**Engineering Analysis**

Source Name: **Balico LLC/Chickahominy Power** Permit No.: **52610-001**

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

Date: **May 28, 2019**

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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 capacity of 1,650 MW. The facility will be located 3.4 km (2.1 mi) SSE of Roxbury, Virginia and 10 km (6.3 mi) west of Providence Forge, Virginia in Charles City County. The site will be located on a 185-acre parcel ESE of the intersection of State Route 106 (Roxbury Rd.) and State Route 685 (Chambers Rd.) and adjacent to the Dominion Energy Chickahominy Substation.

This is the second power station proposed in this region. The C4GT Power Station (Permit Number 52588), to be located 1.6 km (1.0 mi) NE of the Chickahominy Power Station, was issued a major New Source Review permit in April 2018. As of the date on this Engineering Analysis, C4GT has not notified DEQ of the start of construction of that project.

Site Suitability:

The Chickahominy Power facility will be located on a site that is suitable from an air pollution standpoint. The area is rural and sparsely populated, surrounded by farmland and small commercial and industrial operations (i.e., car part lots, storage units, and a construction contractor), in addition to an existing substation. The Charles City County landfill is located 2.2 km (1.4 mi) to the east. The nearest residence is about 0.4 km (0.25 mi) to the southeast, with others about 0.8 km (0.5 mi) to the south and 1 km (0.6 mi) to the west. The nearest grade schools are located near Charles City, approximately 14 km (8.7 mi) away to the southeast. There is a small preschool/day care center about 6.5 km (4 mi) to the north. The nearest hospital/medical center is in Hopewell, over 18 km (11 mi) away, as is the nearest senior care facility.

A screening report for the site was obtained through EPA's EJSCREEN utility. Reports were based on radii of 1, 2, and 5 miles around the proposed site. The air quality EJ indices were all less than 60% (see Appendix C attached). As noted in Sections BACT and MODELING, the stationary source complies with all applicable requirements and ambient air quality standards.

There are no Class I areas (an area such as a national park or designated national wilderness areas) within 100 km (62 mi) of the proposed facility (see Table 1).

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, VA (USNPS) | 153 km ( 95 mi) |
| James River Face Wilderness Area, VA (USFS) | 196 km (122 mi) |
| Dolly Sods Wilderness Area, VA (USFS) | 256 km (159 mi) |
| Swanquarter National Wildlife Refuge, NC (USFWS) | 238 km (148 mi) |
| Otter Creek Wilderness Area, WV (USFS) | 274 km (170 mi) |

The area is in attainment with National Ambient Air Quality Standards (NAAQS), meaning that air monitoring has shown that, currently, the air meets the federal standards set for certain air pollutants to protect public health and welfare. Being a "fossil fuel-fired steam electric plant of more than 250 MMBtu/hr heat input," the source will be categorized as a major source with a potential to emit over 100 tons/yr of regulated NSR pollutants. These include nitrogen oxides ($NO_x$ or $NO_2$), carbon monoxide (CO), particulate matter filterable only (PM), 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. Therefore, Prevention of Significant Deterioration (PSD) permitting (Article 8) for those pollutants is triggered - as well as for the “significant” emissions of volatile organic compounds (VOC), sulfuric acid mist ($H_2SO_4$) and sulfur dioxide ($SO_2$). See Section III.B for more information about PSD permitting.

The source will not be major for hazardous air pollutants (HAP) (with total emissions of less than 10 tons of a single HAP or less than 25 tons total HAP) and the source will be subject to Regulations applicable to minor (area) sources of HAP and the State Toxics Rule (9 VAC 5-60-300, Rule 6-5). See Section III.F.2 for additional information.

Two existing electric transmission lines and a substation are adjacent to the site. The area is supplied with a natural gas pipeline from Virginia Natural Gas Company.

The site is an upland area (elevation 120-140 ft) with cleared areas. 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 Body Certification Form in the application).

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) 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 if it has the potential to emit over 100 tons of any regulated pollutant. 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. 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 $NO_2$. DEQ found the proposed Chickahominy Power 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 Attachment B - Modeling Memo, Section C.

   Preliminary modeling analysis for the Class II areas (all other areas not designated as Class I areas) predicted that the maximum ambient air impacts (from either turbine option) for $SO_2$ (1-hr, 3-hr, 24-hr, and annual); CO (1-hour and 8-hour averaging periods); and $PM_{10}$ (annual averaging period) were below applicable SILs. No further analyses were required for these pollutants at the indicated averaging periods.

The preliminary modeling results for $NO_2$ (1-hour and annual averaging periods) and for $PM_{10}$ (24-hr 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. A full impact analysis can consist of examining the cumulative impact of the project pollutant emissions on both the NAAQS established by EPA for the Clean Air Act, and PSD Increment (no PSD increment analysis was done for $NO_2$ 1-hr avg period because there is no EPA Class II PSD increment for this pollutant for that averaging time).

The predicted impacts for $NO_2$, $PM_{10}$, and $PM_{2.5}$ from the cumulative impact analyses were less than the applicable 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 Chickahominy Power, are subject to the standards in 9 VAC 5-60-300 et seq. Chickahominy Power calculated the emissions of toxic pollutants from all of the emission units proposed for the site. Chickahominy Power modeled emissions of toxic pollutants for which proposed emissions exceeded the thresholds in 9 VAC 5-60-320 (acrolein, formaldehyde, cadmium, chromium, and nickel on an hourly and annual basis, and beryllium, lead and mercury on an annual basis). Modeling demonstrated that proposed emissions of these toxics pollutants are well below the associated Significant Ambient Air Concentrations (SAACs) that DEQ has established for each pollutant, based on available toxicity data, which could injure human health if exceeded. See attached Modeling Memo, Section B for Toxics Analysis.

A visibility analysis may be conducted to assess the potential for visual plume impacts in Class II protected vista areas within 50 km of the projected site; however, there are no such protected vista areas (i.e., airports, state parks, or state historic sites) near the Chickahominy Power site. The facility is required to use clean-burning fuels, 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 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.

This project is not expected to require or cause an increase in residential, commercial or industrial construction near the plant. Therefore, secondary impacts on emissions from these types of activities are not anticipated.

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. In 2016 the Charles City County Board of Supervisors approved a Special Use Permit for the operation of the facility.

   The proposed Chickahominy 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.

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. Air Quality characteristics and performance requirements defined by SAPCB regulations: 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 has been shown to be in 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. The health impact of air quality deterioration that 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: 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 74).

   c. Anticipated impact of odor on surrounding communities or violation of the SAPCB Odor Rule: 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 while developing 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 and carbon content, good combustion practices (GCPs), high combustion efficiency, and clean-burning "low-$NO_x$" burners, as well as “add-on” air pollution controls (SCR for $NO_x$ removal and an Oxidation Catalyst for CO, VOC, and VOC toxic pollutant control). GCPs include controlled fuel/air mixing, adequate temperature, and gas residence time, among other practices. 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 three power blocks consisting of a combustion turbine with a heat recovery steam generator (HRSG) and a reheat condensing steam turbine generator (three 1 x 1 configuration). The turbine model proposed is a MHPS M501JAC turbine. The project will have a nominal net generating capacity of 1,650 MW. The proposed fuel for the turbines 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 GCPs (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 two natural gas-fired auxiliary boilers, three fuel gas heaters, 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.

This facility is not proposing duct firing in the HRSGs and is proposing air-cooled turbines that will not require cooling towers.

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

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

| Pollutant | Emissions (tons/yr) |
|---|---|
| $NO_x$ | 407 |
| CO | 323 |
| $SO_2$ | 62 |
| VOC | 211 |
| PM (filterable only) | 169 |
| $PM_{10}$ | 169 |
| $PM_{2.5}$ | 169 |
| $CO_2e$ | 6,479,692 |
| Sulfuric acid mist ($H_2SO_4$) | 65 |
| Acrolein | 0.23 |
| Formaldehyde | 9.86 |
| Beryllium | 0.00064 |
| Cadmium | 0.059 |
| Chromium | 0.075 |
| Lead | 0.027 |
| Mercury | 0.014 |
| Nickel | 0.12 |

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

| **Ref. No.** | **Equipment Description** | **Rated Capacity** | **Federal Requirements** |
|---|---|---|---|
| CT-1 | Mitsubishi Hitachi Power Systems (MHPS) M501JAC combustion turbine generator | 4,070 MMBtu/hr CT (HHV) | NSPS, Subpart KKKK |
| CT-2 | Mitsubishi Hitachi Power Systems (MHPS) M501JAC combustion turbine generator | 4,070 MMBtu/hr CT (HHV) | NSPS, Subpart KKKK |
| CT-3 | Mitsubishi Hitachi Power Systems (MHPS) M501JAC combustion turbine generator | 4,070 MMBtu/hr CT (HHV) | NSPS, Subpart KKKK |
| HRSG1, 2, & 3 w/STG | Mitsubishi heat recovery steam generators with steam turbine generators | 178 MW each at ISO | None |
| B-1 | Auxiliary Boiler (natural gas-fired) | 84 MMBtu/hr (HHV) | NSPS Subpart Dc |

| Ref. No. | Equipment Description | Rated Capacity | Federal Requirements |
|---|---|---|---|
| B-2 | Auxiliary Boiler (natural gas-fired) | 84 MMBtu/hr (HHV) | NSPS Subpart Dc |
| FGH-1 | Fuel Gas Heater (natural gas-fired) | 12 MMBtu/hr each (HHV) | NSPS Subpart Dc |
| FGH-2 | Fuel Gas Heater (natural gas-fired) | 12 MMBtu/hr each (HHV) | NSPS Subpart Dc |
| FGH-3 | Fuel Gas Heater (natural gas-fired) | 12 MMBtu/hr each (HHV) | NSPS Subpart Dc |
| EG-1 | Emergency Generator (S15 ULSD) | 3000 kW | NSPS IIII, MACT ZZZZ |
| FWP-1 | Fire Water Pump (S15 ULSD) | 376 bhp | NSPS IIII, MACT ZZZZ |
| CB | Electrical Circuit Breakers | 22,800 lbs $SF_6$ total | None |
| NGL-1 | Fugitive equipment leaks from natural gas piping components | --- | None |
| T-1 | ULSD storage tank | 572 gallons | None |
| T-2 | ULSD storage tank | 2,500 gallons | None |

1. Combustion Turbine Generators with HRSG and steam turbine generator (CT-1, CT-2, CT-3)

   a. <u>Combustion Turbines (CT-1, CT-2, CT-3)</u>

   The source has proposed the following power block: the installation of three 4,070 MMBtu/hr Mitsubishi-Hitachi Power Systems (MHPS) 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.

