÷ 4161 MMBtu/hr = 0.0048 lb/MMBtu	Includes SU/SD. NG, GCP, inlet air conditioning
St. Charles Pwr, LA (8/31/16) Planned startup 2020	M501GAC CT & DB 3,663 MMBtu/hr	PM_{10}, $PM_{2.5}$	17.52 lb/hr 0.008 lb/MMBtu w/ or w/o DB	17.52 lb/hr ÷ 3663 MMBtu/hr = 0.0048 lb/MMBtu	Normal operation. GCP and NG fuel
CPV St. Charles, MD (4/23/14 & 1/1/17) Startup Feb 2017	GE7FA.05 2,308 MMBtu/hr	PM_{10}	11.3 lb/hr 0.006 lb/MMBtu	11.3 lb/hr ÷ 2308 MMBtu/hr = 0.0049 lb/MMBtu	Pipeline quality NG (0.25 gr S/100scf) & GCP
	CT & DB 2,710 MMBtu/hr	PM_{10}	15.7 lb/hr 0.0070 lb/MMBtu	15.7 b/hr ÷ 2710 MMBtu/hr = 0.0058 lb/MMBtu	
Panda (Moxie) Liberty, PA (10/10/12, 7/9/13) Started up summer 2016	SGT6-8000H CT 2,890 MMBtu/hr CT & DB 3,277 MMBtu/hr	PM_{tot}, PM_{10}, $PM_{2.5}$	0.0040 lb/MMBtu for 468 MW plant 0.0057 lb/MMBtu for 454 MW plant	0.0057 lb/MMBtu	Low ash/low sulfur fuels; 0.4 gr/100 scf sulfur

Facility	Turbine & size	Pollutant	Permit Limit(s)	lb/hr calculated value	BACT
Mattawoman Energy Ctr, MD 990 MW (11/13/15) Planned startup 2020	SGT6-8000H 1.4 optimized 2,988 MMBtu/hr	PM_{filt} PM_{10},$PM_{2.5}$	8.9 lb/hr 0.004 lb/MMBtu 17.9 lb/hr 0.0079 lb/MMBtu	17.9 lb/hr ÷ 2988 MMBtu/hr = 0.0060 lb/MMBtu	Limits apply at all times. Pipeline quality NG, GCP (max short term sulfur content 1.0 gr/100 dscf; annual average 0.25 gr/100 dscf). Testing done at >90% load with DB.
	CT & DB 3,636 MMBtu/hr	PM_{filt} PM_{10},$PM_{2.5}$	13.9 lb/hr 0.0039 lb/MMBtu 27.7 lb/hr 0.0078 lb/MMBtu	27.7 lb/hr ÷ 3636 MMBtu/hr = 0.0076 lb/MMBtu	
Future Power Good Spring, PA (3/4/14) Not constructed	Siemens 5000 CT & DB 2,401 MMBtu/hr	PM PM_{10}	10.4 lb/hr 15.6 lb/hr	15.6 lb/hr ÷ 2401 MMBtu/hr = 0.0065 lb/MMBtu	?
St. Joseph En Ctr, IN (12/3/12) PhaseI Planned startup 2018	SGT6-5000F 2,300 MMBtu/hr CT only	PM, PM_{10}, $PM_{2.5}$	15 lb/hr 0.0092 lb/MMBtu	15 lb/hr ÷ 2300 MMBtu/hr = 0.0065 lb/MMBtu	GCP & fuel specification
	CT & DB	PM, PM_{10}, $PM_{2.5}$	18 lb/hr 0.0078 lb/MMBtu	0.0078 lb/MMBtu	
Thetford Gen Sta, MI (7/25/13) Permit rescinded 8/1/2016.	CT & DB 2,587 MMBtu/hr or 2,688 MMBtu/hr	PM_{filt} PM_{10}, $PM_{2.5}$	0.0033 lb/MMBtu 0.0066 lb/MMBtu	0.0066 lb/MMBtu	Limits apply at all times. Combustion air filters; efficient combustion control; low sulfur natural gas fuel.
York (2) Energy Ctr, PA (6/15/15 & 8/1/16) Planned startup 2018	GE 7F.05 CT only 2,513 MMBtu/hr	PM, PM_{10}, $PM_{2.5}$	0.0068 lb/MMBtu	0.0068 lb/MMBtu	GCP & low sulfur fuel
	CT & DB 3,333 MMBtu/hr	PM, PM_{10}, $PM_{2.5}$	0.0066 lb/MMBtu	0.0066 lb/MMBtu	
CPV Fairview, PA (9/2/16) Not constructed yet	GE7HA.02 CT only 3,338 MMBtu/hr	PM tot, PM_{10}, $PM_{2.5}$	0.0068 lb/MMBtu	0.0068 lb/MMBtu	Low sulfur fuel, GCP
	CT & DB 3,763 MMBtu/hr	PM tot, PM_{10}, $PM_{2.5}$	0.0050 lb/MMBtu	0.0050 lb/MMBtu	
WFEC Mooreland Gen Sta, OK (adding additional turbine)(7/2/13) Not built	GE 7FA.05 or SGT6-5000F5 CT only 2,480 MMBtu/hr	PM, PM_{10}, $PM_{2.5}$	22.2 lb/hr	22.2 lb/hr ÷ 2480 MMBtu/hr = 0.0090 lb/MMBtu	GCP & low ash fuel (> 50% load, normal operation, excludes SU/SD)
	CT & 820.5 MMBtu/hr DB 3,300 MMBtu/hr	PM, PM_{10}, $PM_{2.5}$	31.8 lb/hr	31.8 lb/hr ÷ 3300 MMBtu/hr = 0.0096 lb/MMBtu	
Midland Cogen Venture, MI (448 MW expansion) (4/23/13) Never executed	CT only 1,950 MMBtu/hr	PM tot PM_{10} & $PM_{2.5}$	0.006 lb/MMBtu (PM) 23.4 lb/hr 0.012 lb/MMBtu	23.4 lb/hr ÷ 1950 MMBtu/hr = 0.012 lb/MMBtu	CT limits includes SU/SD. GCP (add-on controls economically infeasible
	CT & DB 2,486 MMBtu/hr	PM tot PM_{10} & $PM_{2.5}$	0.004 lb/MMBtu (PM) 19.9 lb/hr 0.0080 lb/MMBtu	19.9 lb/hr ÷ 2486 MMBtu/hr = 0.008 lb/MMBtu	CT & DB excludes SU/SD? GCP (add-on controls economically infeasible

It should be noted that “PM” values in Table 8 sometimes included condensable PM and sometimes only filterable PM, however that distinction was not always clearly stated in the RBLC or the issued permits.

When the facilities in Table 8 are sorted by the *calculated* **PM_{10}** lb/MMBtu values, it can be seen that the GE7FA and GE7HA turbines are clustered around 0.0034-0.0039 lb/MMBtu unless they are permitted for a sulfur content less than 0.4 gr/100 scf or greater than 0.5 gr/100 scf.

And the SGT6 turbines in Table 8 are clustered in the 0.0041-0.0048 lb PM_{10}/MMBtu range.

Dominion Greensville, Dominion Brunswick, Tenaska Westmoreland, and St. Charles (Louisiana) permits propose Mitsubishi G and J class turbines, which have different emission profiles than the H class turbines proposed for C4GT.

Other facilities did not propose a lb/hr limit and the permitted lb/MMBtu basis (load) was not stated, therefore accurate comparisons with those facilities could not be made (Panda Liberty, York, and CPV Fairview).

C4GT proposes the use of GCP and the use of NG with an average annual sulfur content of 0.4 gr/100 scf for the combustion turbines and duct burners at the following BACT rates for PM, PM_{10} and $PM_{2.5}$ (which apply at all times, including low load, SU/SD, tuning, and water washing):

Facility	Turbine & size	Pollutant	Permit Limit(s)	lb/hr calculated value	BACT
C4GT, VA	GE 7HA.02 CT only 3,482 MMBtu/hr	PM PM_{10} & $PM_{2.5}$	0.0046 lb/MMBtu 12.2 lb/hr 0.0069 lb/MMBtu	12.2 lb/hr ÷ 3482 MMBtu/hr = 0.0035 lb/MMBtu	GCP and the use of pipeline-quality natural gas with a maximum sulfur content of 0.4 grains per 100 scf, on a 12-month rolling average.
	CT & DB 3,957 MMBtu/hr	PM PM_{10} & $PM_{2.5}$	0.0038 lb/MMBtu 17.3 lb/hr 0.0049 lb/MMBtu	17.3 lb/hr ÷ 3957 MMBtu/hr = 0.0044 lb/MMBtu	
	SGT6-8000H CT only 3,116 MMBtu/hr	PM PM_{10} & $PM_{2.5}$	0.0049 lb/MMBtu 13.7 lb/hr 0.0065 lb/MMBtu	13.76 lb/hr ÷ 3116 MMBtu/hr = 0.0044 lb/MMBtu	
	CT & DB 4,107 MMBtu/hr	PM PM_{10} & $PM_{2.5}$	0.0056 lb/MMBtu 24.2 lb/hr 0.0065 lb/MMBtu	24.2 lb/hr ÷ 4107 MMBtu/hr = 0.0059 lb/MMBtu	

In order to demonstrate compliance with the NAAQS for PM_{10} and $PM_{2.5}$, worst case PM_{10} and $PM_{2.5}$ lb/hr permit limits are included in the permit. For the Siemens turbines without duct firing, the PM_{10} and $PM_{2.5}$ limits (13.7 lb/hr) were estimated at 100% load, @10°F, and 7% relative humidity. With duct firing, the limits for the Siemens turbine (24.2 lb/hr) were based on 100% load and 100% duct firing, @95°F, and 76% relative humidity. For the GE turbines without duct firing, the limits (12.2 lb/hr) were estimated at 100% load, @10°F, and 44.2% relative humidity. With duct firing, the limits for the GE turbine (17.3 lb/hr) were based on 100% load and 100% duct firing, @95°F, and 42% relative humidity. All limits were based on 14.6 psia atmospheric pressure.

Worst case PM_{10} and $PM_{2.5}$ lb/MMBtu permit limits are included for BACT demonstration (by stack testing). The PM_{10} and $PM_{2.5}$ limits for the Siemens turbine without duct firing (0.0065 lb/MMBtu) were estimated at 41% load, @100°F, and 77% relative humidity. The limits for the Siemens turbine with duct firing (0.0065 lb/MMBtu) are based on 100% load and 100% duct firing, @95°F, and 76% humidity. The limits for the GE turbine without duct firing (0.0069 lb/MMBtu) were estimated at 30% load, @59°F, and 60% relative humidity. The GE limits with duct firing (0.0049 lb/MMBtu) were based on 100% turbine load and 10% duct firing, @10°F, and 44% relative humidity. All limits were based on 14.6 psia atmospheric pressure.

Filterable PM limits are included for BACT demonstration only (no NAAQS for PM) and so only a lb/MMBtu limit is included in the permit. The PM limit for the Siemens turbine without duct firing is 0.0049 lb/MMBtu, the limit for the Siemens turbine with duct firing is 0.0056 lb/MMBtu, the limit for the GE turbine without duct firing is 0.0046 lb/MMBtu, and the limit for the GE turbine with duct firing is 0.0038 lb/MMBtu.

DEQ has determined that these limits represent BACT for the respective turbines and operational configurations of each turbine option.

b. Auxiliary Boiler and Dew Point Heater

Particulate matter emissions from the boiler and dew point heater are a combination of filterable and condensable particulate. GCP and limiting fuel use to only pipeline quality natural gas are proposed by the applicant as BACT for PM_{filt}, PM_{10} and $PM_{2.5}$ emissions from the auxiliary boiler and dew point heater. This is supported by the RBLC BACT determinations for similar units (see Table 9 and Table 10). DEQ agrees that this constitutes BACT for particulate emissions from the boiler and heater.

Table 9 – RBLC PM determinations for similar boilers (50-150 MMBtu/hr) from lowest to highest on a lb/MMBtu basis for PM_{10} or $PM_{2.5}$ (values in parentheses are estimated based on lb/hr limit and heat rating of unit in MMBtu/hr).

Facility	Equipment	Pollutant	Limit	BACT
Moundsville, WV 11/21/14	Aux boiler 100 MMBtu/hr	$PM_{2.5}$	0.005 lb/MMBtu 0.5 lb/hr	GCP & pipeline NG
Salem Harbor, MA 1/30/14	Aux Boiler 80 MMBtuhr	PM_{10}, $PM_{2.5}$	0.005 lb/MMBtu 0.4 lb/hr	Excludes SU/SD
Hess Newark, NJ 9/13/12 (effective 11/27/12)	Aux boiler 66.2 MMBtu/hr	PM_{10}	0.33 lb/hr (0.005 lb/MMBtu)	NG as fuel
PSEG Fossil Sewaren, NJ 3/7/14; 3/10/16	Aux boiler 80 MMBtu/hr	PM_{filt}, PM_{10}, $PM_{2.5}$	0.26 lb/hr (0.0033 lb/MMBtu) 0.4 lb/hr (0.005 lb/MMBtu)	NG as fuel
Stonegate Middlesex Energy, NJ 7/19/16	Aux boiler 97.5 MMBtu/hr	PM_{filt}, PM_{10}, $PM_{2.5}$	0.181 lb/hr (0.0018 lb/MMBtu) 0.488 lb/hr (0.005 lb/MMBtu)	NG as fuel
York Energy, PA 6/15/15	Aux boiler 61 MMBtu/hr	PM_{tot}, PM_{10}, $PM_{2.5}$	0.005 lb/MMBtu	GCP & low S fuel
CPV Fairview, PA 9/2/16	Aux boiler 92.4 MMBtu/hr	PM_{tot}, PM_{10}, $PM_{2.5}$	0.007 lb/MMBtu 1.29 lb/hr	Not stated
Lackawanna, PA 12/23/15; 7/12/16	Aux boiler 184.8 MMBtu/hr	PM_{filt}, PM_{10}, $PM_{2.5}$	0.002 lb/MMBtu 0.007 lb/MMBtu	NG fuel
Moxie Freedom, PA 9/1/15	Aux boiler 55.4 MMBtu/hr	PM_{tot}, PM_{10}, $PM_{2.5}$	0.007 lb/MMBtu	Not stated
Holland, MI 2/5/16	Aux boiler 83.5 MMBtu/hr	PM_{filt}, PM_{10}, $PM_{2.5}$	0.0018 lb/MMBtu 0.007 lb/MMBtu	GCP
Thetford, MI 7/25/13	Aux boiler 100 MMBtu/hr	PM_{filt}, PM_{10}, $PM_{2.5}$	0.0018 lb/MMBtu 0.007 lb/MMBtu	Efficient combustion, NG fuel
Cricket Valley, NY 2/3/16	Aux boiler 60 MMBtu/hr	PM_{filt}	0.005 lb/MMBtu	GCP and pipeline NG
Indeck Niles, MI 1/4/17	Aux Boiler 182 MMBtu/hr	PM_{filt} PM_{10}, $PM_{2.5}$	0.005 lb/MMBtu 1.36 lb/hr (0.0075 lb/MMBtu)	GCP
St. Joseph, IN 12/3/12	Aux boiler 80 MMBtu/hr	PM, PM_{10} $PM_{2.5}$	0.0075 lb/MMBtu 0.6 lb/hr	GCP and fuel specs
Pinecrest Energy Ctr, TX 11/12/13	Aux boiler 150 MMBtu/hr	$PM_{2.5}$	1.14 lb/hr (0.0076 lb/MMBtu)	GCP & pipeline NG
Keys Energy, MD 10/31/14	Aux boiler 93 MMBtu/hr	PM_{filt}, PM_{10}	0.0075 lb/MMBtu	Efficient design, pipeline NG, GCP
Oregon Clean Energy, OH 6/18/13	Aux boiler 99 MMBtu/hr	PM_{tot}	0.79 lb/hr (0.008 lb/MMBtu)	NG fuel
Marshalltown, IA 11/19/15	Aux boiler 52 MMBtu/hr	PM_{tot}	0.008 lb/MMBtu	Not stated

Table 10 – RBLC PM determinations for dew point/fuel gas heaters

Facility	Equipment	Pollutant	Limit	BACT
Moxie Freedom, PA 9/1/15	FGH 14.6 MMBtu/hr	PM_{tot}, PM_{10}, $PM_{2.5}$	0.007 lb/MMBtu	Not stated
Lackawanna, PA 12/23/15; 7/12/16	FGH 12 MMBtu/hr	PM_{filt}, PM_{10}, $PM_{2.5}$	0.002 lb/MMBtu 0.007 lb/MMBtu	NG fuel
Thetford, MI 7/25/13	FGH 12.0 MMBtu/hr	PM_{filt}, PM_{10}, $PM_{2.5}$	0.0018 lb/MMBtu 0.007 lb/MMBtu	Efficient combustion, NG fuel