   The turbines 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. The proposed plant can be operated as a baseload plant (high load) but may operate for sustained periods at lower loads, depending on demand.

   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 maintenance events requiring alternate operating scenarios for the CTs, i.e., 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 PM, $PM_{10}$, $PM_{2.5}$, $NO_x$ 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.

   b. <u>Heat Recovery Steam Generators (HRSG)</u>

   The proposed facility will use three 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 (see part “c” below). The heat recovered is used in the combined-cycle plant for additional steam generation. 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.

c. Steam Turbine Generator (STG)

The proposed project includes one reheat, condensing steam turbine generator for each combustion turbine. 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. The STG set associated with the MHPS turbines is designed to produce up to approximately 178 MW of electrical output at ISO conditions. No pollutants are emitted from the STG.

2. Ancillary Equipment

a. Auxiliary Boilers (B-1, B-2)

The proposed facility will include two natural gas-fired, auxiliary boilers rated at 84 MMBtu/hr. The auxiliary boilers will provide steam to the STGs at startup and at cold or warm starts to warm up the HRSGs. The steam from the auxiliary boilers will not be used to augment the power generation of the CTs or STGs. The boilers are proposed to operate up to 8760 hrs/yr.

b. Fuel Gas Heaters (FGH-1, FGH-2, FGH-3)

The proposed facility will include three 12 MMBtu/hr, natural gas-fired, fuel gas heaters. The heaters 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 heaters are proposed to operate up to 8760 hrs/yr.

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

The proposed facility will include a 3,000 kW diesel-fired emergency generator that will be operated up to 500 hours per year. 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 376 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.

e. Circuit Breakers (CB)

The proposed project will include several circuit breakers (holding a total of 22,800 lbs of the greenhouse gas sulfur hexafluoride ($SF_6$)).

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

The proposed project will include one 2,500-gallon and one 572-gallon, fixed-roof, horizontal, distillate oil storage tanks to provide fuel for the emergency generator and fire water pump, respectively.

g. 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 | February 22, 2017 (amended November 2, 2018 and January 10, 2019) |
| Date application was deemed complete | January 10, 2019 |
| Proposed construction commencement date | Summer 2019 |
| Proposed startup date | May 1, 2021 |

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

Proposed emissions are primarily products of combustion from the combined cycle units. There are also emissions from the auxiliary boilers, fuel gas heaters, emergency generator, emergency fire water pump, 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 will be based on CEMS data and initial performance testing. 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 testing for PM, $PM_{10}$, $PM_{2.5}$, and VOC from the turbines. 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. Particulate emissions from natural gas are mainly due to incomplete combustion of the low-ash gaseous fuel and consist of $PM_{10}$ or smaller particulate matter, 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 VOC testing every five years (Condition 63 testing 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 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 (GWP) 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 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 operating at either 8,760 hrs/yr without SU/SD, or with the turbines operating normally for 7,216 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 boilers (B-1, B-2), and fuel gas heaters (FGH1, FGH-2, FGH-3) 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 1 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 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 typically from semi-conductors/circuit breakers. This facility has electrical circuit breakers which contain $SF_6$.

Since the Chickahominy Power 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.3 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. $SO_2$ and $H_2SO_4$ exceeded the applicable PSD significance level so the facility will be subject to PSD for $SO_2$ and $H_2SO_4$ 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. PSD review was not triggered for lead (see III.F.2. for more information on permitting applicability for lead).

Table 3 - PSD Permitting applicability

| Pollutant | Total TPY | PSD Major Threshold (TPY)* | Over Major Threshold? | PSD Significance Rate (TPY)** | PSD Required? |
|---|---|---|---|---|---|
| PM | 168 | 100 | **Yes** | 25 | **Yes** |
| $PM_{10}$ | 168 | 100 | **Yes** | 15 | **Yes** |
| $PM_{2.5}$ | 168 | 100 | **Yes** | 10 | **Yes** |
| $NO_x$ | 407 | 100 | **Yes** | 40 | **Yes** |
| CO | 323 | 100 | **Yes** | 100 | **Yes** |
| $SO_2$ | 62 | 100 | No | 40 | **Yes** |

| Pollutant | Total TPY | PSD Major Threshold (TPY)***** | Over Major Threshold? | PSD Significance Rate (TPY)****** | PSD Required? |
|---|---|---|---|---|---|
| VOC | 211 | 100 | **Yes** | 40 | **Yes** |
| $CO_2e$ | 6,479,692 | — | **Yes** | 75,000 | **Yes** |
| Lead | 0.027 | 100 | No | 0.6 | No |
| $H_2SO_4$ | 64 | 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, CT-3) 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. To be in compliance with this regulation, 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 limited to 2 ppmvd, 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. 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.

   Subpart Dc: The auxiliary boilers (B-1, B-2) and fuel gas heaters (FGH-1, FGH-2, FGH-3) are subject to NSPS Subpart Dc Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units as steam-generating units between 10 and 100 MMBtu/hr. As natural gas-fired units, they will be required to keep records of the amount of natural gas burned in each unit every calendar month. [40 CFR 60.48c(g)(2)].

2. Subpart IIII*: The emergency diesel fire water pump (FWP-1) and diesel emergency generator (EG-1) are subject to NSPS Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines. The 376 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 3000 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. BACT requirements cannot be less stringent than Federal Standards (see Sections III.G.2.c and III.G.5.c for BACT limits).

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

3. Subpart TTTT Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units: As of June 2019, 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. Until Virginia requests and is granted delegation to enforce this regulation, this regulation will be enforced by EPA.

4. Non-applicable NSPS 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.

2. Non-applicable MACT 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. As an area HAP source, the facility will not be subject to MACT Subpart YYYY for turbines. 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.

   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 boilers (B-1, B-2) are not subject to this regulation [40 CFR 63.11195(e)].

E. Other:

1. Cross State Air Pollution Rule Update (CSAPR Update): On September 7, 2016, EPA finalized a rule updating the CSAPR and implementing new Federal Implementation Plans (FIPs). Virginia implements the CSAPR and CSAPR Update requirements through the FIP as per 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 pollutant that is not subject to PSD is lead (See Table 3 above).

   Minor NSR applicability is determined by the <u>uncontrolled</u> 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 lead content of the fuel is not variable and no add-on controls are proposed to control lead. Total, <u>uncontrolled</u> lead emissions from the facility are estimated to be no more than 0.027 tons/yr. This is below the minor NSR exemption rate for lead of 0.6 tons/yr found in 9 VAC 5-80-1105.C. Lead is also considered a toxic pollutant under 9 VAC 5-60-300 (see discussion under III.F.2 below).

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. Proposed emissions of acrolein, formaldehyde, and the compounds of beryllium, cadmium, chromium, and nickel on an hourly and annual basis, and compounds of lead and mercury on an annual basis, exceed the exemption levels for those respective toxic air pollutants. Therefore, these pollutants are required to be included in a NSR permit. 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 SAACs (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).

The facility, as proposed, will be a natural gas-fired, power generating plant operating primarily as a base load plant. This does not make it particularly compatible with a solar grid, which is optimal for a load-following plant that may operate at low loads for prolonged periods. A combined cycle turbine operates most efficiently at higher loads and infrequent load changes. 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 smaller, 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 https://www.powermag.com/whatever-happened-to-fuel-cells/).

Chickahominy Power 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 Chickahominy Power application. The scope of the application is a natural gas-fired, combined cycle combustion turbine generator with HRSG and steam turbine. DEQ has endeavored to take into consideration the size, proposed operating scenarios (business model), brand of combustion turbines proposed by Chickahominy Power, 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 Chickahominy Power 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 2013 forward, with a few facilities included from prior years (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 23 large-scale CCS projects around the world that are operating or under

construction, only two are power plants using post-combustion capture. These facilities are currently operating in North America: the 110-MW Boundary Dam power-generating facility in Saskatchewan, Canada and the Petra-Nova plant in Texas. Both projects, however, are for pulverized coal-fired plants, not natural gas-fired plants. (http://www.globalccsinstitute.com/projects/large-scale-ccs-projects). The Boundary Dam CCS project generated initial funding of $240 million from the Canadian government and profits from sale of the $CO_2$ to an oil extraction plant about 66 km from the power plant. The Petra Nova 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 Chickahominy Power Station will burn natural gas fuel and does not have funding from outside entities for implementation of CCS.

$CO_2$ transport poses a problem as well. There are no oil extraction sites or other entities that would purchase the captured $CO_2$ nearby to the Charles City location. 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. Therefore, CCS is only marginally available and technically feasible for a natural gas-fired power plant in central Virginia.

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 that reflects the maximum degree of reduction for a particular pollutant, then the best means of comparison is of emission limits rather than percent control efficiency.

The use of low carbon fuels like natural gas instead of coal can reduce $CO_2$ emissions. Table C-1 to Subpart C of Part 98 –Default $CO_2$ Emission Factors and High Heat Values for Various Types of Fuel – lists a $CO_2$ emission factor for Bituminous coal of 103 kg $CO_2$/mmBtu and for #2 oil 73.96 kg $CO_2$/mmBtu and the factor for natural gas is 53.06 kg $CO_2$/mmBtu. The only fuels with a lower emission factor are coke oven gas (46.85 kg/mmBtu), landfill gas, and "other" biomass gases (both at 52.07 kg/mmBtu). Those fuels, however, have a Btu content about half of natural gas per standard cubic foot so it may require the burning of twice as much of those gases to achieve the same heating value as natural gas.