Facility	Equipment	Pollutant	Limit	BACT
Dominion Greensville, VA 6/17/16	FGH 7.8 MMBtu/hr	PM_{10}, $PM_{2.5}$	0.007 lb/MMBtu	GCP & pipeline NG (0.4 gr/100 scf S)
	FGH 16.1 MMBtu/hr	PM_{10}, $PM_{2.5}$	0.007 lb/MMBtu	GCP & pipeline NG (0.4 gr/100 scf S)
Dominion Brunswick, VA 5/13/15	FGH 8 MMBtu/hr	PM_{10}, $PM_{2.5}$	0.007 lb/MMBtu	GCP & pipeline NG (0.4 gr/100 scf S)
CPV St. Charles, MD 4/23/14	FGH 9.5 MMBtu/hr	PM_{filt}, PM_{10}	7.6 lb/MMcf 0.07 lb/hr (0.0074 lb/MMBtu)	GCP & pipeline NG
Indeck Niles, MI 1/4/17	DPH 27 MMBtu/hr	PM_{filt}, PM_{10}, $PM_{2.5}$	0.002 lb/MMBtu 0.2 lb/hr (0.0074 lb/MMBtu)	GCP
Wildcat Pt, MD 4/8/14	DPH 5 MMBtu/hr	PM_{filt}, PM_{10}, $PM_{2.5}$	0.0075 lb/MMBtu	GCP & pipeline NG
Mattawoman, MD 11/13/15	FGH 13.8 MMBtu/hr	PM_{filt}, PM_{10}, $PM_{2.5}$	0.0019 lb/MMBtu 0.0075 lb/MMBtu	GCP & pipeline NG
Holland, MI 2/5/16	Fuel preheater 3.7 MMBtu/hr	PM_{filt}, PM_{10}, $PM_{2.5}$	0.007 lb/MMBtu 0.0075 lb/MMBtu	GCP
Marshalltown, IA 11/19/15	DPH 13.32 MMBtu/hr	PM_{tot}	0.008 lb/MMBTu	Not stated

Data in the RBLC for similar boilers and dew point heater/fuel gas heaters (see Table 9 and Table 10) show PM limits ranging from 0.005 lb/MMBtu to 0.008 lb/MMBtu. The reduction in emissions for a 105 MMBtu/hr boiler from 0.007 lb/MMBtu to 0.005 lb/MMBtu would result in a reduction of only 0.25 lb/hr and 0.9 tons/year. Short-term PM_{filt}, PM_{10} and $PM_{2.5}$ emissions from the auxiliary boiler and the dew point heater will be limited to 0.007 lbs/MMBtu.

c. <u>Fire pump and emergency generator</u>
Possible PM controls for an emergency generator consist of the following: catalysts, including diesel particulate filters, clean fuels and GCP. Of these, catalysts are not used for units that are only run on an as-needed basis, making them not technically feasible for this unit. Therefore, PSD BACT for PM, PM_{10} and $PM_{2.5}$ from the emergency generator units shall be the use of clean fuels (i.e., ULSD) and GCP to achieve the following emission limits:

Unit	BACT Limit		
	PM	PM_{10}	$PM_{2.5}$
EG-1	0.15 g/hp-hr	0.15 g/hp-hr	0.15 g/hp-hr
FWP-1	0.15 g/hp-hr	0.15 g/hp-hr	0.15 g/hp-hr

d. <u>Cooling Towers</u>
Cooling towers produce drift, which is composed of fine water droplets that may contain dissolved solids and thus contribute to PM_{filt}, PM_{10} and $PM_{2.5}$ emissions. The only feasible particulate matter controls for cooling towers is to use water with low total dissolved solids content and drift eliminators. The facility will use clean cooling water with drift eliminators.

7. Startup/shutdown – BACT applies during startup and shutdown (SU/SD) of the turbines. During SU/SD, some post-combustion controls are not working at the optimum level of control, however, during these periods, the turbines and duct burners are also not operating at their highest output and other emissions may be reduced for that reason. C4GT uses automated systems to control combustion in the turbines. These systems are designed to operate in the most efficient manner, which, in turn, minimizes emissions. GCP including controlling the fuel/air mixing, temperature, and gas residence time during combustion to minimize emissions. C4GT submitted BACT for SU/SD for the turbines as follows (alternative limits for SU/SD, as applicable, can be found in the BACT Summary Table 11):

a. GHG – No alternate BACT was proposed since the BACT limitations include SU/SD.

b. NOx - Technically feasible NOx controls during SU/SD include SCR, DLN, and GCP. Of these, SCR is most effective, followed by GCP and DLN. A combination of these controls will be employed to minimize NOx during SU/SD.

c. CO - Technically feasible CO controls during SU/SD include oxidation catalyst, DLN (which can result in lowering CO as well as NOx), and GCP. Of these, oxidation catalyst is most effective, followed by GCP and DLN. A combination of these controls will be employed to minimize CO during SU/SD.

d. SO_2 – No alternate BACT was proposed since the combustion of low sulfur fuel will remain BACT during SU/SD.

e. VOC - Although VOC controls would be similar to CO controls, the effectiveness of these controls could be minimal during SU/SD. C4GT proposes limitations on the duration of SU/SD events to minimize VOC emissions during SU/SD. Compliance with CO emission limits (verified by stack testing and CEMS) will constitute compliance with VOC limits since both VOC and CO are minimized in similar ways during SU/SD.

f. PM, PM_{10} and $PM_{2.5}$ - Add-on controls for PM, PM_{10}, and $PM_{2.5}$ like electrostatic precipitators or baghouses are usually not applied to natural gas plants, especially for alternative operating scenarios such as SU/SD. So, the only feasible control for PM, PM_{10}, and $PM_{2.5}$ would be the use of clean fuel, such as natural gas, followed by GCP. C4GT proposes limitations on the duration of SU/SD events to minimize PM, PM_{10}, and $PM_{2.5}$ emissions during SU/SD.

8. Alternative Operating Scenarios:

   a. Tuning: Tuning is needed to adjust air/fuel ratios to minimize NO_x and CO. During these events, fuel flow and airflow are affected, which may affect combustion, and therefore emissions. Emission controls are working, but the inlet concentrations of pollutants may be higher than normal. BACT for tuning consists of the following:

      i. GHG - No alternate BACT was proposed since the BACT limit includes tuning.

      ii. NO_x - Technically feasible NOx controls during tuning include SCR, DLN, and GCP. Of these, SCR is most effective, followed by GCP and DLN. A combination of these controls will be employed to minimize NO_x during tuning. NOx from the GE turbines will be limited to 638 lb/turbine/calendar day basis during tuning. NOx from the Siemens turbines will be limited to 564 lb/turbine/calendar day basis during tuning.

      iii. CO - Technically feasible CO controls during tuning include oxidation catalyst, DLN (which can result in lowering CO as well as NO_x), and GCP. Of these, oxidation catalyst is most effective, followed by GCP and DLN. A combination of these controls will be employed to minimize CO during tuning. CO from the GE turbines will be limited to 194 lb/turbine/calendar day basis during tuning. CO from the Siemens turbines will be limited to 309 lb/turbine/calendar day basis during tuning.

      iv. SO_2 -No alternate BACT was proposed since the combustion of low sulfur fuel will remain BACT during tuning.

      v. VOC - Although VOC controls would be similar to CO controls, the effectiveness of these controls could be minimal. C4GT proposes limitations on the duration of tuning events to minimize VOC emissions during tuning. Compliance with CO limits constitutes compliance with VOC limits during tuning.

vi. PM, PM_{10} and $PM_{2.5}$ - Add-on controls for PM, PM_{10}, and $PM_{2.5}$, like electrostatic precipitators or baghouses are not usually applied to natural gas plants, especially for alternative operating scenarios such as tuning. So the only feasible control for PM would be the use of clean fuel, such as natural gas, followed by GCP. C4GT also proposes limitations on the duration of tuning events to minimize PM emissions during tuning.

b. Water Washing: Water washing is needed when dirt accumulates on the turbine blades and lowers the efficiency of the turbines. Water is sprayed into the turbines while they are operating. Normal controls are also operating, however, the combustion characteristics are affected and the inlet concentrations of pollutants may be higher than normal.

BACT for water washing consists of the following:

i. GHG - No alternate BACT was proposed since the BACT limit could be met during water washing.

ii. NO_x - Technically feasible NOx controls during tuning include SCR, DLN, and GCP. Of these, SCR is most effective, followed by GCP and DLN. A combination of these controls will be employed to minimize NO_x during tuning. NOx from the GE turbines will be limited to 638 lb/turbine/calendar day basis during water washing. NOx from the Siemens turbines will be limited to 564 lb/turbine/calendar day basis during water washing.

iii. CO - Technically feasible CO controls during tuning include oxidation catalyst, DLN (which can result in lowering CO as well as NO_x), and GCP. Of these, oxidation catalyst is most effective, followed by GCP and DLN. A combination of these controls will be employed to minimize CO during tuning. CO from the GE turbines will be limited to 194 lb/turbine/calendar day basis during water washing. CO from the Siemens turbines will be limited to 309 lb/turbine/calendar day basis during water washing.

iv. SO_2 - No alternative BACT was proposed since the combustion of low sulfur fuel will remain BACT during water washing.

v. VOC - Although VOC controls would be similar to CO controls, the effectiveness of these controls could be minimal. C4GT proposes limitations on the duration of water washing events to minimize VOC emissions during water washing.

vi. PM, PM_{10} and $PM_{2.5}$ - Add-on controls for PM, PM_{10}, and $PM_{2.5}$, like electrostatic precipitators or baghouses are not usually applied to natural gas plants, especially for alternative operating scenarios such as water washing. So the only feasible control for PM would be the use of clean fuel, such as natural gas, followed by GCP. C4GT proposes limitations on the duration of water washing events to minimize PM emissions during water washing.

Table 11 – Summary of BACT for the facility:

<table>
<tr><th>Pollutant</th><th>Primary BACT</th><th>Control</th><th>Compliance</th></tr>
<tr><td rowspan="5">CO_2e</td><td>Turbine
883 lb CO_2e/MWh at all times over the life of the plant (or up to 915 lb/CO_2e/MWh with agency approval)
These limits apply during initial power block heat rate evaluation:
GE Turbine
6,745 Btu/kWh (HHV) net at full load, no DB, corrected to ISO
Siemens Turbine
6,625 Btu/kWh (HHV) net at full load, no DB, corrected to ISO</td><td>Energy efficient combustion practices and low GHG fuels</td><td>Fuel monitoring
Initial heat rate evaluation
ASME Performance Test Code on Overall Plant Performance (PTC 46)</td></tr>
<tr><td>Auxiliary boiler and dew point heater</td><td>Good combustion practices, clean fuel (NG), and efficient design.</td><td>Manufacturer specifications and maintenance.</td></tr>
<tr><td>Emergency Generators</td><td>High efficiency operation and limit on annual hours of operation</td><td>fuel usage monitoring</td></tr>
<tr><td>Electrical Circuit breakers
0.5% leakage rate</td><td>Enclosed-pressure type breaker and leak detection</td><td>Audible alarm with decreased pressure.</td></tr>
<tr><td>Fugitive leaks from natural gas piping components</td><td>AVO monitoring and leak repair</td><td>recordkeeping</td></tr>
<tr><td rowspan="3">NO_x</td><td>These limits apply at all times except SU/SD
GE or Siemens Turbine
2.0 ppmvd @ 15% O_2 (1-hour avg.) with or without duct burning
Limits during SU/SD
GE Turbine – limit for each event<table><tr><td>Cold start</td><td>273 lb/turbine</td></tr><tr><td>Warm start</td><td>163 lb/turbine</td></tr><tr><td>Hot start</td><td>105 lb/turbine</td></tr><tr><td>shutdown</td><td>18 lb/turbine</td></tr></table>Siemens Turbine – limit for each event<table><tr><td>Cold start</td><td>95 lb/turbine</td></tr><tr><td>Warm start</td><td>117 lb/turbine</td></tr><tr><td>Hot start</td><td>98 lb/turbine</td></tr><tr><td>shutdown</td><td>51 lb/turbine</td></tr></table>Limits during tuning and water washing:
GE turbine
638 lb/turbine/calendar day
Siemens turbine
564 lb/turbine/calendar day</td><td>Dry Low NOx burners
SCR</td><td>Annual fuel throughput or NOx CEMS
Stack test</td></tr>
<tr><td>Auxiliary Boiler and dew point heater
0.011 lbs/MMBtu corrected to 3% O_2
Auxiliary boiler
1.2 lb/hr</td><td>Low NOx burners</td><td>Annual fuel throughput or NOx CEMS
Stack test</td></tr>
<tr><td>Emergency Generators
EG-1 4.8 g/bhp-hr NO_x+NMHC
FWP-1 3.0 g/bhp-hr NO_x+NMHC</td><td>Good combustion practices</td><td>Annual hours of operation</td></tr>
</table>

<table>
<tr><th>Pollutant</th><th>Primary BACT</th><th>Control</th><th>Compliance</th></tr>
<tr><td rowspan="3">CO</td><td>These limits apply at all times except SU/SD
GE Turbine
1.0 ppmvd @15% O_2 without DB (3-hour avg)
1.6 ppmvd @15% O_2 with DB (3-hour avg.)
Siemens Turbine
1.8 ppmvd with or without DB (3-hour avg)
Limits during SU/SD
GE Turbine – limit for each event<table><tr><td>Cold start</td><td>840 lb/turbine</td></tr><tr><td>Warm start</td><td>188 lb/turbine</td></tr><tr><td>Hot start</td><td>180 lb/turbine</td></tr><tr><td>shutdown</td><td>100 lb/turbine</td></tr></table>Siemens Turbine – limit for each event<table><tr><td>Cold start</td><td>434 lb/turbine</td></tr><tr><td>Warm start</td><td>397 lb/turbine</td></tr><tr><td>Hot start</td><td>336 lb/turbine</td></tr><tr><td>shutdown</td><td>184 lb/turbine</td></tr></table>Limits during tuning and water washing:
GE turbine
194 lb/turbine/calendar day
Siemens turbine
309 lb/turbine/calendar day</td><td>Oxidation catalyst
Good combustion practices</td><td>CO CEMS</td></tr>
<tr><td>Auxiliary boiler and dew point heater
0.037 lb/MMBtu
Auxiliary boiler
3.9 lb/hr</td><td>Clean fuel and good combustion practices</td><td>Stack test</td></tr>
<tr><td>Emergency generators
2.6 g/hp-hr</td><td>Proper operation and maintenance, clean fuel</td><td>Annual hours of operation</td></tr>
<tr><td rowspan="3">H_2SO_4</td><td>These limits apply at all times
GE Turbine
2.5 lb/hr without DB
2.7 lb/hr with DB
Siemens Turbine
2.2 lb/hr without DB
2.7 lb/hr with DB</td><td>Low sulfur fuel with a sulfur content of no more than 0.4 gr/100 scf on an annual average.</td><td>Fuel monitoring</td></tr>
<tr><td>Auxiliary boiler and dew point heater</td><td>Pipeline quality natural gas with a sulfur content of no more than 0.4 gr/100 scf on an annual average.</td><td>Fuel monitoring</td></tr>
<tr><td>FWP-1
0.00016 lb/hp-hr</td><td>ULSD fuel with 15 ppm S</td><td>Fuel monitoring</td></tr>
<tr><td rowspan="3">SO_2</td><td>State BACT
This limit applies at all times:
Turbine
0.00114 lb/MMBtu</td><td>Pipeline quality NG with a sulfur content of no more than 0.4 gr/100 scf on an annual basis.</td><td>Fuel monitoring or stack test</td></tr>
<tr><td>Auxiliary boiler and dew point heater
0.00118 lb/MMBtu</td><td>Pipeline quality NG with a sulfur content of no more than 0.4 gr/100 scf on an annual basis.</td><td>Fuel monitoring</td></tr>
<tr><td>Emergency generators</td><td>ULSD fuel with 15 ppm S</td><td>Fuel certification and annual hours of operation</td></tr>
</table>

<table>
<tr><th>Pollutant</th><th>Primary BACT</th><th>Control</th><th>Compliance</th></tr>
<tr><td rowspan="3">VOC</td><td>These limits apply at all times except SU/SD
GE Turbine
0.7 ppmvd @15% O_2 without DB (3-hour avg)
1.4 ppmvd @15% O_2 with DB (3-hour avg)
Siemens Turbine
1.0 ppmvd @15% O_2 without DB (3-hour avg)
2.0 ppmvd @15% O_2 with DB (3-hour avg)
Limits during SU/SD
GE Turbine – limit for each event<table><tr><td>Cold start</td><td>60 lb/turbine</td></tr><tr><td>Warm start</td><td>13 lb/turbine</td></tr><tr><td>Hot start</td><td>14 lb/turbine</td></tr><tr><td>shutdown</td><td>65 lb/turbine</td></tr></table>Siemens Turbine – limit for each event<table><tr><td>Cold start</td><td>37 lb/turbine</td></tr><tr><td>Warm start</td><td>34 lb/turbine</td></tr><tr><td>Hot start</td><td>34 lb/turbine</td></tr><tr><td>shutdown</td><td>56 lb/turbine</td></tr></table></td><td>Oxidation catalyst
Good combustion practices</td><td>Stack test and CO CEMS correlation</td></tr>
<tr><td>Auxiliary boiler and dew point heater
0.005 lb/MMBtu</td><td>Good combustion practices</td><td>Annual fuel throughput</td></tr>
<tr><td>Emergency generators
see NOx + NMHC limit</td><td>Good combustion practices</td><td>Annual hours of operation</td></tr>
<tr><td rowspan="4">PM</td><td>These limits apply at all times
GE Turbine
0.0046 lb/MMBtu without DB (average of three test runs)
0.0038 lb/MMBtu with DB (average of three test runs)
Siemens Turbine
0.0049 lb/MMBtu without DB (average of three test runs)
0.0056 lb/MMBtu with DB (average of three test runs)</td><td>Low sulfur/ash fuel (pipeline quality NG with no more than 0.4 gr/100scf on an annual average) and good combustion practices</td><td>Stack test</td></tr>
<tr><td>Auxiliary boiler and dew point heater
0.007 lb/MMBtu
Auxiliary boiler
0.8 lbs/hr</td><td>Low sulfur/carbon fuel and good combustion practices</td><td>Annual fuel throughput</td></tr>
<tr><td>Emergency generators
EG-1 0.15 g/hp-hr
FWP-1 0.15 g/hp-hr</td><td>Low sulfur fuel and good combustion practices</td><td>Annual hours of operation</td></tr>
<tr><td>Cooling Tower</td><td>Drift rate of 0.00050 percent of the circulating water flow with mist eliminators and a total dissolved solids content of the cooling water not to exceed 6250 mg/liter.</td><td>Monthly testing for TDS</td></tr>
<tr><td rowspan="2">PM_{10}</td><td>These limits apply at all times
GE Turbine
12.2 lbs/hr (0.0069 lb/MMBtu) without DB (average of three test runs)
17.3 lbs/hr (0.0049 lb/MMBtu) with DB (average of three test runs)
Siemens Turbine
13.7 lb/hr (0.0065 lb/MMBtu) without DB (average of three test runs)
24.2 lb/hr (0.0065 lb/MMBtu) with DB (average of three test runs)</td><td>Pipeline quality NG with no more than 0.4 gr/100scf on an annual average and good combustion practices</td><td>Stack test</td></tr>
<tr><td>Auxiliary boiler and dew point heater
0.007 lb/MMBtu
Auxiliary boiler
0.8 lbs/hr</td><td>Low sulfur/carbon fuel and good combustion practices</td><td>Annual fuel throughput</td></tr>
</table>

Pollutant	Primary BACT	Control	Compliance
	Emergency generators EG-1 0.15 g/hp-hr FWP-1 0.15 g/hp-hr	Low sulfur fuel and good combustion practices	Annual hours of operation
	Cooling Tower	Drift rate of 0.00050 percent of the circulating water flow with mist eliminators and a total dissolved solids content of the cooling water not to exceed 6250 mg/liter.	Monthly testing for TDS
$PM_{2.5}$	These limits apply at all times GE Turbine 12.2 lbs/hr (0.0069 lb/MMBtu) without DB (average of three test runs) 17.3 lbs/hr (0.0049 lb/MMBtu) with DB (average of three test runs) Siemens Turbine 13.7 lb/hr (0.0065 lb/MMBtu) without DB (average of three test runs) 24.2 lb/hr (0.0065 lb/MMBtu) with DB (average of three test runs)	Low sulfur/ash fuel (pipeline quality NG with no more than 0.4 gr/100scf on an annual average) and good combustion practices	Stack test
	Auxiliary boiler and dew point heater 0.007 lb/MMBtu Auxiliary boiler 0.8 lbs/hr	Low sulfur/carbon fuel and good combustion practices	Annual fuel throughput
	Emergency generators EG-1 0.15 g/hp-hr FWP-1 0.15 g/hp-hr	Low sulfur fuel and good combustion practices	Annual hours of operation
	Cooling Tower	Drift rate of 0.00050 percent of the circulating water flow with mist eliminators and a total dissolved solids content of the cooling water not to exceed 6250 mg/liter.	Monthly testing for TDS

The proposed control strategies are considered to be the BACT for this source type and are more stringent than NSPS standards.