Efficient power generation is a good measure of $CO_2$ emission potential but it is measured a bit differently than other parameters. 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 (kg/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, duct-firing, 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. Many variables must be taken into consideration: heating value of the fuel (HHV=higher heating value, LHV=lower heating value), gross power output or net power output, 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.

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 to conclude if the limit is comparable to another. 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[1] 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.

Of the technologies mentioned above, CCS would be able to reduce $CO_2$ emissions by the greatest amount, followed by a combination of efficient power generation and the use of low-carbon fuels.

iv. Evaluation of Step 3 control technologies (Step 4):
As mentioned in III.G.1.a.ii above, CCS is only marginally effective, available, and technically feasible for a natural gas combustion turbine, and has not been demonstrated. Additionally, 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,[2] 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.

1 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)
2 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)

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 2013 in order of startup year - actual or (anticipated)

<u>MHPS</u> RBLC GHG limits (with or without duct burning)

| **Permit Year** | **Startup Year*** | **Facility** | **Size/Type** | **GHG BACT limits** | **Basis** |
|---|---|---|---|---|---|
| 2013 | 2016 | Dominion Brunswick, VA (M501GAC) | 1400 MW NGCC | 7500 Btu/kWh (net HHV) (full load corrected to ISO)<br>920 lb/MWh (net HHV)<br>(achieving 6970 Btu/kWh and 820 lb/MWh in 2017 according to www.eia.gov) | Thermal efficiency |
| 2014 | Mid-2017 | ODEC Wildcat PT, MD (M501G) | 1000 MW NGCC plant | 7500 Btu/kWh (not including SU/SD)<br>946 lb/MWh<br>(achieving 7139 Btu/kWh and 840 lb/MWh from Jan to Sept 2018 according to www.eia.gov) | Exclusive use of pipeline NG and high efficiency turbine |
| 2014 | mid-2017 | Grand River Energy Ctr, OK (Unit 3)(M501JAC) | EUG 8.<br>495 MW NGCC | (achieving 7088 Btu/kWh and 834 lb/MWh from Jan to Sept 2018 according to www.eia.gov) | PSD was not triggered for CO2e but turbine operating data is useful. |
| 2016 | mid-2018 | Dominion VA – Greensville, VA (M501J) | 1600 MW NGCC plant | 6457 Btu/kWh initial test up to 7212 Btu/kWh net, (full load, no DB, corrected to ISO conditions) after 30+ years of operation.<br>812 lb/MWh initial up to 890 lb/Mwh net output after 30 years of operation | Use of NG, high efficiency design and operation, and low carbon fuel |
| 2016 | (2019) | Trinidad Gen Sta, TX (M501J) | 530 MW NGCC | 937 lb/MWh | GCPs |
| 2018 | (2021) | Entergy Texas Montgomery, TX (M501GAC) | 993 MW | 884 lb/MWh gross output w/DB (8% degradation over unit lifetime)<br>7455 Btu/kWh HHV 12-mo rolling avg, excludes SU/SD, (8% degradation) | |
| 2018 | (2021) | New Covert Gen, MI (M501G) | 1230 MW NGCC | 7978 Btu/kWh (12 mo avg) | Energy saving measures & NG |

Other turbines that have commenced operation

| **Permit Year** | **Startup Year*** | **Facility** | **Size/Type** | **GHG BACT limits** | **Basis** |
|---|---|---|---|---|---|
| 2015 | 2017 | Exelon Colorado Bend II Enrgy Ctr, TX (GE 7HA.02 | 1100 MW NGCC plant | 879 lb/MWh HHV gross<br>7395 Btu/kWh<br>(does not include SU/SD)<br>(achieving 6600 Btu/kWh net and 777 lb/MWh in 2017 according to www.eia.gov) | Efficient processes, practices, and designs. |
| 2010 | 2013 | Calpine Russell City EC, CA (Siemens 501 FD) | 650 MW NGCC | 7730 Btu/kWh (HHV net ISO w/o DB)<br>(12.3% degradation)<br>(achieving 7606 Btu/kWh and 895 lb/MWh in 2017 according to www.eia.gov) | Energy Efficiency/ GCPs |
| 2011 | 2014 | PacifiCorp Lake Side 2, UT (SGT6-5000F) | 728 MW NGCC | 950 lb/MWh (gross)<br>6918 Btu/kW (HHV)<br>(achieving 6542 Btu/kWh and 770 lb/MWh in 2017 according to www.eia.gov) | Energy Efficiency/ GCPs |

| Permit Year | Startup Year* | Facility | Size/Type | GHG BACT limits | Basis |
|---|---|---|---|---|---|
| 2012 | 2014 | Calpine DPEC, TX (Siemens FD3 501F) | 1300 MW plant Phase II, CTG6: | 920 lb/MWh net (>90% load, no DB, ISO) 7730 Btu/kWh (HHV net ISO w/o DB) (12.3% degradation) (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/ GCPs |
| 2011 | 2014 | LCRA Ferguson replacement, TX (GE 7FA) | 590 MW NGCC | 918 lb/MWh (365-day rolling avg) 7720 Btu/kWh (net HHV) (5% degradation) (achieving 6941 Btu/kWh and 817 lb/MWh in 2017 according to www.eia.gov) | Thermal Efficiency |
| 2014 | 2014 | West Deptford Energy, NJ (Siemens) | 750 MW NGCC | 947 lb/MWh gross w/DB 7,756 Btu/kWh net HHV at ISO (achieving 7088 Btu/kWh and 834 lb/MWH in 2017 according to www.eia.gov) | Turbine efficiency and use of NG as clean fuel |
| 2013 (EPA GHG) Not in the EPA RBLC | 2016 | FPL Port Everglades, FL (SGT6-8000H) | 1250 MW NGCC (no duct burners) with oil backup | 830 lb/MWh net NG fuel (no duct firing) (annual average) (achieving 6733 Btu/kWh and 792 lb/MWh in 2017 according to www.eia.gov) | Energy efficiency |
| 2013 | 2016 | Panda Liberty, PA, (SGT6-8000H) | 829 MW NGCC | 6735 Btu/kWh LHV (no duct firing, corrected to ISO conditions) (achieving 6615 Btu/kWh and 778 lb/MMBtu in 2017 according to www.eia.gov) | |
| 2013 | 2016 | Panda Patriot, PA, (SGT6-8000H) | 829 MW NGCC | 6735 Btu/kWh LHV (no duct firing, corrected to ISO conditions) (achieving 6590 Btu/kWh and 775 lb/MMBtu in 2017 according to www.eia.gov) | |
| 2013 | 2017 | Oregon Clean Energy, OH (Siemens SGT-8000H) | 870 MW NGCC | 833 lb/MWh gross output (ISO, no duct firing) and compliance is based on achieving 7227 lb/MWh. (achieving 6816 Btu/kWh and 802 lb/MWh in 2017 according to www.eia.gov) | High efficiency combustion technology |
| 2014 | 2017 | CPV St. Charles, MD (GE7FA.05) | 725 MW NGCC | 7109 Btu/kWh gross HHV at ISO, full load, no DB, 878 lb/MWh (achieving 7021 Btu/k/Wh and 826 lb/kWh in 2017 according to www.eia.gov) | Efficient turbine technology, use of pipeline NG, minimize SU/SD |
| 2014 | 2017 | Green Energy Panda Stonewall, VA (SGT6-5000F) | 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 7048 Btu/kWh net and 829 lb/MWh in 2017 according to www.eia.gov) | Manufacturer-recommended operation and use of natural gas. |
| 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 7199 Btu/kWh net and 847 lb/MWh in 2017 according to www.eia.gov) | Not listed |

| Permit Year | Startup Year* | Facility | Size/Type | GHG BACT limits | Basis |
|---|---|---|---|---|---|
| 2013/ 2016 | 2017 | Holland Engy Ctr, MI (Siemens) | 114 MW | 992 lb/MWh<br>8361 Btu/kWh HHV net<br>(at ISO, baseload, w/o DB, w/o transformer losses) (achieving 7712 Btu/kWh net and 907 lb/MWh in 2017 according to www.eia.gov) | Energy efficiency measures and use of low carbon fuel (pipeline NG) |

Other turbines pending or just recently commencing operation

| Permit Year | Startup Year* | Facility | Size/Type | GHG BACT limits | Basis |
|---|---|---|---|---|---|
| 2012 | Early-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 |
| 2014 | Mid-2018 | Footprint Pwr Salem Harbor Sta, MA<br>(GE Energy 107F Series 5) | 692 MW NGCC plant | 825 lb/MWh (full load, no DB, ISO)<br>895 lb/MWh 365 day average<br>(achieving 881 lb/MWh from June to Sep 2018) | Not listed |
| 2015 | 2018 | Invenergy Lackawanna Energy Ctr, PA<br>(GE 7HA.02 (air cooled) | 1500 MW | 1,629,115 TPY w/DB (achieving 7002 Btu/kWh and 824 lb/MWh from Jan to Sept 2018 according to www.eia.gov) | |
| 2015 | 2018 | CPV Towantic, CT<br>(GE 7HA.01) | 785 MW dual fuel CC plant (as built) | 809 lb/MWh (net, one time initial test, corrected to ISO, $CO_2$)<br>Max lifetime 7220 Btu/kWh net HHV, full load, no DB on a 12-mo rolling average (achieving 6739 Btu/kWh and 793 lb/MWh from Jan to Sept 2018 according to www.eia.gov) | Not listed |
| 2016 | Mid-2018 | PSEG Sewaren Gen Sta, NJ<br>(GE7HA.02) | 585 MW NGCC | 888 lb/MWh gross w/DB (achieving 7020 Btu/kWh and 826 lb/MWh from Jan to Sept 2018 according to www.eia.gov) | |
| 2015 | Late-2018 | Caithness Moxie Freedom, PA<br>(GE 7HA.02) | 1050 MW NGCC | 1,000 lb/MW gross<br>6973 Btu/kWh HHV gross<br>(new, clean ISO, no duct firing)<br>7368 Btu/kWh HHV gross<br>(no duct firing, ISO, for lifetime of plant) (achieving 6557 Btu/kWh and 772 lb/MWh from Jan to Sept 2018 according to www.eia.gov) | |
| 2014 | Mid-2018 | Keys Enrgy Ctr, MD (Siemens SGT6-5000fee) | 735 MW NGCC plant | 869 lb/MWh gross (w or w/o DB) (achieving 7179 Btu/kWh and 845 lb/MWh from Jan to Sept 2018 according to www.eia.gov) | "$CO_2$ CEMS" and two turbines cannot startup simultaneously. |
| 2015 | (Late 2018) | York Energy Ctr Block 2, PA (GE7F.05) | 835 MW (dual fuel) | 883 lb/MWh w/DB | GCPs and oxidation catalyst |
| 2016 | (2019) | Rockwood Energy Center, TX<br>(various turbine models proposed, the lowest emission rate is for the GE7HA.02 model) | 1068 MW NGCC | 865 lb/MWh HHV<br>(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) | Rockwood Energy Ctr, TX<br>(GE 7HA.02) | 1068 MW | 865 lb/MWh HHV<br>(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. |

| Permit Year | Startup Year* | Facility | Size/Type | GHG BACT limits | Basis |
|---|---|---|---|---|---|
| 2016 | (2019) | FPL Okeechobee Clean Energy Ctr, FL<br>(GE 7HA.02) | 1600 MW | 800 lb/MWh (new, full load, ISO)<br>850 lb/MWh normal operation (excludes SU/SD, fuel switching, tuning, or malfunction)<br>1000 lb/MWh during "non-normal" operation | Use of low-emitting fuels and technologies. |
| 2015 | (2019) | Panda Mattawoman Energy Ctr, MD<br>(Siemens SGT-8000H 1.4 optimized) | 990 MW NGCC | 865 lb/MWh gross with or without duct firing, and includes SU/SD<br>6793 Btu/kWh net LHV<br>(ISO, with duct firing) | Pipeline quality natural gas, efficient design of CT, operation based on mfg. specifications. |
| 2014 | (2019) | Lon C Hill Power Sta, TX<br>(Siemens SCC6-5000 or GE 7FA) | 700 MW | 920 lb/MWh | Not listed |
| 2016 | (2019) | Southwestern Public Service Co. – Gaines Co. (SGT6-5000F5) | 1706 MW NGCC (Phase 2) | 960 lb/MWh (130.56 tons/hr during SU/SD) | |
| 2015 | (2020) | FGE Eagle Pines, TX<br>(GE 7HA.02) | 3450 MW | 886 lb/MWh<br>(excludes SU/SD, no duct firing)<br>8342 Btu/kWh<br>(excludes SU/SD, no duct firing)<br>816 lb/MWh<br>(excludes SU/SD, with duct firing)<br>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 | (2020) | CPV Fairview Energy Ctr, PA<br>(GE 7HA.02) | 1050 MW NGCC | 91 ppbvd @15% O2<br>(with or without duct firing)<br>847 lb/MWh gross<br>(no duct firing) | Low sulfur fuel and GCPs |
| 2015 | (2020) | NRG Texas Power, Bertron, TX<br>(GE 7HA (unit 5)) | 700 MW NGCC or NGSC | 825 lb/MWh<br>(excluding SU/SD & maintenance not to exceed 1 hour)<br>7054 Btu/kWh<br>(excluding SU/SD & maintenance not to exceed 1 hour)<br>179.95 tons/hr<br>(during MSS, no duct firing) | Thermal efficiency and natural gas/GCPs |
| 2015 | (2020) | NRG Cedar Bayou, TX<br>(GE 7HA (unit 5)) | 700 MW NGCC or NGSC | 825 lb/MWh<br>(excluding SU/SD & maintenance not to exceed 1 hour)<br>7054 Btu/kWh<br>(excluding SU/SD & maintenance not to exceed 1 hour)<br>179.95 tons/hr<br>(during MSS, no duct firing) | Thermal efficiency and natural gas/GCPs |
| 2013 | (2020) | Tyr Energy Hickory Run Energy Ctr, PA<br>(Siemens SGT-8000H) | 1000 MW NGCC | 928 lb/MWh gross | |
| 2014 | (2020) | CPV Pinecrest Energy Ctr, TX<br>(various turbine models proposed, the lowest emission rate is for the GE turbine w/o DB) | 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 | Energy efficiency, good design and combustion practices |
| 2012 | (2020) | Cricket Valley Energy Ctr, NY | 1100 MW NGCC | 7605 Btu/kWh (net HHV)<br>950 lb/MWh | Thermal Efficiency |
| 2014 | (2020) | FGE Power LLC, TX<br>(SGT6-5000F5ee) | 1442 MW NGCC | 7625 Btu/kWh net output (annual test)<br>889 lb/MWh w/or w/o duct burning (gross, no SSM) | Energy efficiency processes, practices, and design |
| 2016 | (2020) | Decordova II Pwr, TX<br>(GE 7FA or Siemens 5000F) | 800 MW NGCC | GE 932 lb/MWh<br>Siemens 966 lb/MWh | GCPs and low carbon fuel |
| 2016 | (2021) | Middlesex Energy, NJ<br>(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. |
| 2018 | (2021) | C4GT LLC, VA<br>(GE 7HA.02) | 1060 MW NGCC | 883 lb/MWh net HHV; 6745 Btu/kWh initial net HHV at full load, no DB, corrected to ISO | efficient power generation and the use of low carbon fuels |

| Permit Year | Startup Year* | Facility | Size/Type | GHG BACT limits | Basis |
|---|---|---|---|---|---|
| 2018 | (2021) | ESC Harrison Co Pwr, WV (GE7HA.02) | 640 MW NGCC | 826 lb/MWh gross (initial design, @52ºF, w/DB, base load) | Use of natural gas and GE technology |
| 2018 | (2021) | ESC Brooke Pwr, WV (GE7HA.01) | 940 MW NGCC | 829 lb/MWh gross (initial design, @52ºF, w/DB, base load) | Natural gas fuel and GE technology |
| 2013 | (2021) | LaPaloma Energy Ctr, TX | 735 MW | 942 lb/MWh<br>7679 Btu/kWh | Energy efficiency, good design and combustion practices |
| 2017 | (2021) | Killingly Energy Ctr, CT (SGT6-8000H) | 430 MW NGCC with oil backup | 816 lb/MWh (Initial test, net, ISO, no DB)<br>7273 Btu/kWh (net HHV, full load, no DB, 12-mo rolling avg) | Use of efficient power block, combined cycle technology, low emitting fuel |
| 2018 | (2021) | C4GT LLC, VA (SGT6-8000H) | 1060 MW NGCC | 883 lb/MWh net HHV; 6625 Btu/kWh initial net HHV at full load, no DB, corrected to ISO | efficient power generation and the use of low carbon fuels |
| 2016 | (2022) | Eagle Mtn Steam Elec, TX<br>(Siemens SGT6-5000F(5) or GE 7FA.05) | ~500 MW NGCC | GE 932 lb/MWh<br>Siemens 966 lb/MWh<br>7837 Btu/kWh gross | GCPs |
| 2014 | (2022) | Moundsville Power LLC WV (GE 7FA.04) | 631 MW NGCC plant | 793 lb/MWh (gross, baseline, no DB)<br>(59°F, evap. cooling on, baseload) | Low carbon fuel |
| 2018 | (2022) | Marshall Energy Ctr, North & South Plants, MI (H-class turbines) | 500 WW NGCC plants (each) | 806 lb/MWh, 12 mo-rolling avg.<br>1,978,297 TPY 12-mo rolling total | |
| 2013 | Not built yet | Midland Cogen, MI (GE) | 448 MW | 995 lb/MWh w/o DB<br>1071 lb/MWh w/DB (6% degradation) | Thermal efficiency and clean fuels. |

** Startup dates in Table 4 were taken from the US Energy Information Administration Preliminary Monthly Electric Generator Inventory which was updated in September 2018, 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 2013 for GHG, only 21 were constructed and operational as of December 2018. Of those 21 plants, only four MHPS M501G/J turbines 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 based on the following parameters are the lowest: fuel LHV, gross power output, ISO conditions, full load, and exclusion of SU/SD, duct-burning, and degradation. 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 Chickahominy Power, it was determined that the best measure of efficiency of the turbine would be the heat rate (Btu/kWh) using fuel HHV, at full load, corrected to ISO conditions. The facility is not proposing the use of duct burners so other BACT limits that include duct-firing are not comparable.

Degradation of a turbine’s efficiency is accepted as a result of normal operation. While degradation is considered for other pollutants in items such as capital recovery and catalyst replacement, GHG emissions are directly related to the mode of operation and the age of the equipment. Examples of items that affect turbine efficiency that warrant additional consideration with respect to GHG, include changes in surface roughness, changes in airfoil shape, and changes to energy leakage paths. These issues degrade the performance of the units and significantly affect the achievable GHG performance. However, degradation does not occur instantly upon commencing operation but occurs slowly over time.

Understanding the special GHG dynamics of efficiency degradation, a tiered approach to the degradation of the equipment has been utilized. While a single limit approach is acceptable and may be appropriate in many circumstances, it is not necessarily the only representation of a GHG BACT determination. Based on Chickahominy Power's knowledge of maintenance schedules for similar facilities, they proposed a six-year tier of limits. The plant's lifetime is 36 years or more, so degradation was factored over the foreseeable lifespan of this facility.