IV. Initial Compliance Determination

A. Testing – stack testing is required for NO_x, CO, VOC, PM_{filt}, PM_{10}, and $PM_{2.5}$ from the turbines and NO_x and CO from the auxiliary boiler and dew point heater to show compliance with the BACT limits. An initial compliance evaluation using ASME Performance Test Code on Overall Plant Performance (ASME PTC 46-1996) (or equivalent) is to be conducted on the turbine power blocks to show compliance with the heat rate limit.

The permit allows the permittee to use the fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel to verify that the sulfur content of the natural gas is 0.4 grain or less of total sulfur per 100 scf. Alternatively, per 40 CFR 60.4370, the permit allows C4GT to determine the sulfur content of the natural gas by testing using two custom monitoring schedules or an EPA-approved schedule. The permit also requires the permittee to obtain fuel supplier certification for each shipment of distillate oil used in the emergency units.

An initial stack test for formaldehyde from the combustion turbines will be required to verify the vendor-supplied emission factor proposed in the permit application

B. VEEs – an initial VEE will be required for the combustion turbines, auxiliary boiler, and dew point heater.

V. Continuing Compliance Determination

A. CEMS – will be required for NO_x (NSPS) and CO from the turbines. Requirements for CEMS performance evaluations, quality assurance, and excess emissions reports will be included in the permit.

CEMS or a Virginia DEQ-approved operational monitoring plan is required for NOx from the Auxiliary Boiler (NSPS).

The permit requires that the CT stacks be equipped with CEMS meeting the requirements of 40 CFR Part 75 (Acid Rain program) for NO_x. In addition to providing a means to demonstrate compliance with the permit NO_x limits, the CEMS will satisfy the NSPS Subpart KKKK requirement to monitor NO_x emissions using a CEMS. The permit also requires that the CT stacks be equipped with CEMS meeting the monitoring requirements in 40 CFR 60.13 for CO.

In addition to the CEMS, the draft permit requires C4GT to conduct extensive, continuous monitoring of key operational parameters on the control devices to assure proper operation and performance. Fuel tracking for the turbines (including fuel sulfur content), auxiliary boiler, dew point heater, and emergency units is required to show compliance with other emission limits.

CO_2 monitoring can be in the form of CEMS or emission factors derived from testing for CO_2 and Part 98 factors for N_2O and CH_4 monitoring.

Additional stack testing for NOx, PM_{10}, $PM_{2.5}$, VOC and CO will be required every five years by the Federal Operating Permit periodic monitoring requirements.

B. Recordkeeping – The following records will be kept by the permittee for the most recent five years:

1. Annual hours of operation of the emergency fire water pump (FWP-1) and emergency generator (EG-1) for emergency purposes and for maintenance checks and readiness testing, calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months;

2. All fuel supplier certifications for the S15 ULSD fuel used in the emergency units (EG-1 and FWP-1);

3. Monthly and annual throughput of natural gas to the two combustion turbines and associated duct burners (CT-1, CT-2), calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months;

4. Monthly and annual throughput of natural gas to the auxiliary boiler (B-1) and the dew point heater (DPH-1), calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months;

5. Fuel sulfur monitoring records for natural gas combusted in each combustion turbine and associated duct burner (CT-1, CT-2), auxiliary boiler (B-1), and dew point heater (DPH-1);

6. Net power output of the combined cycle combustion turbine and associated steam turbine (CT-1, CT-2);

7. Continuous monitoring system emissions data, calibrations and calibration checks, percent operating time, and excess emissions;

8. Operation and control device monitoring records for each SCR system and oxidation catalyst as required in Conditions 2 and 5;

9. Records of alternative operating scenarios as required by Condition 10;

10. The occurrence and duration of any startup, shutdown, or malfunction of the affected facility, any malfunction of the air pollution control equipment, or any periods during which a continuous emission monitoring system is inoperative;

11. Monthly log of dissolved solids content of the cooling water to the cooling tower (CWT-1);

12. Results of daily AVO inspections for fugitive natural gas leak detection, dates and results of first and final repair attempt, any repairs performed to the piping components (valves and flanges), and the list of long-term leaking components and reason for each delay.

13. Scheduled and unscheduled maintenance, and operator training.

14. Results of all stack tests, visible emission evaluations, and performance evaluations.

15. Manufacturer's instructions for proper operation of equipment.

16. Records showing the circuit breakers are operating in accordance with the manufacturer's specifications (see Condition 21).

C. Further Testing

1. Annual testing for SO_2 from the turbines can be done instead of fuel monitoring.

2. After the initial test for PM, PM_{10}, $PM_{2.5}$ and, VOC, additional testing will be required every five years as part of the Title V periodic monitoring plan.

VI. Public Participation

The applicant held a public information session on July 22, 2016 at the Charles City County Government Building, Charles City County to provide the community with information about the project.

Pursuant to 9 VAC 5-80-1775 (Article 8) of the Regulations, the proposed project is subject to a public comment period of at least 30 days, followed by a public hearing.

An information meeting and public hearing is scheduled to be held on April 9, 2018 at the Charles City County Government Building, followed by 15 more days of public comment.

VII. Other Considerations

A. File Consistency Review – This is the first permit action for this source

B. PRO Policy Consistency Review – A review of similar combustion turbine permits proposed or issued in the USA was conducted. The most recent boilerplate was used for this permit.

C. Confidentiality – The source has not claimed confidentiality of any data.

D. Permit History – This is the first permit issued for this source

VIII. Recommendations

Based on the information submitted, it is recommended that this permit be issued.

Regional Engineer:____________________________ Date: March 6, 2018

Reviewing Engineer:___________________________ Date: March 6, 2018

Attachments:

Appendix A – Calculation sheets
Appendix B – Modeling Memo

Appendix A

Emission Calculations

Facility C4GT LLC - Siemens
Location Charles City Co.
Reg. No. 52588
Eng AMS

Emissions from EACH of the combustion turbines CT-1, CT-2

Capacity	306 MW			
	3116 MMBtu/hr	natural gas	8760	hrs/yr

Natural Gas Combustion No Duct Firing		Uncontrolled		Controlled @ 8760 hours			
pollutant	EF (lb/MMBtu)	lb/hr	ton/yr	Control	%	lb/hr	tons/yr
PMfilt	0.0049	15.27	66.88	None	0	15.27	66.88
PM10*	0.0065	13.63	59.70	None	0	13.63	59.70
PM2.5	0.0065	13.63	59.70	None	0	13.63	59.70
CO	0.0413	128.54	562.98	Ox Cat	90	12.85	56.30
NOx	0.1253	390.28	1709.42	SCR	94	23.42	102.57
SO2	0.00114	3.56	15.61	None	0	3.56	15.61
VOC	0.00132	4.10	17.96	None	0	4.10	17.96
H2SO	0.00070	2.19	9.61	None	0	2.19	9.61
CO_2	116.9800	364,509.68	1,596,552.40	Efficiency	0	364,509.68	1,596,552.40
CH_4	0.0022	6.87	30.09	Efficiency	0	6.87	30.09
N2O	0.00022	0.69	3.01	Efficiency	0	0.69	3.01
CO2-e	117.10	364,886.14	1,598,201.28	Efficiency	0	364,886.14	1,598,201.28

Emissions based on engineering judgement and BACT determinations
*PM10 includes contributions from turbines, and H2SO4 and condensable VOC.
Worst case lb/MMBtu for PM10/PM2.5 is at 100°F, 77% relative humidity, 14.6 psia, and 41% load.
Worst case lb/hr for PM10/PM2.5 is at 10°F, 7% relative humidity, 14.6 psia, and 100% load.

Facility	C4GT LLC - Siemens
Location	Charles City Co.
Reg. No.	52588
Eng	AMS

HAP Emissions from each turbine

Combustion Turbines 3116 MMBtu/hr EACH (natural gas)

NATURAL GAS		**Uncontrolled**		**Control**	**Controlled**	
Pollutant	**EF**	**Emissions**		**efficiency**	**Emissions**	
	(Lb/MMBtu)	**lb/hr**	**tpy**	**%**	**lb/hr**	**tpy**
1,3-Butadiene	4.30E-07	1.34E-03	5.87E-03		1.34E-03	5.87E-03
Acetaldehyde	4.00E-05	1.25E-01	5.46E-01		1.25E-01	5.46E-01
Acrolein	6.40E-06	1.99E-02	8.73E-02		1.99E-02	8.73E-02
Benzene	1.20E-05	3.74E-02	1.64E-01		3.74E-02	1.64E-01
Ethyl Benzene	3.20E-05	9.97E-02	4.37E-01		9.97E-02	4.37E-01
Formaldehyde*	2.40E-04	7.48E-01	3.28E+00		7.48E-01	3.28E+00
Naphthalene	1.30E-06	4.05E-03	1.77E-02		4.05E-03	1.77E-02
PAH	2.20E-06	6.86E-03	3.00E-02		6.86E-03	3.00E-02
Propylene Oxide	2.90E-05	9.04E-02	3.96E-01		9.04E-02	3.96E-01
Toluene	1.30E-04	4.05E-01	1.77E+00		4.05E-01	1.77E+00
Xylenes	6.40E-05	1.99E-01	8.73E-01		1.99E-01	8.73E-01

METALS		**Uncontrolled**		**Control**	**Controlled**	
Pollutant	**EF**	**Emissions**		**efficiency**	**Emissions**	
	(Lb/MMBtu)	**lb/hr**	**tpy**	**%**	**lb/hr**	**tpy**
lead	4.90E-07	1.53E-03	6.69E-03	0.00	1.53E-03	6.69E-03

*All emission factors are from AP-42 Table except formaldehyde which is based on manufacturer's information (91 ppbvd@15% O2 using dry low NOx combustion)

Facility C4GT LLC - Siemens
Location Charles City Co.
Reg. No. 52588
Eng AMS

Emissions from EACH of the two duct burners associated with the turbines

Capacity

991 MMBtu/hr	natural gas	8760 hrs/yr

Natural Gas Combustion		Uncontrolled @ 8760 hrs/yr		Controlled @ 8760 hours			
pollutant	EF (lb/MMBtu)	lb/hr	ton/yr	Control	%	lb/hr	tons/yr
PM	0.0106	10.51	46.04	None	0	10.51	46.04
PM10*	0.0106	10.51	46.04	None	0	10.51	46.04
PM2.5*	0.0106	10.51	46.04	None	0	10.51	46.04
CO	0.0325	32.15	140.83	Ox Cat	90	3.22	14.08
NOx	0.0582	57.67	252.57	SCR	90.0	5.77	25.26
SO2	0.00085	0.84	3.69	None	0	0.84	3.69
VOC	0.0136	13.48	59.02	Ox Cat	54.5	6.13	26.85
H2SO4**	0.0005	0.51	2.21		0	0.51	2.21
CO_2	116.98	115,902.81	507,654.29	Efficiency	0	115,902.81	507,654.29
CH_4	0.0022	2.18	9.57	Efficiency	0	2.18	9.57
N2O	0.0002	0.22	0.96	Efficiency	0	0.22	0.96
CO2-e	117.10	116,022.51	508,178.59	Efficiency	0	116,022.51	508,178.59

*Worst case lb/hr for PM10/PM2.5 is at 95°F, 76% relative humidity and 100% load. Worst case lb/MMBtu is at 100°F, 77% relative humidity and 100% load. Includes sulfates from SCR and OC controls.
**H2SO4 emissions include those from OC and SCR
CO2e (GHG) emission factors from Part 98 - Mandatory Greenhouse Gas Reporting, Section C

Facility C4GT LLC - Siemens
Location Charles City Co.
Reg. No. 52588
Eng AMS

HAP Emissions from Duct Burner

Duct Burners (each) 990.8139 MMBtu/hr EACH (natural gas)
8760 hrs/yr

All emission factors are from AP-42 Table

NATURAL GAS Pollutant	**EF (Lb/MMBtu)**	**Uncontrolled Emissions lb/hr**	**tpy**	**Control efficiency**	**Controlled Emissions lb/hr**	**tpy**
2-methylnapthalene	2.35E-08	2.33E-05	1.02E-04	55	1.06E-05	4.64E-05
3-methylchloranthren	1.76E-09	1.74E-06	7.64E-06	55	7.93E-07	3.48E-06
7,12-Dimethylbenz(a)a	1.57E-08	1.56E-05	6.81E-05	55	7.08E-06	3.10E-05
Acenaphthene	1.76E-09	1.74E-06	7.64E-06	55	7.93E-07	3.48E-06
Acenaphthylene	1.76E-09	1.74E-06	7.64E-06	55	7.93E-07	3.48E-06
Anthracene	2.35E-09	2.33E-06	1.02E-05	55	1.06E-06	4.64E-06
Benz(a)anthracene	1.76E-09	1.74E-06	7.64E-06	55	7.93E-07	3.48E-06
Benzene	2.06E-06	2.04E-03	8.94E-03	55	9.29E-04	4.07E-03
Benzo(a)pyrene	1.18E-09	1.17E-06	5.12E-06	55	5.32E-07	2.33E-06
Benzo(b)flouoranthen	1.76E-09	1.74E-06	7.64E-06	55	7.93E-07	3.48E-06
Benzo(g,h,l)perylene	1.18E-09	1.17E-06	5.12E-06	55	5.32E-07	2.33E-06
Benzo(k)fluoranthene	1.76E-09	1.74E-06	7.64E-06	55	7.93E-07	3.48E-06
Chrysene	1.76E-09	1.74E-06	7.64E-06	55	7.93E-07	3.48E-06
Dibenzo(ah)anthracen	1.18E-09	1.17E-06	5.12E-06	55	5.32E-07	2.33E-06
Dichlorobenzene	1.18E-06	1.17E-03	5.12E-03	55	5.32E-04	2.33E-03
Fluoranthene	2.94E-09	2.91E-06	1.28E-05	55	1.33E-06	5.81E-06
Fluorene	2.75E-09	2.72E-06	1.19E-05	55	1.24E-06	5.43E-06
Formaldehyde	7.35E-05	7.28E-02	3.19E-01	55	3.31E-02	1.45E-01
Hexane	1.76E-03	1.74E+00	7.64E+00	55	7.93E-01	3.48E+00
Indeno(123-cd)pyrene	1.76E-09	1.74E-06	7.64E-06	55	7.93E-07	3.48E-06
Naphthalene	5.98E-07	5.93E-04	2.60E-03	55	2.70E-04	1.18E-03
Phenanathrene	1.67E-08	1.65E-05	7.25E-05	55	7.53E-06	3.30E-05
Pyrene	4.90E-09	4.85E-06	2.13E-05	55	2.21E-06	9.68E-06
Toluene	3.33E-06	3.30E-03	1.45E-02	55	1.50E-03	6.58E-03

Totals
Total annual HAP based on 8760 hrs on natural gas

METALS Pollutant	**EF (Lb/MMBtu)**	**Uncontrolled Emissions lb/hr**	**tpy**
Arsenic	1.96E-07	1.94E-04	8.51E-04
Beryllium	1.18E-08	1.17E-05	5.12E-05
cadmium	1.08E-06	1.07E-03	4.69E-03
chromium	1.37E-06	1.36E-03	5.95E-03
cobalt	8.24E-08	8.16E-05	3.58E-04
lead	4.90E-07	4.85E-04	2.13E-03
manganese	3.73E-07	3.70E-04	1.62E-03
mercury	2.55E-07	2.53E-04	1.11E-03
nickel	2.06E-06	2.04E-03	8.94E-03
selenium	2.35E-08	2.33E-05	1.02E-04

Facility C4GT LLC - Siemens
Location Charles City Co.
Reg. No. 52588
Eng AMS

Start Up/Shut down Emissions

Pollutant	Start up lb/hr	Start up TPY	Shut down lb/hr	Shut down TPY	Totals lb/hr	Totals TPY
PM	8.13	0.81	4.70	0.37	8.13	1.18
CO	473.00	43.69	290.50	23.00	473.00	66.69
NOx	126.80	12.58	80.20	6.35	126.80	18.93
SO2		0.17		0.05		0.22
VOC	40.30	4.22	87.30	6.92	87.30	11.14
H2SO4		0.1		0.03		0.13
CO2						4.06E+04
CH4						7.60E-01
N2O						8.00E-02
CO2e						4.06E+04

Emissions were calculated based on estimated duration and frequency of cold start, warm start, hot start and shutdowns. See application, Section 3, Tables 3-2, 3-3, and 3-4 for more detailed calculations.