Tiered Heat Rate Limits (test conducted every five years at full load, corrected to ISO)

| Operating Period | Btu/kWh net (HHV) output |
|---|---|
| Initial test | 6,452 |
| Year 6 | 6,581 |
| Year 12 | 6,677 |
| Year 18 | 6,775 |
| Year 24 | 6,871 |
| Year 30 | 6,968 |
| Year 36 (and later) | 7,064 |

The most accepted way to show compliance with a heat rate limit based on full load, net HHV for fuel, and @ ISO conditions is to conduct a heat rate test of the power plant using ASME Performance Test Code on Overall Plant Performance (ASME PTC 46—1996) or equivalent. Actual operating data found at www.eia.gov will not show compliance with a heat rate limit based on net HHV, full load, no DB, @ISO. It will also not show compliance with a 12-month rolling average. It is raw data of reported fuel throughput and energy output summed for the months operated in a given year. The values can be used, however, to make general comparisons among operating units.

The lowest BACT heat rate limit in Table 4 is for the Dominion Greensville Power Station (VA) set at 6,457 Btu/kWh for a M501J turbine (net HHV, full load, no DB, corrected to ISO). This is an initial heat rate limit for the power plant. The facility started up in July of 2018 and testing was recently performed with the result of 6,300 Btu/kWh achieved. This facility also has a maximum, lifetime limit of 7,212 Btu/kWh. The C4GT Power Station (VA) has heat rate limits of 6,625 Btu/kWh for a SGT6-8000H turbine and 6,745 Btu/kWh for a GE 7HA.02 turbine (net HHV, at full load, corrected to ISO, no DB). These reflect initial limits for new turbines. The C4GT plant has not been constructed yet so its limits are not verified as being achievable. The next lowest, permitted, heat rate limit is for the CPV St. Charles (MD) facility with a limit of 7,109 Btu/kWh for a GE7FA.05 turbine (gross HHV @ISO, full load, no DB, over the lifetime of the plant). This plant has not been operating a full year yet, and it could not be verified if the facility had been tested and is in compliance with that limit (a gross heat limit would be less than a comparable net heat limit). The next lowest BACT limit is for the CPV Towantic (CT) plant, at 7,220 Btu/kWh for a GE7HA.01 turbine (HHV net, full load, on a 12-month rolling average over the lifetime of the plant). This plant started operation in mid-2018 and no heat rate test data has been obtained which can verify compliance with the permitted heat rate limit.

In addition to the heat rate limits mentioned above to measure efficiency, ongoing compliance with a GHG emission rate limit (in lb $CO_2e$/MWh) is also required for some plants. Compliance can be demonstrated by testing (for emission rates based on ISO conditions at full load) or by monitoring fuel consumption and power output (for limits based on a 12-month rolling average over all operating scenarios). The lowest BACT $CO_2e$ emission rates found in the RBLC and other sources are summarized in Table 5 below. As mentioned above, any information derived from the data found at www.eia.gov for operating power plants is not showing compliance with a permit limit. The lb $CO_2e$/MWh values were estimated based on emission factors found in EPA's

"Mandatory Reporting of Greenhouse Gases" FR Vol. 74, No. 209, Part 98 (October 2009) and they do not represent a 12-month rolling average. The values are only being used for comparison of actual operations of the turbines over the months operated, on a net basis, including all operations and loads.

Table 5 – Summary of lowest $CO_2e$ BACT emission rate limits from Table 4:

| Plant (permit year) | Turbine | Emission Rate Limits | Notes |
|---|---|---|---|
| Moundsville, WV (2014) not operating yet | GE7FA.04 | 793 lb/MWh | Gross, ISO, no DB, baseload operation |
| DTE Electric St. Clair, MI (2018) not operating yet | unknown | 794 lb/MWh | 12-mo rolling average |
| MEC North & South, MI (2018) not operating yet | H-class | 806 lb/MWh | 12-mo rolling average |
| CPV Towantic, CT (2015) operating mid-2018 | GE7HA.01 | 809 lb/MWh | Initial stack test only, net, ISO, no DB (achieving net 793 lb/MWh from Jan to Sept 2018 according to www.eia.gov) |
| Greensville Pwr Sta., VA (2016) operating mid-2018 | M501J | 812-890 lb/MWh | Initial to lifetime, net 12-mo rolling avg. over all operations. |
| Killingy, CT (2017) not operating yet | SGT-8000H | 816 lb/MWh | Initial stack test only, net, ISO, no DB |
| Salem Harbor, MA (2014) operating mid-2018 | GE 7F5 rapid response | 825 lb/MWh;<br><br>895 lb/MWh | full load, no DB, ISO<br><br>365 day-average over the lifetime of the plant (achieving net 881 lb/MWh from June to Sept 2018 according to www.eia.gov) |
| SR Bertron, TX (2015) not operating yet | GE7HA | 825 lb/MWh | 12-mo rolling average, excludes SU/SD |
| Cedar Bayou, TX (2015) not operating yet | GE7HA | 825 lb/MWh | 12-mo rolling average, excludes SU/SD |
| ESC Harrison Co Pwr, WV (2018) not operating yet | GE7HA.02 | 826 lb/MWh | Gross, initial design, @52ºF, w/DB, base load |
| ESC Brooke Pwr, WV (2018) not operating yet | GE7HA.01 | 829 lb/MWh | Gross, initial design, @52ºF, w/DB, base load |
| FPL Port Everglades, FL (2013) operating since 2016 | SGT6-8000H | 830 lb/MWh | 12-mo rolling average (achieving net 792 lb/MWh in 2017 according to www.eia.gov) |
| Oregon Clean Engy, OH (2013) operating since 2017 | SGT6-8000 | 833 lb/MWh | Gross (achieving 802 lb/MWh net in 2017 according to www.eia.gov) |
| Okeechobee Clean Engy, FL (2016) not operating yet | GE7HA.02 | 850 lb/MWh (NG)<br><br>1,000 lb/MWh | Does not include SU/SD<br><br>Including SU/SD and oil combustion |
| Dania Beach Engy, FL (2017) not operating yet | GE7HA | 850 lb/MWh (NG)<br><br>1,000 lb/MWh | Does not include SU/SD<br><br>Including SU/SD and oil combustion |
| Mattawoman Engy, MD (2015) not operating yet | SGT6-8000H v1.4 optimized | 865 lb/MWh | gross with or without duct firing, and includes SU/SD |
| Rockwood Engy Ctr, TX (2016) not operating yet | GE7HA.02 | 865 lb/MWh | HHV, includes all operations |
| Keys Engy Ctr, MD (2014) startup in mid-2018 | SGT6-5000Fee | 869 lb/MWh | gross w/ or w/o DB (achieving net 845 lb/MWh from Jan to Sept 2018 according to www.eia.gov) |
| CPV St. Charles, MD (2014) startup in 2017 | GE7FA.05 | 878 lb/MWh | RBLC entry but cannot be confirmed as a permit limit (achieving net 826 lb/kWh in 2017 according to www.eia.gov) |
| Colorado Bend II, TX (2015) startup in 2017 | GE7HA.02 | 879 lb/MWh | HHV gross, 12-mo rolling avg, excludes SU/SD (achieving net 777 lb/MWh in 2017 according to www.eia.gov) |
| C4GT, VA (2018) not operating yet | GE7HA.02 or SGT6-8000H | 883 lb/MWh | All operating conditions over the lifetime of the unit |
| York 2 Engy Ctr, PA (2015) startup late 2018? | GE7F.05 | 883 lb/MWh | w/DB |
| Montgomery Co, TX (2018) not operating yet | M501GAC | 884 lb/MWh | Gross, w/DB over lifetime of plant |
| FGE Eagle Pines, TX (2017) not operating yet | GE7HA.02 | 886 lb/MWh | ($CO_2$) No DB |

| Plant (permit year) | Turbine | Emission Rate Limits | Notes |
|---|---|---|---|
| Middlesex Engy Ctr, NJ (2016) not operating yet | GE7HA.02 | 888 lb/MWh | Gross, w/DB & some oil firing |
| FGE Power, TX (2014) not operating yet | SGT6-5000F5ee | 889 lb/MWh | Gross, 12-mo rolling avg, w/or w/o DB, across all operational loads |

As seen in Table 5, many of the permitted plants with the lowest $CO_2e$ emission rate limits are not operating yet, so compliance with the limits have not been verified. Additionally, many operating plants do not have 12 months of operating data. Chickahominy Power has proposed emission rate limits based on net power output, without DB, across all operations, on a 12-month rolling average. The only comparable limits that can be found are for the Greensville Power Station, FPL Port Everglades, Rockwood Energy Center, and C4GT. Of these, only FPL Port Everglades had a year's worth of operational data. The FPL Port Everglades permit limit of 830 lb/MWh for a SGT6-8000H turbine, includes operation at all loads, a 2% operational margin, and 5% degradation over time (according to a draft analysis). The data in www.eia.gov appears to show achievement of 792 lb/MWh net from January through December 2017 (not a 12-month average, which may be higher due to monthly variations). Data from other combined cycle facilities operating for 12 months in 2017 show a range in emission rate values from 769 lb/MWh to 834 lb/MWh. This may indicate that the compliance margin for the FPL plant, over the lifetime of the plant, may be very narrow and may not be achievable in the long-term.

Based on expected operations and degradation over the lifetime of the plant, Chickahominy Power has proposed the following tiered emission rates:

Tiered Emission Rate Limits (on a 12-month rolling average)

| Operational Year | Applicable limit in lb $CO_{2e}$/MWh net output |
|---|---|
| 1-6 | 812 |
| 7-12 | 824 |
| 13-18 | 836 |
| 19-24 | 847 |
| 25-30 | 859 |
| 31 (and later) | 871 |

Based upon its review of the application and comparable BACT determinations for recently-issued GHG PSD permits, DEQ concurs that the proposed heat rate limits and emission rate limits are representative of BACT for the proposed turbine models and their proposed operational configurations (three 1x1 blocks).

b. Auxiliary boilers and fuel gas heaters
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. Emergency generator and fire water pump
Add-on $CO_2$ controls are not technically feasible for emergency generators so BACT for the emergency generator and fire water pump will be GCPs and fuel-efficient design. 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 10 tons of methane/year from natural gas (equivalent to 250 tons of $CO_2$). Control techniques consist primarily of leak detection and repair, as well as prevention of leakage. Leak detection and repair includes inspecting

and testing to find leaks and then repairing them. Prevention includes minimizing venting, making sure connections are secure, and performing routine maintenance on the components. 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. Also, IR cameras that can detect volatile gasses such as methane are also technically feasible and available, albeit relatively expensive for a facility expected to have very minimal fugitive leaks. 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.[3] 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 low pressure detection system with alarm.