Facility	C4GT LLC - Siemens
Location	Charles City Co.
Reg. No.	52588
Eng	AMS

Emissions from Control Equipment

SCR

H_2SO_4	0.008	lb/hr
NH_3	9.32	lb/hr
Amm Sulfa	3.11	lb/hr

Oxidation Catalyst

H_2SO_4	0.069	lb/hr

Facility C4GT LLC - Siemens
Location Charles City Co.
Reg. No. 52588
Eng AMS

Total Emissions from each turbine including duct burning and su/sd

	Turbine (each)		duct burners		SU/SD		Totals (worst case)*	
pollutant	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
PM	15.27	66.88	10.51	46.04	8.13	1.18	25.78	112.92
PM10	13.63	59.70	10.51	46.04	8.13	1.18	24.14	105.74
PM2.5	13.63	59.70	10.51	46.04	8.13	1.18	24.14	105.74
CO	12.85	56.30	3.22	14.08	473.00	66.69	16.07	134.09
NOx	23.42	102.57	5.77	25.26	126.80	18.93	29.18	141.34
SO2	3.56	15.61	0.84	3.69	0.00	0.00	4.41	19.30
VOC	4.10	17.96	6.13	26.85	87.30	11.14	10.23	54.05
H2SO	2.19	9.61	0.51	2.21	8.13	1.18	2.70	11.82
CO_2	3.65E+05	1.60E+06	1.16E+05	5.08E+05		4.06E+04	4.80E+05	2.10E+06
CH_4	6.87E+00	3.01E+01	2.18E+00	9.57E+00		7.60E-01	9.05E+00	3.97E+01
N2O	6.87E-01	3.01E+00	2.18E-01	9.57E-01		8.00E-02	9.05E-01	3.97E+00
CO2-e	3.65E+05	1.60E+06	1.16E+05	5.08E+05		4.06E+04	4.81E+05	2.11E+06

*Worst case annual emissions are based on either the (hourly emissions from the turbine + duct burner x 8760 hrs/yr) **or** the (hourly emissions from the turbine + duct burner x 8389 hrs/yr) + annual SU/SD emissions

Facility C4GT LLC - GE7FA.02
Location Charles City Co.
Reg. No. 52588
Eng AMS

Emissions from EACH of the combustion turbines CT-1, CT-2, CT-3

Capacity	352 MW		
	3482 MMBtu/hr	natural gas	8760 hrs/yr

Natural Gas Combustion No Duct Firing		Uncontrolled		Controlled @ 8760 hours			
pollutant	EF (lb/MMBtu)	lb/hr	ton/yr	Control	%	lb/hr	tons/yr
PM	0.0046	10.88	47.64	None	0	10.88	47.64
PM10*	0.0069	12.18	53.35	None	0	12.18	53.35
PM2.5	0.0069	12.18	53.35	None	0	12.18	53.35
CO	0.0232	80.89	354.28	Ox Cat	90	8.09	35.43
NOx	0.0954	332.18	1454.96	SCR	92	26.57	116.40
SO2	0.00114	3.97	17.39	None	0	3.97	17.39
VOC	0.0009	3.24	14.18	Ox Cat	0	3.24	14.18
H2SO	0.00070	2.44	10.68	None	0	2.44	10.68
CO_2	116.9774	407,315.21	1,784,040.61	Efficiency	0	407,315.21	1,784,040.61
CH_4	0.0022	7.68	33.62	Efficiency	0	7.68	33.62
N_2O	0.00022	0.77	3.36	Efficiency	0	0.77	3.36
CO2-e	117.10	407,735.88	1,785,883.16	Efficiency	0	407,735.88	1,785,883.16

Emissions based on engineering judgement and BACT determinations
*PM10 includes contributions from turbines, and H2SO4 and condensable VOC.
Worst case lb/MMBtu for PM/PM10/PM2.5 is at 59°F, 60% relative humidity, 14.6 psia, and 30% load.
Worst case lb/hr for PM/PM10/PM2.5 is at 10°F, 44.2% relative humidity, 14.6 psia, and 100% load.

Facility C4GT LLC - Siemens
Location Charles City Co.
Reg. No. 52588 **HAP Emissions from each turbine**
Eng AMS

Combustion Turbines 3482 MMBtu/hr EACH (natural gas)

NATURAL GAS		**Uncontrolled**		**Control**	**Controlled**	
Pollutant	**EF**	**Emissions**		**efficiency**	**Emissions**	
	(Lb/MMBtu)	**lb/hr**	**tpy**	**%**	**lb/hr**	**tpy**
1,3-Butadiene	4.30E-07	1.50E-03	6.56E-03		1.50E-03	6.56E-03
Acetaldehyde	4.00E-05	1.39E-01	6.10E-01		1.39E-01	6.10E-01
Acrolein	6.40E-06	2.23E-02	9.76E-02		2.23E-02	9.76E-02
Benzene	1.20E-05	4.18E-02	1.83E-01		4.18E-02	1.83E-01
Ethyl Benzene	3.20E-05	1.11E-01	4.88E-01		1.11E-01	4.88E-01
Formaldehyde*	2.20E-04	7.66E-01	3.36E+00		7.66E-01	3.36E+00
Naphthalene	1.30E-06	4.53E-03	1.98E-02		4.53E-03	1.98E-02
Propylene Oxide	2.90E-05	1.01E-01	4.42E-01		1.01E-01	4.42E-01
Toluene	1.30E-04	4.53E-01	1.98E+00		4.53E-01	1.98E+00
Xylenes	6.40E-05	2.23E-01	9.76E-01		2.23E-01	9.76E-01

METALS		**Uncontrolled**		**Control**	**Controlled**	
Pollutant	**EF**	**Emissions**		**efficiency**	**Emissions**	
	(Lb/MMBtu)	**lb/hr**	**tpy**	**%**	**lb/hr**	**tpy**
lead	4.90E-07	1.71E-03	7.48E-03	0.00	1.71E-03	7.48E-03

*All emission factors are from AP-42 Table except formaldehyde which is based on manufacturer's information (91 ppbvd@15% O2 using dry low NOx combustion)

Facility C4GT LLC - GE7FA.02
Location Charles City Co.
Reg. No. 52588
Eng AMS

Emissions from EACH of the two duct burners associated with the turbines

Capacity

475.1 MMBtu/hr	natural gas 8760 hrs/yr

Natural Gas Combustion		Uncontrolled @ 8760 hrs/yr		Controlled @ 8760 hours			
pollutant	EF (lb/MMBtu)	lb/hr	ton/yr	Control	%	lb/hr	tons/yr
PM	0.0108	5.15	22.56	None	0	5.15	22.56
PM10*	0.0108	5.15	22.56	None	0	5.15	22.56
PM2.5*	0.0108	5.15	22.56	None	0	5.15	22.56
CO	0.1283	60.95	266.97	Ox Cat	90	6.10	26.70
NOx	0.069	32.78	143.58	SCR	92.0	2.62	11.49
SO2	0.00080	0.38	1.66	None	0	0.38	1.66
VOC	0.0082	3.90	17.06	Ox Cat	0	3.90	17.06
H2SO4**	0.00049	0.23	1.03		0	0.23	1.03
CO_2	116.977	55,572.62	243,408.06	Efficiency	0	55,572.62	243,408.06
CH_4	0.0022	1.05	4.59	Efficiency	0	1.05	4.59
N2O	0.0002	0.10	0.46	Efficiency	0	0.10	0.46
CO2-e	117.10	55,630.01	243,659.45	Efficiency	0	55,630.01	243,659.45

*Worst case lb/hr for PM10/PM2.5 is at 95°F, 42% relative humidity and 100% load. Worst case lb/MMBtu is at 10°F, 44% relative humidity and 100% load.

**H2SO4 emissions include those from OC and SCR

CO2e (GHG) emission factors from Part 98 - Mandatory Greenhouse Gas Reporting, Section C

Facility	C4GT LLC - GE7FA.02
Location	Charles City Co.
Reg. No.	52588
Eng	AMS

HAP Emissions from Duct Burner

Duct Burners (each) 475.0715 MMBtu/hr EACH (natural gas)
8760 hrs/yr

All emission factors are from AP-42 Table

NATURAL GAS		**Uncontrolled**		**Control**	**Controlled**	
Pollutant	**EF**	**Emissions**		**efficiency**	**Emissions**	
	(Lb/MMBtu)	**lb/hr**	**tpy**		**lb/hr**	**tpy**
2-methylnapthalene	2.35E-08	1.12E-05	4.89E-05		1.12E-05	4.89E-05
3-methylchloranthren	1.76E-09	8.36E-07	3.66E-06		8.36E-07	3.66E-06
7,12-Dimethylbenz(a)a	1.57E-08	7.46E-06	3.27E-05		7.46E-06	3.27E-05
Acenaphthene	1.76E-09	8.36E-07	3.66E-06		8.36E-07	3.66E-06
Acenaphthylene	1.76E-09	8.36E-07	3.66E-06		8.36E-07	3.66E-06
Anthracene	2.35E-09	1.12E-06	4.89E-06		1.12E-06	4.89E-06
Benz(a)anthracene	1.76E-09	8.36E-07	3.66E-06		8.36E-07	3.66E-06
Benzene	2.06E-06	9.79E-04	4.29E-03		9.79E-04	4.29E-03
Benzo(a)pyrene	1.18E-09	5.61E-07	2.46E-06		5.61E-07	2.46E-06
Benzo(b)flouoranthen	1.76E-09	8.36E-07	3.66E-06		8.36E-07	3.66E-06
Benzo(g,h,l)perylene	1.18E-09	5.61E-07	2.46E-06		5.61E-07	2.46E-06
Benzo(k)fluoranthene	1.76E-09	8.36E-07	3.66E-06		8.36E-07	3.66E-06
Chrysene	1.76E-09	8.36E-07	3.66E-06		8.36E-07	3.66E-06
Dibenzo(ah)anthracen	1.18E-09	5.61E-07	2.46E-06		5.61E-07	2.46E-06
Dichlorobenzene	1.18E-06	5.61E-04	2.46E-03		5.61E-04	2.46E-03
Fluoranthene	2.94E-09	1.40E-06	6.12E-06		1.40E-06	6.12E-06
Fluorenen	2.75E-09	1.31E-06	5.72E-06		1.31E-06	5.72E-06
Formaldehyde	7.35E-05	3.49E-02	1.53E-01		3.49E-02	1.53E-01
Hexane	1.76E-03	8.36E-01	3.66E+00		8.36E-01	3.66E+00
Indeno(123-cd)pyrene	1.76E-09	8.36E-07	3.66E-06		8.36E-07	3.66E-06
Naphthalene	5.98E-07	2.84E-04	1.24E-03		2.84E-04	1.24E-03
Phenanathrene	1.67E-08	7.93E-06	3.47E-05		7.93E-06	3.47E-05
Pyrene	4.90E-09	2.33E-06	1.02E-05		2.33E-06	1.02E-05
Toluene	3.33E-06	1.58E-03	6.93E-03		1.58E-03	6.93E-03

Totals

Total annual HAP based on 8760 hrs on natural gas

METALS		**Uncontrolled**	
Pollutant	**EF**	**Emissions**	
	(Lb/MMBtu)	**lb/hr**	**tpy**
Arsenic	1.96E-07	9.31E-05	4.08E-04
Beryllium	1.18E-08	5.61E-06	2.46E-05
cadmium	1.08E-06	5.13E-04	2.25E-03
chromium	1.37E-06	6.51E-04	2.85E-03
cobalt	8.24E-08	3.91E-05	1.71E-04
lead	4.90E-07	2.33E-04	1.02E-03
manganese	3.73E-07	1.77E-04	7.76E-04
mercury	2.55E-07	1.21E-04	5.31E-04
nickel	2.06E-06	9.79E-04	4.29E-03
selenium	2.35E-08	1.12E-05	4.89E-05

Facility C4GT LLC - GE7FA.02
Location Charles City Co.
Reg. No. 52588
Eng AMS

Start Up/Shut down Emissions

	Start up		Shut down		Totals	
Pollutant	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
PM	12.05	0.86	15.00	0.94	15.00	1.80
PM10/2.5	12.05	0.86	15.00	0.94	15.00	1.80
CO	840.00	25.95	200.00	12.50	840.00	38.45
NOx	272.73	15.11	35.00	2.19	272.73	17.30
SO2	1.60	0.09	0.80	0.05	1.60	0.14
VOC	60.00	1.90	130.00	8.13	130.00	10.03
H2SO4	0.98	0.05	0.5	0.03	0.98	0.08
CO2						3.33E+04
CH4						6.30E-01
N2O						6.00E-02
CO2e						3.33E+04

Emissions were calculated based on estimated duration and frequency of cold start, warm start, hot start and shutdowns. See application, Section B, Tables B-3. and B-4 for more detailed calculations.

Facility C4GT LLC - GE7FA.02
Location Charles City Co.
Reg. No. 52588
Eng AMS

Total Emissions from each turbine including duct burning and su/sd

	Turbine (each)		duct burners		SU/SD		Totals (worst case)	
pollutant	lb/hr	TPY	lb/hr	TPY	lb/hr*	TPY	lb/hr	TPY**
PM	10.88	47.64	5.15	22.56	15.00	1.80	16.03	70.20
PM10	12.18	53.35	5.15	22.56	15.00	1.80	17.33	75.90
PM2.5	12.18	53.35	5.15	22.56	15.00	1.80	17.33	75.90
CO	8.09	35.43	6.10	26.70	840.00	38.45	14.18	98.67
NOx	26.57	116.40	2.62	11.49	272.73	17.30	29.20	141.27
SO2	3.97	17.39	0.38	1.66	1.60	0.14	4.35	19.05
VOC	3.24	14.18	3.90	17.06	130.00	10.03	7.13	40.32
H2SO	2.44	10.68	0.23	1.03	0.98	0.08	2.67	11.70
CO_2	4.07E+05	1.78E+06	5.56E+04	2.43E+05		3.33E+04	4.63E+05	2.03E+06
CH_4	7.68E+00	3.36E+01	1.05E+00	4.59E+00		6.30E-01	8.72E+00	3.82E+01
N2O	7.68E-01	3.36E+00	1.05E-01	4.59E-01		6.00E-02	8.72E-01	3.82E+00
CO2-e	4.08E+05	1.79E+06	5.56E+04	2.44E+05		3.33E+04	4.63E+05	2.03E+06

* Hourly SU/SD emissions are used to determine annual emissions only. They do not appear in the permit.
Worst case annual emissions are based on either the hourly emissions from the turbine + duct burner x 8760 hrs/yr **or the hourly emissions from the turbine + duct burner x 8492 hrs/yr + annual SU/SD emissions

Facility C4GT LLC
Location Charles City Co.
Reg. No. 52588
Eng AMS

Auxilliary Boiler B-1

	BTU Rating:	105.0	MMBtu/hr
	Fuel Rating	0.103	MMcf/hr
Natural Gas	Throughput @8760:	901.76	MMcf/yr
	Fuel Sulfur Content:	0.40	gr/100 cf
	Heat Content:	1020.00	MMBtu/mmcf

Pollutant	Emission Factor lb/MMBtu	Reference	UNCONTROLLED EMISSIONS Hourly (lb/hr)	8760 hrs (ton/yr)	Thruput (ton/yr)	Control Technology	Control Eff. %	PERMIT EMISSION LIMITS (lb/hr)	(ton/yr)
Criteria Pollutants									
PM	0.0070	(2)	0.74	3.22	3.22	None	0.00	0.74	3.22
PM10	0.0070	(2)	0.74	3.22	3.22	None	0.00	0.74	3.22
PM2.5	0.0070	(2)	0.74	3.22	3.22	None	0.00	0.74	3.22
CO	0.037	(2)	3.89	17.02	17.02	None	0.00	3.89	17.02
NOx	0.011	(2)	1.16	5.06	5.06	None	0.00	1.16	5.06
SO2	0.00118	(1)(3)	0.12	0.54	0.54	None	0.00	0.12	0.54
VOC Total	0.005	(2)	0.53	2.30	2.30	None	0.00	0.53	2.30
H2SO4	9.01E-05	(3)	9.46E-03	4.14E-02	4.14E-02	None	0.00	9.46E-03	0.04
CO2	116.9774	(4)	12282.62	53797.89	53797.89	None	0.00	12282.62	53797.89
CH4	0.0022	(4)	0.23	1.01	1.01	None	0.00	0.23	1.01
N20	0.00022	(4)	0.02	0.10	0.10	None	0.00	0.02	0.10
CO2-e	117.10	(4)	12295.31	53853.46	53853.46	None	0.00	12295.31	53853.46

Notes:
(1) AP-42 Section 1.4
(2) Vendor/B&V 2016
(3) sulfur content of 0.4 gr/100 dscf; H2SO4 is based on 5% conversion of SO2 to SO3 and 100% conversion of SO3 to H2SO4
(4) EPA Rule "Mandatory Reporting of Greenhouse Gases", Federal Register Vol. 74, NO. 209, October 2009
Global Warming Potential from Table A-1 of 40 CFR 98 Subpart A as of December 2014

Facility C4GT LLC
Location Charles City Co.
Reg. No. 52588
Eng AMS

HAP from Auxilliary boiler B-1 Heat rating on natural gas
105 MMBtu/hr
8760 hrs/yr

	EF lb/MMBtu	lb/hr	TPY
2-methylnapthalene	2.35E-08	2.47E-06	1.08E-05
3-methylchloranthrene	1.76E-09	1.85E-07	8.09E-07
7,12-Dimethylbenz(a)anthracene	1.57E-08	1.65E-06	7.22E-06
Acenaphthene	1.76E-09	1.85E-07	8.09E-07
Acenaphthylene	1.76E-09	1.85E-07	8.09E-07
Anthracene	2.35E-09	2.47E-07	1.08E-06
Benz(a)anthracene	1.76E-09	1.85E-07	8.09E-07
Benzene	2.06E-06	2.16E-04	9.47E-04
Benzo(a)pyrene	1.18E-09	1.24E-07	5.43E-07
Benzo(b)flouoranthene	1.76E-09	1.85E-07	8.09E-07
Benzo(g,h,l)perylene	1.18E-09	1.24E-07	5.43E-07
Benzo(k)fluoranthene	1.76E-09	1.85E-07	8.09E-07
Chrysene	1.76E-09	1.85E-07	8.09E-07
Dibenzo(ah)anthracene	1.18E-09	1.24E-07	5.43E-07
Dichlorobenzene	1.18E-06	1.24E-04	5.43E-04
Fluoranthene	2.94E-09	3.09E-07	1.35E-06
Fluorene	2.75E-09	2.89E-07	1.26E-06
Formaldehyde	7.35E-05	7.72E-03	3.38E-02
Hexane*	1.28E-06	1.34E-04	5.89E-04
Indeno(123-cd)pyrene	1.76E-09	1.85E-07	8.09E-07
Naphthalene	5.98E-07	6.28E-05	2.75E-04
Phenanathrene	1.67E-08	1.75E-06	7.68E-06
Pyrene	4.90E-09	5.15E-07	2.25E-06
Toluene	3.33E-06	3.50E-04	1.53E-03

METALS

Arsenic	1.96E-07	2.06E-05	9.01E-05
Beryllium	1.18E-08	1.24E-06	5.43E-06
cadmium	1.08E-06	1.13E-04	4.97E-04
chromium	1.37E-06	1.44E-04	6.30E-04
cobalt	8.24E-08	8.65E-06	3.79E-05
lead	4.90E-07	5.15E-05	2.25E-04
manganese	3.73E-07	3.92E-05	1.72E-04
mercury	2.55E-07	2.68E-05	1.17E-04
nickel	2.06E-06	2.16E-04	9.47E-04
selenium	2.35E-08	2.47E-06	1.08E-05

Emission Factors from AP-42 Section 1.4

*Hexane EF based on AB2588 Combustion Emission Factors, Ventura Co. APCD

Facility C4GT LLC
Location Charles City Co.
Reg. No. 52588
Eng AMS

One Dew Point Heater
DPH-1

Natural Gas

BTU Rating:	16.0	MMBtu/hr
Fuel Rating	0.0157	MMcf/hr
Process Throughput:	137.412	MMcf/yr
Fuel Sulfur Content:	0.40	gr/dscf
Heat Content:	1020.00	MMBtu/mmcf

Pollutant	Emission Factor lb/MMBtu	Reference	UNCONTROLLED EMISSIONS Hourly (lb/hr)	8760 hrs (ton/yr)	Thruput (ton/yr)	Control Technology	Control Eff. %	PERMIT EMISSION LIMITS (lb/hr)	(ton/yr)
Criteria Pollutants									
PM	0.007	(1)	0.11	0.49	0.49	None	0.00	0.11	0.49
PM10	0.007	(1)	0.11	0.49	0.49	None	0.00	0.11	0.49
PM2.5	0.007	(1)	0.11	0.49	0.49	None	0.00	0.11	0.49
CO	0.037	(1)	0.59	2.59	2.59	None	0.00	0.59	2.59
NOx	0.011	(1)	0.18	0.77	0.77	None	0.00	0.18	0.77
SO2	0.00118	(2)	0.02	0.08	0.08	None	0.00	0.02	0.08
VOC Total	0.005	(1)	0.08	0.35	0.35	None	0.00	0.08	0.35
H2SO4	9.01E-05	(3)	1.44E-03	6.31E-03	6.31E-03	None	0.00	1.44E-03	6.31E-03
CO2	116.9774	(4)	1.87E+03	8.20E+03	8.20E+03	None	0.00	1.87E+03	8.20E+03
CH4	0.0022	(4)	3.53E-02	1.55E-01	1.55E-01	None	0.00	3.53E-02	1.55E-01
N20	0.00022	(4)	3.53E-03	1.55E-02	1.55E-02	None	0.00	3.53E-03	1.55E-02
CO2-e	117.10	(4)	1.87E+03	8.21E+03	8.21E+03	None	0.00	1.87E+03	8.206E+03

References
1. Vendor supplied factors
2. SO2 based on fuel sulfur content and AP-42 Table 1.4-2
3. H2SO4 based on 7.7% conversion of SO2 to SO3 and 100% of SO3 to H2SO4
4. GHG emissions from EPA "Mandatory Reporting of Greenhouse Gases" FR Vol. 74, No. 209, Part 98 (October 2009)

Facility C4GT LLC
Location Charles City Co.
Reg. No. 52588
Eng AMS

HAP from Dew Point Heater FGH-1
BTU Rating: 16.0 MMBtu/hr

	EF	Emissions	
Pollutant	lb/MMBtu	lb/hr	TPY
2-methylnapthalene	2.35E-08	3.76E-07	1.65E-06
3-methylchloranthrene	1.76E-09	2.82E-08	1.23E-07
7,12-Dimethylbenz(a)anthracene	1.57E-08	2.51E-07	1.10E-06
Acenaphthene	1.76E-09	2.82E-08	1.23E-07
Acenaphthylene	1.76E-09	2.82E-08	1.23E-07
Anthracene	2.35E-09	3.76E-08	1.65E-07
Benz(a)anthracene	1.76E-09	2.82E-08	1.23E-07
Benzene	2.06E-06	3.30E-05	1.44E-04
Benzo(a)pyrene	1.18E-09	1.89E-08	8.27E-08
Benzo(b)flouoranthene	1.76E-09	2.82E-08	1.23E-07
Benzo(g,h,l)perylene	1.18E-09	1.89E-08	8.27E-08
Benzo(k)fluoranthene	1.76E-09	2.82E-08	1.23E-07
Chrysene	1.76E-09	2.82E-08	1.23E-07
Dibenzo(ah)anthracene	1.18E-09	1.89E-08	8.27E-08
Dichlorobenzene	1.18E-06	1.89E-05	8.27E-05
Fluoranthene	2.94E-09	4.70E-08	2.06E-07
Fluorene	2.75E-09	4.40E-08	1.93E-07
Formaldehyde	7.35E-05	1.18E-03	5.15E-03
Hexane*	4.51E-06	7.22E-05	3.16E-04
Indeno(123-cd)pyrene	1.76E-09	2.82E-08	1.23E-07
Naphthalene	5.98E-07	9.57E-06	4.19E-05
Phenanathrene	1.67E-08	2.67E-07	1.17E-06
Pyrene	4.90E-09	7.84E-08	3.43E-07
Toluene	3.33E-06	5.33E-05	2.33E-04

METALS

Arsenic	1.96E-07	3.136E-06	1.37E-05
Beryllium	1.18E-08	1.888E-07	8.27E-07
cadmium	1.08E-06	1.73E-05	7.57E-05
chromium	1.37E-06	2.19E-05	9.6E-05
cobalt	8.24E-08	1.32E-06	5.77E-06
lead	4.90E-07	7.84E-06	3.43E-05
manganese	3.73E-07	5.97E-06	2.61E-05
mercury	2.55E-07	4.08E-06	1.79E-05
nickel	2.06E-06	3.30E-05	0.000144
selenium	2.35E-08	3.76E-07	1.65E-06

Lead factor from AP-42 Section 1.4
Other factors from AP-42 Tables 1.4-3 & 1.4-4
*Hexane factor from B 2588 external combustion factors, Ventura County APCD

Facility C4GT LLC
Location Charles City Co.
Reg. No. 52588
Eng AMS

Emergency Diesel Generator EG-1

2500	kW	3633	hp
453.59	g/lb	500	hrs/yr operation
7000	Btu/hp-hr	140	MMBtu/kgal
140	MMBtu/kgal	25.43	MMBtu/hr HHV

Pollutant	Basis	EF	unit	Emissions lb/hr	Emissions tons/yr
PM	(1)	0.15	g/hp-hr	1.20	0.30
PM_{10}	(1)	0.15	g/hp-hr	1.20	0.30
$PM_{2.5}$	(1)	0.15	g/hp-hr	1.20	0.30
CO	(1)	2.6	g/hp-hr	20.82	5.21
NOx	(1)	3.36	g/hp-hr	26.91	6.73
VOC	(1)	1.44	g/hp-hr	11.53	2.88
SO_2	(3)	1.21E-05	lb/hp-hr	0.04	0.01
H_2SO_4	(5)	9.30E-07	lb/hp-hr	3.38E-03	8.44E-04
CO_2	(4)	163.054	lb/MMBtu	4146.46	1036.62
CH_4	(4)	0.00661	lb/MMBtu	0.17	0.04
N_2O	(4)	0.0013	lb/MMBtu	0.03	0.01
CO_2e	(4)	163.614	lb/MMBtu	4160.69	1040.17

(1) PM, CO, and NOx+NMHC EF from NSPS Subpart IIII (Table 1 of 40 CFR 89.112). Assume 70% NOx (3.36 g/hp-hr) , 30% VOC (1.44 g/hp-

(2) PM10 and PM2.5 were estimated by multiplying the PM factor by 2 to account for condensable PM emissions

(3) SO2 based on AP-42 Table 3.4-1

(4) GHG EF from 40 CFR Part 98, Table C-1

(5) H_2SO_4 is based on a 5% conversion of SO_2 to SO_3 and 100% conversion of SO3 to H2SO4

Facility	C4GT LLC
Location	Charles City Co.
Reg. No.	52588
Eng	AMS

Emergency Diesel Generator EG-1 HAP Emissions

2500	kW	3633	hp
453.59	g/lb	500	hrs/yr operation
7000	Btu/hp-hr	135	MMBtu/kgal
135	MMBtu/kgal	25.43	MMBtu/hr HHV

Pollutant	EF	unit	Emissions lb/hr	Emissions tons/yr
acetaldehyde	2.52E-05	lb/MMBtu	6.41E-04	1.60E-04
acrolein	7.88E-06	lb/MMBtu	2.00E-04	5.01E-05
benzene	7.76E-04	lb/MMBtu	1.97E-02	4.93E-03
formaldehyde	7.89E-05	lb/MMBtu	2.01E-03	5.02E-04
lead	9.00E-06	lb/MMBtu	2.29E-04	5.72E-05
naphthalene (PAH)	1.30E-04	lb/MMBtu	3.31E-03	8.26E-04
toluene	2.81E-04	lb/MMBtu	7.15E-03	1.79E-03
xylene	1.93E-04	lb/MMBtu	4.91E-03	1.23E-03

Factors from AP-42 Table 3.4-3 & 3.4-4
Lead factor from AP-42 Table 1.3-10

Facility C4GT LLC
Location Charles City Co.
Reg. No. 52588
Eng AMS

Diesel Fire Water Pump (FWP-1)

315	bhp	234.9	kW
453.59	g/lb		
7000	Btu/hp-hr	500	hrs/yr operation
135	MMBtu/kgal	2.21	MMBtu/hr HHV

Pollutant	EF	unit	Emissions lb/hr	Emissions tons/yr
PM	0.15	g/hp-hr	0.10	0.0260
PM_{10}	0.15	g/hp-hr	0.10	0.0260
$PM_{2.5}$	0.15	g/hp-hr	0.10	0.0260
CO	2.6	g/hp-hr	1.81	0.4514
NOx + NMHC	3.0	g/hp-hr	2.08	0.5208
SO_2	0.00154	lb/MMBtu	0.003	0.0009
H_2SO_4	1.18E-04	lb/MMBtu	2.61E-04	6.52E-05
CO_2	163.054	lb/MMBtu	360.3487	90.087
CH_4	0.0066	lb/MMBtu	0.0146	0.004
N_2O	0.00132	lb/MMBtu	0.0029	0.001
CO_2e	163.613	lb/MMBtu	361.5852	90.396

PM, CO, and NOx/TOC EF from NSPS Subpart IIII, Table 4
SO_2 based on AP-42 Section 3.3, Table 3.3-1
GHG EF from 40 CFR Part 98, Table C-1
H_2SO_4 is based on a 5% conversion of SO_2 to SO_3 and 100% conversion of SO_3 to H_2SO_4

Facility	C4GT LLC
Location	Charles City Co.
Reg. No.	52588
Eng	AMS

Diesel Fire Water Pump FP-1 HAP Emissions

315	hp	500	hrs/yr operation
0.45359	kg/lb	135	MMBtu/kgal
7000	Btu/hp-hr		
135	MMBtu/kgal	2.21	MMBtu/hr HHV

			Emissions	
Pollutant	EF	unit	lb/hr	tons/yr
acetaldehyde	7.67E-04	lb/MMBtu	1.70E-03	4.24E-04
acrolein	9.25E-05	lb/MMBtu	2.04E-04	5.11E-05
benzene	9.33E-04	lb/MMBtu	2.06E-03	5.15E-04
formaldehyde	1.18E-03	lb/MMBtu	2.61E-03	6.52E-04
lead	9.00E-06	lb/MMBtu	1.99E-05	4.97E-06
naphthalene	8.48E-05	lb/MMBtu	1.87E-04	4.69E-05
toluene	4.09E-04	lb/MMBtu	9.04E-04	2.26E-04
xylene	2.85E-04	lb/MMBtu	6.30E-04	1.57E-04

Factors from AP-42 Tables 3.4-3 and 3.4-4
Lead factor from AP-42 Table 1.3-10

Facility C4GT LLC
Location Charles City Co.
Reg. No. 52588
Eng AMS

Cooling Tower with 18 cells

Water Flow Rate[1] (gpm)	Total Dissolved Solids (mg/L)	Liquid Drift Loss (%)	Drift Mass Flow Rate[3] (lb/hr)	Total PM Emission Rate [4, 5] (lb/hr)	(tpy)	Total PM10 Emission Rate[4, 5, 6] (lb/hr)	(tpy)	Total PM2.5 Emission Rate [4, 5, 7] (lb/hr)	(tpy)
348,500	6250	0.0005%	872.501	5.45E+00	2.39E+01	3.27E-02	1.43E-01	1.20E-03	5.25E-03

Footnotes
[1]Cooling Tower water flow rate is for all 18 cells combined
[2]Based on *Effects of Pathogenic and Toxic Material Transport Via Cooling Device Drift - Vol 1* Technical Report EPA 600 7-79-251a, November 1979.
[3]Drift mass flow rate (lb/hr) = Cooling Tower capacity (gpm) x Density of water (8.34 lb/gal) x 60 (min/hr) x Drift loss (%)
[4]Hourly PM/PM10/PM2.5 emission rate (lb/hr) = Drift mass flow rate (lb/hr) x TDS (mg/L)/1000000
[5]Annual PM/PM10/pm2.5 emission rate (ton/yr) = Hourly rate (lb/hr) x 8760 hrs/yr /2000 lb/ton
[6]Hourly PM10 emission rate (lb/hr) = 0.6% x PM rate
[7]Hourly PM2.5 emission rate (lb/hr) = 0.022% x PM rate

Facility	C4GT LLC
Location	Charles City Co.
Reg. No.	52588
Eng	AMS

ULSD Oil Tank for EG-1

3,000	gallon capacity		TANKS 4.0.9d
10	ft diameter		Emissions Report - Brief Format
22	ft length		Individual Summaries
29	turnovers/yr		
87,000	gallons/yr		
		VOC Losses(lbs)	
		Total Emissions	
Distillate fuel oil tank		2.28	lbs/yr

ULSD Oil Tank for FWP-1

400	gallon capacity		TANKS 4.0.9d
	ft diameter		Emissions Report - Brief Format
	ft length		Individual Summaries
22	turnovers/yr		
8,800	gallons/yr		
		VOC Losses(lbs)	
		Total Emissions	
Distillate fuel oil tank		0.26	lbs/yr

Facility	C4GT LLC
Location	Charles City Co.
Reg. No.	52588
Eng	AMS

Four Electical Circuit Breakers CB-1 through CB-4 combined

1900	lb of SF6/breaker
4	breakers
0.5%	leakage rate*
38	lb/yr leakage
0.019	tpy SF6
433.2	tpy CO2-e (@ 22,800 GWP)**

Leakage will be monitored by
gas density gauges on the breakers

Two Circuit Breakers CB-5 through 6 combined

30	lb of SF6/breaker
2	breakers
0.5%	leakage rate*
0.3	lb/yr leakage
0.00015	tpy SF6
3.42	tpy CO2-e (@ 22,800 GWP)**

Leakage will be monitored by
gas density gauges on the breakers

Total 436.62 tpy of CO2-e

*leakage rate estimate provided by manufacturer

** GWP from Table A-1 of Appendix A of 40 CFR Subpart 98

Facility	C4GT LLC
Location	Charles City Co.
Reg. No.	52588
Eng	AMS

Gas Analysis

Constituent	MW (g/g mole)	Quantity[a] (mole %)
Methane	16	99.00%
CO2	44	1.00%
TOTAL		100.0%

Note a -Estimated by C4GT

Gas density 41,300 lb/MMcf

Emissions Calculations

Equipment Type	Emission Factor (scf/hr/source)	Component Count	Fugitive CH_4 Emissions			Fugitive CO_2 Emissions			Total Fugitive CO_{2e} Emissions	
			lb/hr	tpy	CO_{2e} tpy	lb/hr	tpy	CO_{2e} tpy	lb/hr	tpy
Valves	0.027	400	0.44	1.93	48.35	0.00	0.02	0.02	11.04	48.37
Connectors	0.003	700	0.09	0.38	9.40	0.00	0.00	0.00	2.15	9.41
Pressure Relief Valves	0.04	20	0.03	0.14	3.58	0.00	0.00	0.00	0.82	3.58
TOTAL			0.56	2.45	61.34	0.01	0.02	0.02	14.01	61.36

Notes: 1 - Factors obtained from 40 CFR 98 Subpart W, Table W-1A. Flange and Sampling Connection emission factors were assumed to be similar to the Valve emission factor.