2. $NO_x$ Control

a. Combustion Turbines with duct-fired HRSG

i. Step 1 - Combustion turbines generate most of the $NO_x$ emissions from the facility. The following control technologies were identified by Chickahominy Power 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 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,

3 *$SF_6$ 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.

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 $NO_x$ 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 $NO_x$ 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. It can be shown to cause some flame instability and turbine vibration when employed on larger, gas-fired 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 Chickahominy Power 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 $NO_x$ 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
Chickahominy Power has proposed a combination of the top-ranked 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 Chickahominy Power. The draft permit proposes the additional use of SCR to control $NO_x$ emissions from the CTs to 2.0 ppmvd (at 15% $O_2$).

Compliance with the limit is to be based on a one-hour block average from a Continuous Emission Monitoring System (CEMS) and stack testing.

From 2013 to 2018, over 35 projects were permitted at 2.0 ppmvd at 15% $O_2$. No permits were issued with a lower limit. The proposed limits for the Chickahominy Power facility are as stringent as any listed in EPA's RACT/BACT/LAER Clearinghouse (RBLC) for electric generating facilities.

b. Auxiliary boilers and fuel gas heaters

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.
- SCR (approximately 82% efficient) with outlet temps around 700-750°F.

ii. Technical feasibility and availability of $NO_x$ Control
- Front- end $NO_x$ reduction technologies, as well as SCR, are available. However, SCR would not be maximized at the temperatures proposed for the boilers or fuel gas heaters (<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 only marginally feasible as a NOx reduction strategy for the auxiliary boilers and not technically feasible for the fuel gas heaters.

iii. Ranking of technologies
- SCR add-on technology might reach a $NO_x$ rate of 0.002 lb/MMBtu.
- 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

Chickahominy Power is proposing the use of front-end $NO_x$ reduction technologies. These technologies are efficient and do not create energy loss or adverse environmental impact. Tables 5-8 and 5-9 of their application evaluated the use of SCR for the boilers and the fuel gas heaters and that technology was found to be not cost-effective. It was estimated that SCR for the boilers was in excess of $54,000 per ton of $NO_x$ reduction and SCR for the fuel gas heaters was estimated to cost $209,000 per ton of reduction.

v. BACT determination
- A review of the RBLC shows recently-permitted natural gas-fired boilers and dew point/fuel gas heaters have $NO_x$ BACT limits between 0.01 and 0.013 lb/MMBtu (9 ppmvd) using LNB technology.
- DEQ concurs that LNB are BACT for both the auxiliary boilers and fuel gas heaters 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 or installations of multiple generators (i.e., data centers).
- The use of ULSD fuel, GCPs and limited hours of operation can control $NO_x$ emissions from internal combustion engines (ICE).

ii. Technical feasibility and availability of $NO_x$ Control (Step 2)

SCR, as well as the use of ULSD fuel, GCPs and limited hours of operation are all available and technically feasible.

iii. Ranking of technologies (Step 3)

The addition of SCR can reduce $NO_x$ emissions from diesel ICEs by 60-90%. The use of ULSD fuel and GCPs can result in $NO_x$ 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 $NO_x$ emissions.

iv. Evaluation of Step 3 controls (Step 4)
Although add-on controls such as SCR are used to control $NO_x$ on larger non-emergency generators or large installations (>10 MW) of multiple generators, if necessary, to meet national standards for emissions or avoid major-source permitting, BACT determinations for stand-alone, ULSD-fired, emergency, internal combustion engines do not include SCR. In 2010, the California Air Resources Board did an analysis on the technical feasibility and costs of after-treatment controls, such as particulate filters and SCR on new emergency standby engines (https://www.arb.ca.gov/regact/2010/atcm2010/atcmappb.pdf). The results indicated that, due to temperature and the operational considerations of most emergency generators (which were assumed to operate for 31 hours per year at about 30% load), such controls were not cost-effective (at approximately $56/lb of NOx removed). Chickahominy Power is proposing the use of ULSD fuel, GCPs and limited hours of operation to control $NO_x$ to 4.8 g/hp-hr (11.7 tons/year @ 500 hrs). These technologies are efficient and do not create energy loss or adverse environmental impact.

v. BACT determination (Step 5)
The lowest $NO_x$ BACT values in the RBLC for large diesel engines range from 0.5 g/bhp-hr (0.67 g/kW-hr) to 4.8 g/bhp-hr (6.4 g/kW-hr) using GCPs and ULSD. Add on controls like SCR are not required except for LAER and in the case of the installation of twelve 17 MW units at a gold mine in Alaska. The Cronus Chemical plant in Illinois proposed an emergency engine that could meet Tier 4 standards for non-road engines of 0.5 g/hp-hr (0.67 g/kW-hr) without add on controls. No cost analysis was done since the proposed limits were low, but it is not known if the facility was required to test the unit to verify compliance with that limit. A plant in Texas proposed a $NO_x$ limit of 5.43 g/kW-hr (4.0 g/bhp-hr) for a 4 MW generator based on Tier 2 standards from 40 CFR 89.112, but that plant never started up. Several units were permitted at 4.5 g/bhp-hr (6.0 g/kW-hr) at various nitrogen fertilizer plants in Indiana but no testing was required to show compliance with those limits. All other BACT limits were at 4.8 g/bhp-hr (6.4 g/kW-hr) or greater.

The lowest $NO_x$ BACT values in the RBLC for smaller diesel engines (primarily fire water pumps) range from 2.6 g/bhp-hr (3.5 g/kW-hr) to 3.0 g/bhp-hr (4.0 g/kW-hr) using GCPs and ULSD. As with the larger engines above, the Cronus plant proposed a fire water pump that could meet Tier 4 standards of 2.6 g/hp-hr (3.5 g/kW-hr) without add-on controls. No cost analysis was done and it is not known whether the unit was in compliance with those limits. The Alaskan gold mine installed three 252 hp fire pumps, each with limits for $NO_x$+NMHC of 2.8 g/bhp-hr (3.7 g/kW-hr) based on GCPs, clean fuels, and compliance with NSPS Subpart IIII. There is no mention in the permit analysis why the limit of 2.8 g/bhp-hr was used rather than the NSPS IIII limit for $NO_x$+NMHC of 3.0 g/bhp-hr. Similarly, two other plants, a nitrogen fertilizer plant in Iowa and a power plant in California, installed fire water pumps with $NO_x$ limits of 3.75 and 3.8 g/kW-hr respectively using GCP or limits on annual operation. Compliance with the fertilizer plant limit is based on certification from the manufacturer that the engine can meet NSPS Subpart IIII standards. For the fire water pump at the power plant, the $NO_x$ limit is based on the NSPS $NO_x$+ NMHC standard of 4.0 g/kW-hr with the assumption that the $NO_x$ portion would be 95% of that standard (0.95 x 4.0 = 3.8). All other limits for small diesel engines are 3.0 g/bhp-hr (4.0 g/kW-hr) or more.

Chickahominy proposes $NO_x$ BACT for the 3000 kW diesel emergency generator (EG-1) and 376 hp diesel fire water pump (FWP-1) to be ULSD fuel and GCPs. The manufacturer of EG-1 certifies the unit to meet a $NO_x$ limits of 4.8 g/bhp-hr. and the FWP-1 is certified to meet a $NO_x$ limit of 3.0 g/bhp-hr.

The facility must demonstrate compliance with the NSPS standards, while also meeting the BACT $NO_x$ emission limit for each generator. 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 (OxCat)
         - GCPs

      ii. Available and feasible (Step 2)
      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.

GCPs are used to minimize the formation of CO. GCPs 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 GCPs to control the formation of CO, and OxCat as a post-combustion treatment.

iv. Evaluation of Step 3 controls (Step 4)
Chickahominy Power has proposed the top-ranked option (a combination of control options for CO: OxCat and GCPs) 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 GCPs and OxCat in the most recent BACT determinations in the RBLC or in permits reviewed for this permit action are presented in Table 6 below.

Table 6 – RBLC data for CO emissions from Natural Gas fired Combustion Turbines

| Facility | Turbine & permit date | Limit w/o DB | Description |
|---|---|---|---|
| Kleen Energy Systems, CT | SGT6-5000F February 2008 | 0.9 ppmvd | At full load, excluding SU/SD, maintenance |
| CPV Towantic Energy Center, CT | GE 7HA.01 November 2015 | 0.9 ppmvd | At full load excluding SU/SD, maintenance |
| West Deptford Energy Center, NJ | SGT6-5000F (Phase II) July 2014 | 0.9 ppmvd | At full load excluding SU/SD, maintenance |
| Dominion Greensville Power Sta, VA | M501J June 2016 | 1.0 ppmvd | Across all loads excluding SU/SD, maintenance |
| Killingly Energy Ctr, CT | SGT6-8000H June 2017 | 0.9 ppmvd | Across all loads, excluding SU/SD, maintenance |
| C4GT, VA | GE 7HA.02 March 2018 | 1.0 ppmvd | Across all loads, excluding SU/SD, maintenance |

Of these facilities the Kleen Energy Systems plant has been operating since 2011. 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.

CPV Towantic's limit only applies at full load, as does the limit for the West Deptford Energy Center, so these limits are not comparable to the Chickahominy limit.