2 - 10% margin has been added to the count on the current plans since the design on the system is not complete.

3 - Assumed all valves 2" and greater are flanged.

4 - Includes Transco and ACP M&R yards, both gas turbines, both HRSG duct burners, auxiliary boiler, and gas piping for the balance of plant.

Facility C4GT LLC - GE7FA.02
Location Charles City Co.
Reg. No. 52588
Eng AMS

Totals	CT-1		CT-2		DB		Combined DB & Turbine		each turbine SU/SD*		EG-1		FWP-1		DPH 1		B-1		CLT		ST-1, ST-2		CB-1 through CB-6		FUG-1		Facility	
	Turbine		Turbine		each Duct Burner		one T+DB		start up/shut down		Em Generator		Fire Water Pump		Fuel Gas Htr		Aux Boiler		Cooling Tower		two oil tanks		Circuit Breakers		Fugitive CO2e		Totals	
pollutant	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy		tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy		tpy		tpy	lb/hr	tpy
PM	10.88	47.64	10.88	47.64	5.15	22.56	16.03	70.20	--	1.80	1.20	0.30	0.10	0.03	0.11	0.49	0.74	3.22	5.45E+00	2.39E+01	--	--	--	--			39.66	168.31
PM10	12.18	53.35	12.18	53.35	5.15	22.56	17.33	75.90	--	1.80	1.20	0.30	0.10	0.03	0.11	0.49	0.74	3.22	3.27E-02	1.43E-01	--	--	--	--			36.84	155.99
PM2.5	12.18	53.35	12.18	53.35	5.15	22.56	17.33	75.90	--	1.80	1.20	0.30	0.10	0.03	0.11	0.49	0.74	3.22	1.20E-03	5.25E-03	--	--	--	--			36.81	155.85
CO	8.09	35.43	8.09	35.43	6.10	26.70	14.18	62.13	--	38.45	20.82	5.21	1.81	0.45	0.59	2.59	3.89	17.02	--	--	--	--	--	--			55.47	222.62
NOx	26.57	116.40	26.57	116.40	2.62	11.49	29.20	127.88	--	17.30	26.91	6.73	2.08	0.52	0.18	0.77	1.16	5.06	--	--	--	--	--	--			88.72	295.61
SO2	3.97	17.39	3.97	17.39	0.38	1.66	4.35	19.05	--	0.14	0.04	0.01	0.00	0.00	0.02	0.08	0.12	0.54	--	--	--	--	--	--			8.89	38.74
VOC	3.24	10.68	3.24	10.68	3.90	17.06	7.13	31.25	--	10.03	11.53	2.88			0.08	0.35	0.53	2.30	--	--	1.45E-07	0.00127	--	--			26.41	86.16
H_2SO4	2.44	10.68	2.44	10.68	0.23	1.03	2.67	11.70	--	--	3.38E-03	8.44E-04	2.61E-04	6.52E-05	0.00	0.01	9.46E-03	4.14E-02	--	--	--	--	--	--			5.36	23.46
CO_2	4.07E+05	1.78E+06	4.07E+05	1.78E+06	5.56E+04	2.43E+05	4.63E+05	2.03E+06	--	--	4.15E+03	1.04E+03	3.60E+02	9.01E+01	1.87E+03	8.20E+03	1.23E+04	5.38E+04	--	--	--	--	--	--	5.60E-01	2.48E-02	9.44E+05	4.12E+06
CH_4	7.68E+00	3.36E+01	7.68E+00	3.36E+01	1.05E+00	4.59E+00	8.72E+00	3.82E+01	--	--	1.68E-01	4.20E-02	1.46E-02	3.65E-03	3.53E-02	1.55E-01	2.31E-01	1.01E+00	--	--	--	--	--	--	5.66E-03	2.45E+00	1.79E+01	8.01E+01
N2O	7.68E-01	3.36E+00	7.68E-01	3.36E+00	1.05E-01	4.59E-01	8.72E-01	3.82E+00	--	--	3.36E-02	8.41E-03	2.92E-03	7.31E-04	3.53E-03	1.55E-02	2.31E-02	1.01E-01	--	--	--	--	--	--			1.81E+00	7.77E+00
SF6	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	1.92E-02			--	1.92E-02
CO2-e	4.08E+05	1.79E+06	4.08E+05	1.79E+06	5.56E+04	2.44E+05	4.63E+05	2.030E+06	--	--	4.16E+03	1.04E+03	3.62E+02	9.04E+01	1.87E+03	8.21E+03	1.23E+04	5.39E+04	--	--	--	--	--	4.37E+02	1.40E+01	6.14E+01	8.90E+05	4122773

***SU/SD emissions are only included in the total if they represent the worst case annual operating scenario [((turbines + duct burner) x 8492 hrs/yr + SU/SD) vs. ((duct burner + turbine) x 8760 hrs/yr without SU/SD)]**

Facility C4GT LLC - GE7FA.02
Location Charles City Co.
Reg. No. 52588
Eng AMS

Total HAP	Turbines w/duct firing		Auxilliary Boiler		Dew Point Heater		Emergency Fire Water Pump		Em. Gen		Totals for all units		Exemption Levels		Exempt ?	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	hourly	annual
1,3-Butadiene	2.99E-03	1.31E-02									2.99E-03	1.31E-02	1.452	3.19	Yes	Yes
2-methylnaphthalene	2.23E-05	9.78E-05	2.47E-06	1.08E-05	3.76E-07	1.65E-06					2.52E-05	1.10E-04			Yes	Yes
3-methylchloranthrene	1.67E-06	7.32E-06	1.85E-07	8.09E-07	2.82E-08	1.23E-07					1.89E-06	8.26E-06			Yes	Yes
7,12-Dimethylbenz(a)anthracene	1.49E-05	6.53E-05	1.65E-06	7.22E-06	2.51E-07	1.10E-06					1.68E-05	7.37E-05			Yes	Yes
Acenaphthene	1.67E-06	7.32E-06	1.85E-07	8.09E-07	2.82E-08	1.23E-07					1.89E-06	8.26E-06			Yes	Yes
Acenaphthylene	1.67E-06	7.32E-06	1.85E-07	8.09E-07	2.82E-08	1.23E-07					1.89E-06	8.26E-06			Yes	Yes
Acetaldehyde	2.79E-01	1.22E+00					1.70E-03	4.24E-04	6.41E-04	1.60E-04	2.81E-01	1.22E+00	8.91	26.1	Yes	Yes
Acrolein	4.46E-02	1.95E-01					2.04E-04	5.11E-05	2.00E-04	5.01E-05	4.50E-02	1.95E-01	0.02277	0.03335	No	No
Anthracene	2.23E-06	9.78E-06	2.47E-07	1.08E-06	3.76E-08	1.65E-07					2.52E-06	1.10E-05			Yes	Yes
Benz(a)anthracene	1.67E-06	7.32E-06	1.85E-07	8.09E-07	2.82E-08	1.23E-07					1.89E-06	8.26E-06			Yes	Yes
Benzene	8.55E-02	3.75E-01	2.16E-04	9.47E-04	3.30E-05	1.44E-04	2.06E-03	5.15E-04	1.97E-02	4.93E-03	1.08E-01	3.81E-01	2.112	4.64	Yes	Yes
Benzo(a)pyrene	1.12E-06	4.91E-06	1.24E-07	5.43E-07	1.89E-08	8.27E-08					1.26E-06	5.54E-06			Yes	Yes
Benzo(b)flouoranthene	1.67E-06	7.32E-06	1.85E-07	8.09E-07	2.82E-08	1.23E-07					1.89E-06	8.26E-06			Yes	Yes
Benzo(g,h,l)perylene	1.12E-06	4.91E-06	1.24E-07	5.43E-07	1.89E-08	8.27E-08					1.26E-06	5.54E-06			Yes	Yes
Benzo(k)fluoranthene	1.67E-06	7.32E-06	1.85E-07	8.09E-07	2.82E-08	1.23E-07					1.89E-06	8.26E-06			Yes	Yes
Chrysene	1.67E-06	7.32E-06	1.85E-07	8.09E-07	2.82E-08	1.23E-07					1.89E-06	8.26E-06			Yes	Yes
Dibenzo(ah)anthracene	1.12E-06	4.91E-06	1.24E-07	5.43E-07	1.89E-08	8.27E-08					1.26E-06	5.54E-06			Yes	Yes
Dichlorobenzene	1.12E-03	4.91E-03	1.24E-04	5.43E-04	1.89E-05	8.27E-05					1.26E-03	5.54E-03	21.813	65.395	Yes	Yes
Ethylbenzene	2.23E-01	9.76E-01									2.23E-01	9.76E-01	17.919	62.93	Yes	Yes
Fluoranthene	2.79E-06	1.22E-05	3.09E-07	1.35E-06	4.70E-08	2.06E-07					3.15E-06	1.38E-05			Yes	Yes
Fluorene	2.61E-06	1.14E-05	2.89E-07	1.26E-06	4.40E-08	1.93E-07					2.95E-06	1.29E-05			Yes	Yes
Formaldehyde	1.60E+00	7.02E+00	7.72E-03	3.38E-02	1.18E-03	5.15E-03	2.61E-03	6.52E-04	2.01E-03	5.02E-04	1.62E+00	7.06E+00	0.0825	0.174	No	No
Hexane	1.67E+00	7.32E+00	1.34E-04	5.89E-04	7.22E-05	3.16E-04					1.67E+00	7.33E+00	11.616	25.52	Yes	Yes
Indeno(123-cd)pyrene	1.67E-06	7.32E-06	1.85E-07	8.09E-07	2.82E-08	1.23E-07					1.89E-06	8.26E-06			Yes	Yes
Naphthalene	9.62E-03	4.21E-02	6.28E-05	2.75E-04	9.57E-06	4.19E-05	1.87E-04	4.69E-05	3.31E-03	8.26E-04	1.32E-02	4.33E-02	2.607	7.54	Yes	Yes
Phenanathrene	1.59E-05	6.95E-05	1.75E-06	7.68E-06	2.67E-07	1.17E-06					1.79E-05	7.83E-05			Yes	Yes
Propylene Oxide	2.02E-01	8.85E-01									2.02E-01	8.85E-01	3.168	6.96	Yes	Yes
Pyrene	4.66E-06	2.04E-05	5.15E-07	2.25E-06	7.84E-08	3.43E-07					5.25E-06	2.30E-05			Yes	Yes
Toluene	9.08E-01	3.98E+00	3.50E-04	1.53E-03	5.33E-05	2.33E-04	9.04E-04	2.26E-04	7.15E-03	1.79E-03	9.17E-01	3.98E+00	18.645	54.665	Yes	Yes
Xylene	4.46E-01	1.95E+00					6.30E-04	1.57E-04	4.91E-03	1.23E-03	4.51E-01	1.95E+00	21.483	62.93	Yes	Yes
															Yes	Yes
Arsenic	1.86E-04	8.16E-04	2.06E-05	9.01E-05	3.14E-06	1.37E-05					2.10E-04	9.20E-04	0.0132	0.029	Yes	Yes
Beryllium	1.12E-05	4.91E-05	1.24E-06	5.43E-06	1.89E-07	8.27E-07					1.26E-05	5.54E-05	0.000132	0.00029	Yes	Yes
cadmium	1.03E-03	4.49E-03	1.13E-04	4.97E-04	1.73E-05	7.57E-05					1.16E-03	5.07E-03	0.033	0.00725	Yes	Yes
chromium	1.30E-03	5.70E-03	1.44E-04	6.30E-04	2.19E-05	9.60E-05					1.47E-03	6.43E-03	0.0033	0.00725	Yes	Yes
cobalt	7.83E-05	3.43E-04	8.65E-06	3.79E-05	1.32E-06	5.77E-06					8.83E-05	3.87E-04	0.0033	0.00725	Yes	Yes
lead	3.88E-03	1.70E-02	5.15E-05	2.25E-04	7.84E-06	3.43E-05	1.99E-05	4.97E-06	2.29E-04	5.72E-05	4.19E-03	1.73E-02	0.0099	0.02175	Yes	Yes
manganese	3.54E-04	1.55E-03	3.92E-05	1.72E-04	5.97E-06	2.61E-05					4.00E-04	1.75E-03	0.33	0.725	Yes	Yes
mercury	2.42E-04	1.06E-03	2.68E-05	1.17E-04	4.08E-06	1.79E-05					2.73E-04	1.20E-03	0.0033	0.00725	Yes	Yes
nickel	1.96E-03	8.57E-03	2.16E-04	9.47E-04	3.30E-05	1.44E-04					2.21E-03	9.66E-03	0.0066	0.0145	Yes	Yes
selenium	2.23E-05	9.78E-05	2.47E-06	1.08E-05	3.76E-07	1.65E-06					2.52E-05	1.10E-04	0.0132	0.029	Yes	Yes

Facility C4GT LLC - GE7FA.02
Location Charles City Co.
Reg. No. 52588
Eng AMS

Totals	CT-1		CT-2		DB		Combined DB & Turbine		each turbine SU/SD*		Worst case annual CTx2	EG-1	
	Turbine		Turbine		each Duct Burner		one T+DB		start up/shut down		TPY	Em Generator	
pollutant	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy		tpy		lb/hr	tpy
PM	15.27	66.88	15.27	66.88	10.51	46.04	25.78	112.92	--	1.18	225.84	1.20	0.30
PM10	13.63	59.70	13.63	59.70	10.51	46.04	24.14	105.74	--	1.18	211.49	1.20	0.30
PM2.5	13.63	59.70	13.63	59.70	10.51	46.04	24.14	105.74	--	1.18	211.49	1.20	0.30
CO	12.85	56.30	12.85	56.30	3.22	14.08	16.07	70.38	--	66.69	268.18	20.82	5.21
NOx	23.42	102.57	23.42	102.57	5.77	25.26	29.18	127.82	--	18.93	282.69	26.91	6.73
SO2	3.56	15.61	3.56	15.61	0.84	3.69	4.41	19.30	--	0.00	38.60	0.04	0.01
VOC	4.10	17.96	4.10	17.96	6.13	26.85	10.23	44.82	--	11.14	108.10	11.53	2.88
H2SO4	2.19	9.61	2.19	9.61	0.51	2.21	2.70	11.82	--	--		3.38E-03	8.44E-04
CO_2	3.65E+05	1.60E+06	3.65E+05	1.60E+06	1.16E+05	5.08E+05	4.80E+05	2.10E+06	--	--		4.15E+03	1.04E+03
CH_4	6.87E+00	3.01E+01	6.87E+00	3.01E+01	2.18E+00	9.57E+00	9.05E+00	3.97E+01	--	--		1.68E-01	4.20E-02
N2O	6.87E-01	3.01E+00	6.87E-01	3.01E+00	2.18E-01	9.57E-01	9.05E-01	3.97E+00	--	--		3.36E-02	8.41E-03
SF6	--	--	--	--	--	--	--	--	--	--		--	--
CO2-e	3.65E+05	1.60E+06	3.65E+05	1.60E+06	1.16E+05	5.08E+05	4.81E+05	2.11E+06	--	--		4.16E+03	1.04E+03

Totals	FWP-1		DPH-1		B-1		CLT		ST-1, ST-2		CB-1 through CB-6		FUG-1		Facility	
	Fire Water Pump		Fuel Gas Htr		Aux Boiler		Cooling Tower		two oil tanks		Circuit Breakers		Fugitive CO2e		Totals	
pollutant	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy		tpy		tpy	lb/hr	tpy
PM	0.10	0.03	0.11	0.49	0.74	3.22	5.45E+00	2.39E+01	--	--	--	--			59.17	253.76
PM10	0.10	0.03	0.11	0.49	0.74	3.22	3.27E-02	1.43E-01	--	--	--	--			50.47	215.67
PM2.5	0.10	0.03	0.11	0.49	0.74	3.22	1.20E-03	5.25E-03	--	--	--	--			50.44	215.53
CO	1.81	0.45	0.59	2.59	3.89	17.02	--	--	--	--	--	--			59.24	293.45
NOx	2.08	0.52	0.18	0.77	1.16	5.06	--	--	--	--	--	--			88.69	295.76
SO2	0.00	0.00	0.02	0.08	0.12	0.54	--	--	--	--	--	--			9.00	39.24
VOC			0.08	0.35	0.53	2.30	--	--	1.45E-07	0.00127	--	--			32.60	113.64
H2SO4	2.61E-04	6.52E-05	0.00	0.01	9.46E-03	4.14E-02	--	--	--	--	--	--			5.41	23.69
CO_2	3.60E+02	9.01E+01	1.87E+03	8.20E+03	1.23E+04	5.38E+04	--	--	--	--	--	--	5.60E-01	2.48E-02	9.79E+05	4.27E+06
CH_4	1.46E-02	3.65E-03	3.53E-02	1.55E-01	2.31E-01	1.01E+00	--	--	--	--	--	--	5.66E-03	2.45E+00	1.86E+01	8.30E+01
N2O	2.92E-03	7.31E-04	3.53E-03	1.55E-02	2.31E-02	1.01E-01	--	--	--	--	--	--			1.87E+00	8.06E+00
SF6	--	--	--	--	--	--	--	--	--	--	--	1.92E-02			--	1.92E-02
CO2-e	3.62E+02	9.04E+01	1.87E+03	8.21E+03	1.23E+04	5.39E+04	--	--	--	--	--	4.37E+02	1.40E+01	6.14E+01	9.81E+05	4276448