The Killingly Energy Center CO limit of 0.9 ppmvd is across all loads and excludes non-steady-state operation (i.e., SU/SD and maintenance activities) so this is comparable to Chickahominy Power. Compliance with this limit is based on a 1-hour average from CEMS data, which is more stringent that the 3-hour averaging time for Chickahominy. This facility has not begun operation, however, so the limit has not been demonstrated.

The Dominion Greensville turbines are M501J models. These are the same turbine models proposed for the Chickahominy Power station. The limits proposed for these turbines apply at all loads, on a 3-hour rolling average, without duct burning. This is also comparable to the operation proposed by Chickahominy Power. The Dominion Greensville plant was tested in November 2018 and was found to be in compliance with their CO limit (at baseload with no DB).

Other than the facilities in Table 6, CO limits in recently issued permits for similar facilities are greater than or equal to 1.5 ppmvd with or without duct burning.

The proposed CO limits for the Chickahominy Power turbines are as follows:

| Turbine | Limit | Description |
|---|---|---|
| M105JAC | 1.0 ppmvd | Applies across all loads. Excludes SU/SD and maintenance. |

Compliance with the limits is to be based on a three-hour rolling average. This is different from 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 Chickahominy Power (similar to the Dominion Greensville permit and C4GT limit), 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 GCPs, constitute BACT for CO (3-hour rolling average) from the CTs.

b. Auxiliary boilers and fuel gas heaters

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

ii. Technical feasibility and availability of CO Control (Step 2)
- GCPs are feasible and available for these units
- OxCat is technically feasible and available for the auxiliary boilers but, due to the small size of the fuel gas heaters (12 MMBtu), OxCat is not technically feasible for those units.

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

iv. Evaluation of controls in Step 3 (Step 4)

- GCPs do 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 (under 100 MMBtu/hr rated capacity):

Table 7 - Oxidation catalyst for CO control from auxiliary boilers

| | Size | |
|---|---|---|
| Footprint Power Salem, MA (State BACT) started up mid-2018 | 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) |

The Footprint Salem plant started operation in mid-2018. The limit in the permit represents State BACT (not PSD BACT). It is not known if stack testing has demonstrated that the limit is achievable. 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 0.045 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 GCPs. 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 GCPs, which is quite a bit higher than that proposed for Chickahominy Power’s fuel gas heaters.

Several facilities have auxiliary boilers permitted at 0.036 lb/MMBtu for CO but those units are smaller (<50 MMBtu/hr).

CPV Fairview (CT) and Moxie Freedom (PA) received BACT permit limits for natural gas-fired auxiliary boilers of 0.037 lb/MMBtu using GCPs. The 40 MMBtu/hr boiler at Troutdale (OR) has a BACT limit of 0.04 lb/MMBtu using GCPs. Other, similar boilers permitted in the last five years have limits greater than 0.04 lb/MMBtu.

The Mattawoman Energy Center (MD) has a permit limit for a 13.8 MMBtu/hr fuel gas heater of 0.021 lb/MMBtu based on GCPs. This was developed from a vendor guaranteed emission rate but no other information was available. Testing is not required to show compliance with this emission rate. Other RBLC CO limits for fuel gas heaters are listed as 0.037 lb/MMBtu or higher.

- Oxidation catalyst used in conjunction with GCPs could reduce CO emissions from the Chickahominy Power auxiliary boilers by 7.1 tons/yr (each GE Boiler) or 11.4 TPY (each MHPS Boiler) at a cost of $12,300 per ton (each GE Boiler) or $8,300 (each MHPS Boiler). The fuel gas heaters’ CO emissions would be reduced by

2.1 tons/yr (each) at a cost effectiveness of $44,500 per ton, making OxCat economically infeasible for both the boilers and the fuel gas heaters.

- Chickahominy Power proposed a rate of 0.037 lb/MMBtu based on vendor-supplied factors. DEQ has determined that GCPs are BACT for CO to a level of 0.037 lb/MMBtu for the auxiliary boilers (B-1, B-2) and fuel gas heaters (FGH-1, FGH-2, FGH-3).

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 Chickahominy Power. DEQ concurs with the proposed use of pipeline quality natural gas to achieve the following BACT rates for the combustion turbines (these limits apply at all times):

- 0.00120 lb/MMBtu

b. Auxiliary boiler and fuel gas heater
The only feasible control for $H_2SO_4$ from the auxiliary boiler and fuel gas 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 fuel gas 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

- GCPs

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.

GCPs 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 GCPs to control the formation of VOC, and oxidation catalyst as a post-combustion treatment.

iv. Evaluation of Step 3 technologies (Step 4)
GCPs 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 (2013 to present) combined-cycle facilities <u>without duct burning</u> are in the range of 0.7 ppmvd at 15% $O_2$ to 1.5 ppmvd at 15% $O_2$. Chickahominy Power's proposed VOC limits include all operational loads and excludes SU/SD.

The applicant has proposed to control VOC using GCPs 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 proposed VOC limits for the Chickahominy Power turbines are as follows:

| Turbine | Limit | Description |
|---|---|---|
| M105JAC | 0.7 ppmvd | Applies across all loads. Excludes SU/SD and maintenance. |

DEQ concurs that the use of GCPs and an oxidation catalyst represent BACT for VOC control for the proposed Chickahominy Power combustion turbines and their operational configurations.

b. <u>Auxiliary boiler and fuel gas heater</u>

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

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

iii. Ranking of technologies (Step 3)
- Oxidation catalyst used in conjunction with GCPs would achieve the best VOC control rate for the auxiliary boiler.
- GCPs 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%). As mentioned in the BACT discussion for CO, OxCat is only being implemented on auxiliary boilers at two facilities: Salem Harbor and IPL Marshalltown. In both cases, the OxCat has only been shown to control the CO from these units. VOC emissions were not considered to be controlled to any great extent by OxCat and so those units emission limits did not include OxCat as BACT for VOC from the auxiliary boilers.

GCPs 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, in the past five years, only two facilities have been given BACT VOC limits below 0.005 lb/MMBtu using GCPs on an auxiliary boiler less than 100 MMBtu/hr heat input (some lower determinations were LAER). The 61.5 MMBtu/hr auxiliary boilers at the Marshall Energy Center North Plant and South Plant (MI) have permit limits of 0.004 lb/MMBtu but those units have not been constructed yet.

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

GCPs results in VOC emissions that are consistent with BACT at similar facilities at 0.005 lb/MMBtu. DEQ concurs with Chickahominy Power that GCPs are BACT for VOC from the auxiliary boilers and fuel gas heaters.

c. <u>Emergency generator and fire water pump</u>
The use of GCPs and limiting operation to 500 hrs/yr are considered BACT for VOC from the emergency units. The manufacturer of EG-1 certifies the unit can meet a VOC limit of 1.0 g/bhp-hr and the FWP-1 is certified to meet a VOC limit of 0.11 g/bhp-hr proposed as BACT. The facility must demonstrate compliance with the NSPS standards, while also meeting the BACT VOC emission limit for each generator. This is consistent with the RBLC.

d. <u>Fuel Tank</u>
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 while $PM_{10}$ 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 scenario unique to the configurations of each model of turbine.

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 GCPs 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 GCPs. 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 $PM_{2.5}$; 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. Additionally, size of the turbines, configuration of the turbines (eg., 3 on 1, 1 on 1), stack parameters, ambient conditions and other factors also contribute to the variability of permit limits.

Turbine data provided to Chickahominy Power from the turbine vendor showed that there was no change in the $PM_{10}$ and $PM_{2.5}$ emissions due to load for the MHPS turbines.

The proposed PM, $PM_{10}$ and $PM_{2.5}$ BACT limits for the Chickahominy Power turbines include operation at all loads and include SU/SD, but exclude tuning. 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 Chickahominy Power 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, without duct burning. 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.

Table 8 – Comparison of **$PM_{10}$** values at full load with no DB, from low to high in terms of lb/MMBtu for units permitted since 2013.

| Facility | Turbine & size | Pollutant | Permit Limit(s) | BACT |
|---|---|---|---|---|
| Dominion Greensville, VA (6/17/16)<br>Startup July 2018 | M501J<br>CT only<br>3,227 MMBtu/hr | $PM_{10}$, $PM_{2.5}$ | 9.2 lb/hr<br>0.0030 lb/MMBtu (average of 3 test runs). Limits exclude SU/SD | Pipeline quality NG, GCPs, low sulfur/low carbon fuel (0.4 gr/100 dscf) |
| Dominion Brunswick, VA<br>(3/12/13)<br>Startup 2016 | M501GAC<br>CT only<br>2,941 MMBtu/hr | $PM_{10}$ & $PM_{2.5}$ | 9.7 lb/hr<br>0.0033 lb/MMBtu excludes SU/SD (in compliance with limits) | GCPs and low sulfur/low carbon fuel (0.4 gr/100 dscf) |
| Green Energy Partners Stonewall, VA<br>(4/30/13, 7/15/14)<br>Startup 2016. | SGT6-5000F5<br>2,314 MMBtu/hr | $PM_{10}$ & $PM_{2.5}$ | 10.1 lb/hr<br>0.00374 lb/MMBtu at full load (in compliance with limits) | GCPs and pipeline quality NG (0.1 gr/100 dscf max), 3-hr average. Excludes SU/SD. |
| CPV Towantic, CT<br>(11/30/15)<br>Startup 2018 | GE7HA.01<br>CT only<br>2,511 MMBtu/hr | Emissions assumed to be all $PM_{2.5}$ | 9.7 lb/hr<br>0.0041 lb/MMBtu At full load/steady state (sulfur content of NG 0.5 gr/100 dscf) | GCPs, NG |
| APV Renaissance Energy Ctr, MI<br>(7/19/18)<br>Not constructed | SGT6-8000H<br>3,580 MMBtu/hr LHV | PM filt, $PM_{10}$, $PM_{2.5}$ | Not in RBLC yet | GCPs |
| West Deptford, NJ Phase II expansion (7/18/14) Not constructed yet. | MHPS or GE<br>F class<br>CT only<br>2,276 MMBtu/hr | PM filt<br>$PM_{10}$&$PM_{2.5}$ | 6.0 lb/hr<br>10 lb/hr (0.005 lb/MMBtu HHV @ full load, 59 degrees | NG as fuel |
| Stonegate Middlesex Energy, NJ (7/19/16)<br>Planned startup 2021 | GE 7HA.02<br>CT only<br>3,462 MMBtu/hr | PM filt<br>$PM_{10}$&$PM_{2.5}$ | 4.4 lb/hr<br>11.7 lb/hr | NG, clean fuel (sulfur content of 0.47 gr/100 scf) |
| Killingly Energy Ctr, CT (6/30/17)<br>Not constructed yet | SGT6-8000H<br>CT only<br>2,969 MMBtu/hr | $PM_{10}$, $PM_{2.5}$ | 13.0 lb/hr<br>0.0044 lb/MMBtu Steady state operation (sulfur content of natural gas 0.0016% by weight). | GCPs |
| PSEG Fossil Sewaren, NJ<br>(3/7/14 & 3/10/16)<br>Startup 2018 | GE7HA.02 Unit 7<br>CT only<br>3,311 MMBtu/hr | PM filt<br>$PM_{10}$, $PM_{2.5}$ | 4.7 lb/hr<br>14.4 lb/hr Excludes SU/SD. | NG, clean fuel (sulfur content of NG 0.75 gr/100 dscf). |
| Oregon Clean Energy, OH<br>(6/18/13)<br>Startup 2017 | SGT-8000H<br>CT only<br>2,932 MMBtu/hr | $PM_{10}$&$PM_{2.5}$ | 13.3 lb/hr<br>0.0047 lb/MMBtu Steady state/full load ISO. | NG & Clean fuel (sulfur content of NG 0.5 gr/100 dscf) |