***SU/SD emissions are only included in the total if they represent the worst case annual operating scenario [((turbines + duct burner) x 8389 hrs/yr + SU/SD) vs. ((duct burner + turbine) x 8760 hrs/yr without SU/SD)]**

Facility C4GT LLC - Siemens SGT6-8000H
Location Charles City Co.
Reg. No. 52588
Eng AMS

Total HAP	Turbines w/duct firing		Auxilliary Boiler		Dew Point Heater		Emergency Fire Water Pump		Em. Gen		Totals for all units		Exemption Levels		Exempt ?	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	hourly	annual
1,3-Butadiene	2.68E-03	1.17E-02									2.68E-03	1.17E-02	1.452	3.19	Yes	Yes
2-methylnaphthalene	2.12E-05	9.28E-05	2.47E-06	1.08E-05	3.76E-07	1.65E-06					2.40E-05	1.05E-04			Yes	Yes
3-methylchloranthrene	1.59E-06	6.95E-06	1.85E-07	8.09E-07	2.82E-08	1.23E-07					1.80E-06	7.88E-06			Yes	Yes
7,12-Dimethylbenz(a)anthracene	1.42E-05	6.20E-05	1.65E-06	7.22E-06	2.51E-07	1.10E-06					1.61E-05	7.03E-05			Yes	Yes
Acenaphthene	1.59E-06	6.95E-06	1.85E-07	8.09E-07	2.82E-08	1.23E-07					1.80E-06	7.88E-06			Yes	Yes
Acenaphthylene	1.67E-06	7.32E-06	1.85E-07	8.09E-07	2.82E-08	1.23E-07					1.89E-06	8.26E-06			Yes	Yes
Acetaldehyde	2.49E-01	1.09E+00					1.70E-03	4.24E-04	6.41E-04	1.60E-04	2.52E-01	1.09E+00	8.91	26.1	Yes	Yes
Acrolein	3.99E-02	1.75E-01					2.04E-04	5.11E-05	2.00E-04	5.01E-05	4.03E-02	1.75E-01	0.02277	0.03335	No	No
Anthracene	2.12E-06	9.28E-06	2.47E-07	1.08E-06	3.76E-08	1.65E-07					2.40E-06	1.05E-05			Yes	Yes
Benz(a)anthracene	1.59E-06	6.95E-06	1.85E-07	8.09E-07	2.82E-08	1.23E-07					1.80E-06	7.88E-06			Yes	Yes
Benzene	7.66E-02	3.36E-01	2.16E-04	9.47E-04	3.30E-05	1.44E-04	2.06E-03	5.15E-04	1.97E-02	4.93E-03	9.87E-02	3.42E-01	2.112	4.64	Yes	Yes
Benzo(a)pyrene	1.06E-06	4.66E-06	1.24E-07	5.43E-07	1.89E-08	8.27E-08					1.21E-06	5.29E-06			Yes	Yes
Benzo(b)flouoranthene	1.59E-06	6.95E-06	1.85E-07	8.09E-07	2.82E-08	1.23E-07					1.80E-06	7.88E-06			Yes	Yes
Benzo(g,h,l)perylene	1.06E-06	4.66E-06	1.24E-07	5.43E-07	1.89E-08	8.27E-08					1.21E-06	5.29E-06			Yes	Yes
Benzo(k)fluoranthene	1.59E-06	6.95E-06	1.85E-07	8.09E-07	2.82E-08	1.23E-07					1.80E-06	7.88E-06			Yes	Yes
Chrysene	1.59E-06	6.95E-06	1.85E-07	8.09E-07	2.82E-08	1.23E-07					1.80E-06	7.88E-06			Yes	Yes
Dibenzo(ah)anthracene	1.06E-06	4.66E-06	1.24E-07	5.43E-07	1.89E-08	8.27E-08					1.21E-06	5.29E-06			Yes	Yes
Dichlorobenzene	1.06E-03	4.66E-03	1.24E-04	5.43E-04	1.89E-05	8.27E-05					1.21E-03	5.29E-03	21.813	65.395	Yes	Yes
Ethylbenzene	1.99E-01	8.73E-01									1.99E-01	8.73E-01	17.919	62.93	Yes	Yes
Fluoranthene	2.65E-06	1.16E-05	3.09E-07	1.35E-06	4.70E-08	2.06E-07					3.01E-06	1.32E-05			Yes	Yes
Fluorene	2.48E-06	1.09E-05	2.89E-07	1.26E-06	4.40E-08	1.93E-07					2.81E-06	1.23E-05			Yes	Yes
Formaldehyde	1.56E+00	6.84E+00	7.72E-03	3.38E-02	1.18E-03	5.15E-03	2.61E-03	6.52E-04	2.01E-03	5.02E-04	1.58E+00	6.88E+00	0.0825	0.174	No	No
Hexane	1.59E+00	6.95E+00	1.34E-04	5.89E-04	7.22E-05	3.16E-04					1.59E+00	6.95E+00	11.616	25.52	Yes	Yes
Indeno(123-cd)pyrene	1.59E-06	6.95E-06	1.85E-07	8.09E-07	2.82E-08	1.23E-07					1.80E-06	7.88E-06			Yes	Yes
Naphthalene	8.64E-03	3.78E-02	6.28E-05	2.75E-04	9.57E-06	4.19E-05	1.87E-04	4.69E-05	3.31E-03	8.26E-04	1.22E-02	3.90E-02	2.607	7.54	Yes	Yes
Phenanathrene	1.59E-05	6.95E-05	1.75E-06	7.68E-06	2.67E-07	1.17E-06					1.79E-05	7.83E-05			Yes	Yes
Propylene Oxide	1.81E-01	7.92E-01									1.81E-01	7.92E-01	3.168	6.96	Yes	Yes
Pyrene	4.42E-06	1.94E-05	5.15E-07	2.25E-06	7.84E-08	3.43E-07					5.01E-06	2.19E-05			Yes	Yes
Toluene	8.13E-01	3.56E+00	3.50E-04	1.53E-03	5.33E-05	2.33E-04	9.04E-04	2.26E-04	7.15E-03	1.79E-03	8.22E-01	3.57E+00	18.645	54.665	Yes	Yes
Xylene	3.99E-01	1.75E+00					6.30E-04	1.57E-04	4.91E-03	1.23E-03	4.04E-01	1.75E+00	21.483	62.93	Yes	Yes
Arsenic	3.88E-04	1.70E-03	2.06E-05	9.01E-05	3.14E-06	1.37E-05					4.12E-04	1.81E-03	0.0132	0.029	Yes	Yes
Beryllium	2.34E-05	1.02E-04	1.24E-06	5.43E-06	1.89E-07	8.27E-07					2.48E-05	1.09E-04	0.000132	0.00029	Yes	Yes
cadmium	2.14E-03	9.37E-03	1.13E-04	4.97E-04	1.73E-05	7.57E-05					2.27E-03	9.95E-03	0.033	0.00725	Yes	No
chromium	2.71E-03	1.19E-02	1.44E-04	6.30E-04	2.19E-05	9.60E-05					2.88E-03	1.26E-02	0.0033	0.00725	Yes	No
cobalt	1.63E-04	7.15E-04	8.65E-06	3.79E-05	1.32E-06	5.77E-06					1.73E-04	7.59E-04	0.0033	0.00725	Yes	Yes
lead	4.03E-03	1.76E-02	5.15E-05	2.25E-04	7.84E-06	3.43E-05	1.99E-05	4.97E-06	2.29E-04	5.72E-05	4.33E-03	1.80E-02	0.0099	0.02175	Yes	Yes
manganese	7.39E-04	3.24E-03	3.92E-05	1.72E-04	5.97E-06	2.61E-05					7.84E-04	3.44E-03	0.33	0.725	Yes	Yes
mercury	5.05E-04	2.21E-03	2.68E-05	1.17E-04	4.08E-06	1.79E-05					5.36E-04	2.35E-03	0.0033	0.00725	Yes	Yes
nickel	4.08E-03	1.79E-02	2.16E-04	9.47E-04	3.30E-05	1.44E-04					4.33E-03	1.90E-02	0.0066	0.0145	Yes	No
selenium	4.66E-05	2.04E-04	2.47E-06	1.08E-05	3.76E-07	1.65E-06					4.94E-05	2.16E-04	0.0132	0.029	Yes	Yes

Facility C4GT LLC - GE7FA.02
Location Charles City Co.
Reg. No. 52588
Eng AMS

This permit action is for a new natural gas-fired power station

Pollutant	Potential to Emit* (TPY)	PSD Major?	PSD Significance Rate (TPY)**	PSD Required?
PM	168.31	Yes	15	Yes
PM_{10}	155.99	Yes	15	Yes
$PM_{2.5}$	155.85	Yes	10	Yes
CO	222.62	Yes	100	Yes
NO_x	295.61	Yes	40	Yes
SO_2	38.74	No	40	No
VOC	86.16	No	40	Yes
CO_2e	4,118,019.73	Yes	75,000	Yes
Lead	1.73E-02	No	0.6	No
H_2SO_4	23.46	No	7	Yes

*Potential to emit for Article8 permitting is based on proposed permit limitations.

**If PSD is triggered for any regulated pollutant, then any other pollutant which exceeds the PSD Significance Rate also triggers PSD permitting.

Pollutant	Potential to Emit (TPY)	Exemption Rate (TPY)	Article 6 Permitting?
PM_{10}	155.99	15	Yes
$PM_{2.5}$	155.85	10	Yes
CO	1267.77	100	Yes
NO_x	3210.15	40	Yes
SO_2	41.61	40	Yes
VOC	65.15	25	Yes
Lead	1.73E-02	0.6	No
H_2SO_4	23.46	6	Yes

Potential to emit for Article 6 permitting is based on uncontrolled emissions at 8760 hours/year (or 500 for emergency generators).

When pollutants are subject to Article 8 permitting and Article 6 permitting, Article 8 permitting requirements prevail.

Facility C4GT LLC - GE7FA.02
Location Charles City Co.
Reg. No. 52588
Eng AMS

This permit action is for a new natural gas-fired power station

Pollutant	Potential to Emit (TPY)	PSD Major?	PSD Significance Rate (TPY)*	PSD Required?
PM	253.76	Yes	15	Yes
PM_{10}	215.67	Yes	15	Yes
$PM_{2.5}$	215.53	Yes	10	Yes
NO_x	293.45	Yes	40	Yes
CO	295.76	Yes	100	Yes
SO_2	39.24	No	40	No
VOC	113.64	Yes	40	Yes
CO_2e	4,276,447.98	Yes	75,000	Yes
Lead	0.02	No	0.6	No
H_2SO_4	82.98	No	7	Yes

*If PSD is triggered for any regulated pollutant, then any other pollutant which exceeds the PSD Significance Rate also triggers PSD permitting.

Pollutant	Potential to Emit (TPY)	Exemption Rate (TPY)	Article 6 Permitting?
PM_{10}	215.67	15	Yes
$PM_{2.5}$	215.53	10	Yes
NO_x	293.45	40	Yes
CO	295.76	100	Yes
SO_2	39.24	40	No
VOC	113.64	25	Yes
Lead	1.73E-02	0.6	No
H_2SO_4	23.46	6	Yes

When pollutants are subject to Article 8 permitting and Article 6 permitting, Article 8 permitting requirements prevail.

Appendix B

Modeling Memo

MEMORANDUM

DEPARTMENT OF ENVIRONMENTAL QUALITY
Office of Air Quality Assessments

629 East Main Street, Richmond, VA 23219
8th Floor **804/698-4000**

To: James Kyle, Air Permit Manager (PRO)

From: Mike Kiss, Manager - Office of Air Quality Assessments (AQA)

Date: May 8, 2017

Subject: Technical Review of the PSD Air Quality Analyses – C4GT, LLC

Copies: Bobby Lute

I. Project Background

C4GT, LLC (C4GT) is proposing to construct and operate a natural gas-fired electric generating facility in Charles City County, Virginia, approximately 16 miles southeast of Richmond along State Route 106, approximately 2,000 feet north and west of the intersection of State Route 685. The proposed new facility, referred to as the C4GT Project, will consist of two identical natural gas-fired only combined-cycle turbines, each with its own duct-fired heat recovery steam generator (HRSG), one reheat condensing steam turbine generator, an 18-cell mechanical draft evaporative cooling tower, a natural gas-fired only auxiliary boiler, a natural gas-fired only fuel heater, a diesel-fired emergency generator and fire water pump, two distillate fuel oil storage tanks, and circuit breakers. C4GT has proposed the installation of either General Electric (7HA.02) or Siemens (SGT6-8000H) combustion turbines. The approximate generating capacity for the facility with the General Electric turbines is 1,060 megawatts (MW) and with the Siemens turbines is 1,085 MW.

The proposed facility meets the definition of major source under 9 VAC 5 Chapter 80, Article 8 (Prevention of Significant Deterioration (PSD)) of the Commonwealth of Virginia Regulations for the Control and Abatement of Air Pollution because it is a fossil-fuel-fired steam electric plant of more than 250 MMBtu/hr heat input capacity and has the potential to emit 100 tons per year (TPY) or more of a regulated pollutant. Also, the proposed facility has the potential to emit greenhouse gas (GHG) emissions equal to or greater than 75,000 TPY carbon dioxide equivalent (CO_2e). The pollutants subject to PSD review are nitrogen oxides (NO_X), particulate matter having an aerodynamic diameter equal to or less than 10 microns (PM-10), particulate matter having an aerodynamic diameter equal to or less than 2.5 microns (PM-2.5), carbon monoxide (CO), volatile organic compounds (VOC), sulfuric acid mist, and greenhouse gases (GHGs). As a result, PSD regulations require an air quality analysis be performed that demonstrates that the projected air emissions from the proposed facility will neither cause or significantly contribute to a violation of any applicable National Ambient Air Quality Standard (NAAQS) or PSD increment. In addition, PSD regulations require that additional impact analyses for soil, vegetation, growth and a visibility be conducted.

An analysis of the project's impact on air quality and air quality related values (AQRVs) in any affected Class I area may also be required, contingent upon input from the Federal Land Managers (FLMs). The United States Forest Service (USFS), the United States Fish and Wildlife Service (FWS), and the National Park Service (NPS) each stated in a separate e-mail dated May 16, 2016 that an AQRV analysis was not required since the project is not expected to show any significant additional impacts to AQRVs. Therefore, only a Class I area analysis to assess compliance with the Class I PSD increments is required.

The following is a summary of the AQA's review of the required air quality analyses for the C4GT Project for both Class I and Class II PSD areas. The worst-case impacts from all operating loads, including startup and shutdown operations, are presented in this memorandum.

II. Modeling Methodology

The Class I and Class II air quality modeling analyses conform to 40 CFR Part 51, Appendix W - Guideline on Air Quality Models and were performed in accordance with their respective approved modeling methodology. The air quality model used for both Class I and Class II area analyses was the most recent version of the AERMOD modeling system (Version 16216r). The AERMOD modeling system is the preferred EPA-approved regulatory model for near-field applications and is also contained in Appendix W of 40 CFR Part 51. AERMOD was also used as a preliminary screening model to determine the need for more detailed PSD increment modeling in the Class I area.

Additional details on the modeling methodology can be found in the applicable sections of C4GT's revised air permit application submittals dated April 2017.

III. Modeling Results

A. Class II Area - Preliminary Modeling Analysis

A preliminary modeling analysis for criteria pollutants was conducted in accordance with PSD regulations to predict the maximum ambient air impacts. The preliminary analysis modeled emissions from the proposed facility only to determine whether or not the impacts were above the applicable significant impact levels (SILs). For those pollutants for which maximum predicted impacts were less than the SIL, no further analyses was required (i.e., predicted maximum impacts less than SILs are considered insignificant and of no further concern). For impacts predicted to be equal to or greater than the SIL, a more refined air quality modeling analysis (i.e., full impact or cumulative impact analysis) is required to assess compliance with the NAAQS and PSD increment.

The emissions associated with nine (9) representative operating loads were modeled, as well as startup/shutdown emissions, for both the General Electric and the Siemens turbine options. Tables 1and 2 below show the maximum predicted ambient air concentrations for the General Electric and Siemens turbine options, respectively.

Table 1
Class II Preliminary Modeling Analysis Results vs. Significant Impact Levels
General Electric Turbines

Pollutant	Averaging Period	Maximum Predicted Concentration From Proposed Facility (µg/m^3)	Class II Significant Impact Level (µg/m^3)
CO	1-hour	625.05	2,000
	8-hour	62.05	500
NO_2	1-hour	199.88	7.5
	Annual	0.62	1
PM-10	24-hour	3.24	5
	Annual	0.23	1

Table 2
Class II Preliminary Modeling Analysis Results vs. Significant Impact Levels
Siemens Turbines

Pollutant	Averaging Period	Maximum Predicted Concentration From Proposed Facility (µg/m^3)	Class II Significant Impact Level (µg/m^3)
CO	1-hour	529.23	2,000
	8-hour	23.31	500
NO_2	1-hour	56.25	7.5
	Annual	0.85	1
PM-10	24-hour	2.37	5
	Annual	0.28	1

The modeling results for CO (1-hour and 8-hour averaging periods), NO_2 (annual averaging period), and PM-10 (24-hour and annual averaging periods) were less than the applicable SILs. Therefore, a full impact analysis for these pollutants and averaging periods was not required. In addition, the project's air quality impact, when added to existing background air quality, would not alter the current attainment status for any of these pollutants.

The proposed facility's increment consumption for NO_2 (annual averaging period) and PM-10 (24-hour and annual averaging period) is also not expected to cause or contribute to any increment violation. However, a full impact analysis for NO_2 (1-hour averaging period) was conducted because the preliminary modeling analysis results exceeded the applicable SIL. Additionally, a full impact analysis was conducted for PM-2.5 (24-hour and annual averaging periods) because the provisions of the PM-2.5 SILs in 40 CFR 51.166(k)(2) and 52.21(k)(2) were vacated in January 2013 and the DEQ does not currently have state-specific SILs for the purpose of excluding a project from performing a full impact analysis.

B. Class II Area – Cumulative Impact Modeling Analysis

The cumulative impact analysis consisted of separate analyses to assess compliance with the NAAQS for NO_2 and PM-2.5 and the Class II PSD increment for PM-2.5 for the applicable averaging periods. No PSD increment analysis was required for NO_2 (1-hour averaging period) because EPA has not promulgated a Class II PSD increment for this pollutant and averaging period.

It is important to note that the cumulative impact modeling results (both NAAQS and PSD increment) can sometimes be less than the "source only" modeling results in Tables 1 and 2 of this memorandum. This is due to the fact that source only modeling uses the <u>maximum</u> concentration to determine significance, whereas the cumulative modeling results reflect the form of the air quality standard. For example, the following criteria must be met to attain the NAAQS:

- NO_2 (1-hour) - To attain this standard, the 3-year average of the 98th percentile of the daily maximum 1-hour average at each monitor within an area must not exceed the standard.
- PM-2.5 (24-hour) - To attain this standard, the 3-year average of the 98th percentile of 24-hour concentrations at each population-oriented monitor within an area must not exceed the standard.
- PM-2.5 (annual) - To attain this standard, the 3-year average of the weighted annual mean PM-2.5 concentrations from single or multiple community-oriented monitors must not exceed the standard.

NAAQS Analysis

The NAAQS analysis included emissions from the proposed source, emissions from existing sources from Virginia, and representative ambient background concentrations of

NO_2 and PM-2.5. The results of the analysis are presented in Tables 3 and 4 for the General Electric and Siemens turbine options, respectively, and demonstrate compliance with the applicable NAAQS.

Table 3
NAAQS Modeling - Cumulative Impact Results
General Electric Turbines

Pollutant	Averaging Period	Total Modeled Concentration (µg/m^3)	Ambient Background Concentration (µg/m^3)	Total Concentration (µg/m^3)	NAAQS (µg/m^3)
NO_2	1-hour	95.61	76	171.61	188
PM-2.5	24-hour	2.49	17	19.49	35
	Annual	1.12	8	9.12	12

Table 4
NAAQS Modeling - Cumulative Impact Results
Siemens Turbines

Pollutant	Averaging Period	Total Modeled Concentration (µg/m^3)	Ambient Background Concentration (µg/m^3)	Total Concentration (µg/m^3)	NAAQS (µg/m^3)
NO_2	1-hour	24.28	76	100.28	188
PM-2.5	24-hour	2.32	17	19.32	35
	Annual	0.97	8	8.97	12

PSD Increment Analysis

The 24-hour and annual PM-2.5 PSD increment analysis included emissions from the proposed source and emissions from existing sources from Virginia that were included in the NAAQS analysis. Tables 5 and 6 below present the results of the analysis for the General Electric and Siemens turbine options, respectively, and show that the 24-hour and annual PM-2.5 concentrations were below their applicable PSD increment.

Table 5
PSD Increment Modeling - Cumulative Impact Results
General Electric Turbines

Pollutant	Averaging Period	Modeled Concentration ($\mu g/m^3$)	Class II PSD Increment ($\mu g/m^3$)
PM-2.5	24-hour	4.82	9
	Annual	1.17	4

Table 6
PSD Increment Modeling - Cumulative Impact Results
Siemens Turbines

Pollutant	Averaging Period	Modeled Concentration ($\mu g/m^3$)	Class II PSD Increment ($\mu g/m^3$)
PM-2.5	24-hour	4.49	9
	Annual	1.01	4

NAAQS and PSD Increment Analyses Conclusions

Based on DEQ's review of the NAAQS and PSD increment analyses, assuming DEQ's regional office processing the permit application approved all of the emission estimates and associated stack parameters for the modeled scenarios, the proposed C4GT Project does not cause or significantly contribute to a predicted violation of any applicable NAAQS or Class II area PSD increment.

Toxics Analysis

The source is subject to the state toxics regulations at 9 VAC 5-60-300 et al. An analysis was conducted in accordance with the regulations and the predicted concentrations for each toxic pollutant were below their respective Significant Ambient Air Concentrations (SAAC). Tables 7 and 8 summarize the toxic pollutant modeling analysis results for the General Electric and Siemens turbine options, respectively.

Table 7
Toxics Analysis Maximum Predicted Concentrations
General Electric Turbines

Toxic Pollutant	Averaging Period	Maximum Modeled Concentration From Proposed Facility (μg/m^3)	SAAC (μg/m^3)
Acrolein	1-hour	2.78E-02	17.25
	Annual	2.60E-04	0.46
Formaldehyde	1-hour	3.76E-01	62.5
	Annual	9.43E-03	2.4

Table 8
Toxics Analysis Maximum Predicted Concentrations
Siemens Turbines

Toxic Pollutant	Averaging Period	Maximum Modeled Concentration From Proposed Facility (μg/m^3)	SAAC (μg/m^3)
Acrolein	1-hour	2.78E-02	17.25
	Annual	1.80E-04	0.46
Formaldehyde	1-hour	3.54E-01	62.5
	Annual	7.72E-03	2.4
Cadmium	Annual	2.00E-05	0.1
Chromium	Annual	2.00E-05	0.1
Nickel	Annual	4.00E-05	0.2

Additional Impact Analysis

In accordance with the PSD regulations, additional impact analyses were performed to assess the impacts from the proposed facility on visibility, vegetation and soils, and the potential for and impact of secondary growth. These analyses are discussed below.

Visibility

A Class II area visibility analysis using VISCREEN was not conducted because there are no protected vistas identified near the proposed C4GT Project site. Visibility in the area near the proposed facility will be protected by operational requirements, such as air pollution controls and clean burning fuels, and stringent limits on visible emissions, which will be incorporated into its air permit.

Vegetation and Soils

An analysis on sensitive vegetation types with significant commercial or recreational value was conducted. The analysis compared maximum predicted concentrations from the proposed facility against a range of injury thresholds found in various peer-reviewed research articles as well as criteria contained in the EPA document *A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals (EPA, 1980)*. Tables 9 and 10 show the maximum modeled concentrations for the General Electric and Siemens turbine options, respectively, were all below the respective thresholds (i.e., the minimum reported levels at which damage or growth effects to vegetation may occur). As a result, no adverse impacts on vegetation are expected.

Table 9
Comparison of Vegetation Sensitivity Thresholds to Maximum Modeled Concentrations from the C4GT Project
General Electric Turbines

Pollutant	Averaging Period	Maximum Modeled Concentration From Proposed Facility ($\mu g/m^3$)	Sensitive Vegetation Threshold ($\mu g/m^3$)
SO_2	1-hour	87.99	393
	3-hour	20.25	786
	Annual	0.17	18
NO_2	1-hour	199.98	940
	4-hour	34.90	3,760
	1-month	0.80	564
	Annual	0.62	94
PM-10	24-hour	3.24	150
CO	1-week	8.14	1,800,000

Table 10
Comparison of Vegetation Sensitivity Thresholds to Maximum Modeled Concentrations from the C4GT Project
Siemens Turbines

Pollutant	Averaging Period	Maximum Modeled Concentration From Proposed Facility ($\mu g/m^3$)	Sensitive Vegetation Threshold ($\mu g/m^3$)
SO_2	1-hour	87.99	393
	3-hour	20.25	786
	Annual	0.17	18
NO_2	1-hour	677.34	940
	4-hour	83.75	3,760
	1-month	0.71	564
	Annual	0.85	94
PM-10	24-hour	2.37	150
CO	1-week	6.13	1,800,000

The impact of the emissions on soils in the vicinity of the proposed project was evaluated. The soil type was determined from data collected from the United States Department of Agriculture's Natural Resources Conservation Service (NRCS) Soil Survey Geographic (SSGUGO) database and the NRCS Web Soil Survey tool. The soil types within the counties of Charles City, Henrico, and New Kent were examined.

The predominant soil types in Charles City County are a mixture of sandy and silt loams. In Henrico County, the predominant soil types are a variety of sandy and silt loams. In New Kent County, the predominant soil types are a variety of silt and sandy loams.

The soil types in these counties are generally considered to have a moderate to high buffering capacity and have adequate capacity to absorb acidic deposition without changing the soil pH. Based on the soil types and quantity of emissions from the proposed project, no adverse impact on local soils is anticipated.

Growth

The work force for the proposed facility is expected to be several hundred jobs during various phases of the construction. It is expected that a significant regional construction force is already available to build the proposed facility. Therefore, it is anticipated that no new housing, commercial or industrial construction will be necessary to support the C4GT Project during the 30-month construction schedule. The proposed facility will also require approximately 23 permanent positions. It is assumed that individuals that already live in the region will perform a number of these jobs. No new housing requirements are expected for any new personnel moving to the area. In addition, due to the small number of new individuals expected to move into the area to support the C4GT Project and the existence of some commercial activity in the area, new commercial construction would not be necessary to support the permanent work force. Additionally, no significant level of industrial related support will be necessary for the C4GT Project. Therefore, significant industrial growth is not expected.

Based on the growth expectations discussed above, no new significant emissions from secondary growth during the construction and operation phases of the C4GT Project are anticipated.

C. Class I Area Modeling Analysis

The FLMs are provided reviewing authority of Class I areas that may be affected by emissions from a proposed source by the PSD regulations and are specifically charged with protecting the Air Quality Related Values (AQRV) within the Class I areas. The closest Class I areas to the proposed facility is the Shenandoah National Park (SNP). It is approximately 152 kilometer (km) from the proposed facility. The other Class I areas within 300 km of the proposed facility but located at a distance greater than 152 km are James River Face Wilderness Area, Swanquarter National Wildlife Refuge, Dolly Sods Wilderness Area, and Otter Creek Wilderness Area.

Modeling guidance contained in the *Federal Land Managers' Air Quality Related Values Work Group (FLAG) Phase I Report – Revised (2010)* provides screening criteria for determining whether a source may be excluded from performing a Class I area AQRV modeling analysis. The FLMs may consider excluding a source from modeling if its total SO_2, NO_X, PM-10, and H_2SO_4 annual emissions (in tons per year, based on 24-hour maximum allowable emissions) divided by the distance (in km) from the Class I area is less than or equal to 10. The sum of the emissions for the proposed project for the worst-case turbine option (Siemens) is not expected to exceed approximately 672 tons per year (tpy). Therefore, the FLAG 2010 screening criteria for SNP is 4.42 (672 tpy/152 km). The screening criteria for all other Class I areas is less than 4.42 because these areas are located at a distance greater than 152 km. As a result, the USFS, the FWS, and the NPS each stated in a separate e-mail dated May 16, 2016 that an AQRV analysis was not required since the project is not expected to show any significant additional impacts to AQRVs.

However, even though an AQRV analysis was not required to be conducted, an analysis to assess compliance with the Class I PSD increments for PM-10, PM-2.5 and NO_2 was conducted. The emissions used in the Class I area modeling were the same as those used for the Class II area modeling. A preliminary modeling analysis for PM-10 and NO_2 was conducted to assess the maximum predicted ambient impacts at a distance of 50 km from the proposed facility. As shown in Tables 11 and 12, the proposed facility's maximum predicted ambient impacts for PM-10 (24-hour and annual averaging periods) and NO_2 (annual averaging period) for the General Electric and Siemens turbine options, respectively, were less than the applicable Class I SILs. Therefore, the maximum predicted ambient impacts for PM-10 (24-hour and annual averaging periods) and NO_2 (annual averaging period) at the closest Class I area (i.e., SNP) were also expected to be below the applicable Class I SILs. As a result, no additional air quality analysis was required for these pollutants.

Table 11
Summary of Maximum Predicted PM-10 and NO_2 Concentrations at 50 km from the C4GT Project
General Electric Turbines

Pollutant	Averaging Period	Maximum Predicted Concentration From Proposed Facility at 50 km ($\mu g/m^3$)	Class I Significant Impact Level ($\mu g/m^3$)
PM-10	24-hour	0.06802	0.3
	Annual	0.0043	0.2
NO_2	Annual	0.0083	0.1

Table 12
Summary of Maximum Predicted PM-10 and NO_2 Concentrations at 50 km from the C4GT Project
Siemens Turbines

Pollutant	Averaging Period	Maximum Predicted Concentration From Proposed Facility at 50 km ($\mu g/m^3$)	Class I Significant Impact Level ($\mu g/m^3$)
PM-10	24-hour	0.1000	0.3
	Annual	0.0062	0.2
NO_2	Annual	0.0093	0.1

The PM-2.5 modeling analysis conducted compared the maximum predicted ambient impacts at a distance of 50 km from the proposed facility to the applicable PM-2.5 Class I PSD increments because the provisions of the PM-2.5 SILs in 40 CFR 51.166(k)(2) and 52.21(k)(2) were vacated in January 2013 and the VADEQ does not currently have state-specific SILs for the purpose of excluding a project from performing a full impact analysis. Tables 13 and 14 show the maximum predicted ambient impacts for PM-2.5 (24-hour and annual averaging periods) for the General Electric and Siemens turbine options, respectively, were less than the applicable Class I PSD increments. Therefore, the maximum predicted ambient impacts for PM-2.5 (24-hour and annual averaging periods) at the closest Class I area (i.e., SNP) were also expected to be below the applicable Class I PSD increments.

Table 13
Summary of Maximum Predicted PM-2.5 Concentrations at 50 km from the C4GT Project
General Electric Turbines

Pollutant	Averaging Period	Maximum Predicted Concentration From Proposed Facility at 50 km ($\mu g/m^3$)	Class I PSD Increment ($\mu g/m^3$)
PM-2.5	24-hour	0.10574	2
	Annual	0.0119	1

Table 14
Summary of Maximum Predicted PM-2.5 Concentrations at 50 km from the C4GT Project
Siemens Turbines

Pollutant	Averaging Period	Maximum Predicted Concentration From Proposed Facility at 50 km ($\mu g/m^3$)	Class I PSD Increment ($\mu g/m^3$)
PM-2.5	24-hour	0.1200	2
	Annual	0.0102	1

Summary of Class I Area Analysis

Based on DEQ's review of the Class I area modeling analyses, the proposed C4GT Project does not cause or significantly contribute to a predicted violation of any applicable Class I area PSD increment.

D. Other Modeling Considerations

Ozone

An assessment to estimate the impact on ozone from the proposed facility's NO_X and VOC emissions was conducted. This analysis was based on the highest daily maximum 8-hour ozone impacts from comparable hypothetical NO_X and VOC sources that were identified as representative of the proposed facility from multiple hypothetical source model simulations contained in EPA's *Guidance on the Development of Modeled Emission Rates for Precursors (MERPs) as a Tier 1 Demonstration Tool for Ozone and $PM_{2.5}$ under the PSD Permitting Program* (December 2, 2016). Therefore, based on the guidance, approximately 1.19 parts per billion (ppb) and 1.22 ppb of ozone might be formed on a worst-case day as a result of NO_X and VOC emissions from C4GT for the General Electric and Siemens turbine options, respectively. The monitored ozone design value for the area is 62 ppb, as measured at the nearby DEQ Shirley Plantation monitor for the period 2013 through 2015. The addition of the project's worst-case daily impact to the design value equals 63.19 ppb and 63.22 ppb for the General Electric and Siemens turbine options, respectively, which is well below the 8-hour ozone NAAQS of 70 ppb. It is important to note that this approach is highly conservative because it adds a daily maximum 8-hour ozone concentration to a design value. The project's actual modeled impact on the design value (4^{th} highest ozone concentration averaged over 3 years) is likely to be much less than the result obtained using this approach, based on DEQ's photochemical modeling experience.

In addition, Virginia implements the Cross-State Air Pollution Rule (CSAPR) Update regulation (81 FR 74505, October 26, 2016) under a Federal Implementation Plan (FIP). This FIP includes new units set asides within the Virginia budget for ozone season NO_X emissions that are equivalent to 2% of the total state budget plus the projected amount of emissions from planned units. Table VII.E-1 (81 FR 74565) provides that Virginia's new unit set aside amount is 562 tons, with a total EGU emissions budget of 9,223 tons. All units subject to CSAPR (those with capacities of greater than 25 MW and firing fossil fuel) must operate in the cap and trade program. EPA's technical analyses for this program indicate that this rule addresses Good Neighbor transport requirements for EGUs under Section 110(a)(2)(D)(I) of the CAA. As long as Virginia units operate under this program, additional modeling is therefore unnecessary to demonstrate compliance with Good Neighbor provisions since Virginia's emissions must be no higher than the assurance levels associated with the rule and listed in Table VII.E-2 (81 FR 74567). Otherwise, units would need to provide penalty allocations equivalent to a 3:1 ratio of their emissions over the assurance levels.