| Facility | Turbine & size | Pollutant | Permit Limit(s) | BACT |
|---|---|---|---|---|
| Moxie Freedom, PA (9/1/15) Planned startup late 2018 | GE7HA.02 3,327 MMBtu/hr | PM filt, $PM_{10}$, $PM_{2.5}$ | 11.7 lb/hr 0.0063 lb/MMBtu excludes SU/SD (sulfur content of NG 0.4 gr/100 dscf monthly avg) | Low sulfur fuel & GCPs. |
| C4GT, VA (4/26/18) Not constructed | SGT6-8000H 3,116 MMBtu/hr GE7HA.02 3,482 MMBtu/hr | $PM_{10}$ & $PM_{2.5}$ $PM_{10}$ & $PM_{2.5}$ | 0.0065 lb/MMBtu 0.0068 lb/MMBtu | GCPs, pipeline NG S=0.4 gr/100scf |
| TES Filer City, MI (11/17/17) Planned startup mid-2020 | CT 1,934 MMBtu/hr | PM filt $PM_{10}$&$PM_{2.5}$ | 0.0025 lb/MMBtu 0.0066 lb/MMBtu | GCPs, pipeline NG, inlet filter |
| Calpine York (2) Energy Ctr, PA (6/15/15) Startup 2018 | GE 7F.05 CT only 2,513 MMBtu/hr | PM, $PM_{10}$, $PM_{2.5}$ | 0.0068 lb/MMBtu | GCPs and low sulfur fuel |
| CPV Fairview, PA (9/2/16) Planned startup 2020 | GE7HA.02 CT only 3,338 MMBtu/hr | PM tot, $PM_{10}$, $PM_{2.5}$ | 0.0068 lb/MMBtu excludes SU/SD | Low sulfur fuel, GCPs |
| Footprint Salem Harbor, MA (1/30/14) Startup 2018 | GE7F.05 CT only 2,300 MMBtu/hr | $PM_{10}$, $PM_{2.5}$ | 8.8 lb/hr 0.0071 lb/MMBtu (1-hr avg) , At loads above 75%, excludes SU/SD (sulfur content of NG 0.5 gr/100 dscf) | GCPs |
| Mattawoman Energy Ctr, MD 990 MW (11/13/15) Planned startup 2020 | SGT6-8000H 1.4 optimized 2,988 MMBtu/hr | PM filt<br><br>$PM_{10}$,$PM_{2.5}$ | 8.9 lb/hr (100% load) 0.00395 lb/MMBtu (<50% load) 17.9 lb/hr (100% load) 0.0079 lb/MMBtu (<50% load) (Limits include 10% margin over vendor estimate) Limits apply at all times (max short term sulfur content 1.0 gr/100 dscf; annual average 0.25 gr/100 dscf). | Pipeline quality NG, GCPs Testing done at >90% load with DB. |
| ODEC Wildcat Pt, MD (1,000 MW) (4/8/14) Startup 2017 | M501GAC 3,200 MMBtu/hr | PM filt<br><br>$PM_{10}$ & $PM_{2.5}$ | 15.0 lb/hr (0.0047 lb/MMBtu) 25.1 lb/hr (0.0079 lb/MMBtu) Limits based on 100% load & at -14ºF and an annual avg sulfur content of 0.75 gr/100 dscf | Pipeline NG and efficient design |
| CPV St. Charles, MD (4/23/14) Startup 2017 | GE7FA.05 2,308 MMBtu/hr | PM filt $PM_{10}$, $PM_{2.5}$ | 0.005 lb/MMBtu 0.008 lb/MMBtu | Pipeline quality NG (0.25 gr S/100scf) & GCPs |
| Midland Cogen Venture, MI (448 MW expansion) (4/23/13) Never executed | CT only 2,237 MMBtu/hr | PM tot $PM_{10}$ & $PM_{2.5}$ | 0.006 lb/MMBtu 23.4 lb/hr 0.012 lb/MMBtu includes SU/SD. | GCPs (add-on controls economically infeasible |

Of the 20 permitted facilities listed in Table 8 above, 11 of them have started operations and so the limits are presumably demonstrable:

- The Brunswick and Greensville Dominion plants are Mitsubishi turbines operating in Virginia and were permitted as baseload plants with minimal operation at low load (<50%). The limits do not include periods of SU/SD (instead, limits on the duration of each alternative operation were included in the permit). Stack testing has shown that the Brunswick plant is in compliance with its $PM_{10}$ and $PM_{2.5}$ limits at full load.

- The Stonewall plant in Virginia installed Siemens turbines combusting natural gas with a limit on sulfur content of only 0.1 gr/100scf (a prime basis for PM emissions) and the limits represent full load. Stack testing has shown that the plant is in compliance with its $PM_{10}$ and $PM_{2.5}$ limits at full load.
- CPV Towantic limits are for a GE7HA.01 turbine and are based on full load and steady state operation.
- PSEG Sewaren limits for a GE7HA.02 turbine exclude SU/SD.
- Oregon Clean Energy limits for a Siemens turbine apply during full load, steady state, ISO conditions.
- Moxie Freedom is permitted for GE7HA.02 turbines burning natural gas with a 0.4 gr/100scf sulfur limit, but the emission limits exclude SU/SD.
- The Calpine York 2 Energy Center is permitted for a GE F class turbine. The limits apply at all times.
- Footprint Salem Harbor is also permitted for a GE F class turbine. The limits apply to loads above 75%.
- ODEC Wildcat Pt is permitted for a Mitsubishis turbine and the limits reflect worst-case operations. The sulfur content of the natural gas is limited to an annual average of 0.75 gr/100 scf.
- CPV St. Charles is permitted for a GE F class turbine and includes a limit for sulfur content of the natural gas to 0.25 gr/100 scf

Chickahominy Power proposes the use of GCPs and the use of NG with an average annual sulfur content of 0.4 gr/100 scf for the combustion turbines at the following BACT rates for PM, $PM_{10}$ and $PM_{2.5}$ (<u>which apply at all times except during tuning</u>):

| Turbine & size | Pollutant | Permit Limit(s) | BACT |
|---|---|---|---|
| M501JAC<br>4,070 MMBtu/hr | PM filt<br>$PM_{10}$ & $PM_{2.5}$ | 0.0052 lb/MMBtu<br>12.3 lb/hr | GCPs, the use of pipeline-quality natural gas, w/maximum sulfur content of 0.4 grains per 100 scf, on a 12-month rolling average. |

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. The $PM_{10}$ and $PM_{2.5}$ limits (12.3 lb/hr) apply at all loads and temperatures.

Worst case PM, $PM_{10}$ and $PM_{2.5}$ permit limits in terms of lb/MMBtu are included for BACT demonstration (by stack testing). The PM, $PM_{10}$ and $PM_{2.5}$ limits for the turbines (0.0052 lb/MMBtu) were estimated at 55% load, @99°F, and 46% relative humidity.

Filterable PM limits are included for BACT demonstration only (there is no NAAQS for filterable PM) and so only a lb/MMBtu limit is included in the permit.

DEQ agrees that these limits represent BACT for the operational configurations of the Chickahominy turbines.

b. <u>Auxiliary boilers and fuel gas heaters</u>
Particulate matter emissions from the boilers and fuel gas heaters are a combination of filterable and condensable particulate. GCPs and limiting fuel use to only pipeline quality natural gas are proposed by the applicant as BACT for PM, $PM_{10}$ and $PM_{2.5}$ emissions from the auxiliary boilers and fuel gas heaters. 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 boilers and heaters.

Table 9 – RBLC PM determinations for similar boilers (40-99 MMBtu/hr) from lowest to highest on a lb/MMBtu basis for $PM_{10}$ or $PM_{2.5}$ (Limit values in parentheses are estimated based on lb/hr limit and heat rating of unit in MMBtu/hr).

| Facility | Equipment | Pollutant | Limit | BACT |
|---|---|---|---|---|
| Salem Harbor, MA 1/30/14. Startup 2018 | Aux Boiler 80 MMBtuhr | $PM_{10}$, $PM_{2.5}$ | 0.005 lb/MMBtu 0.4 lb/hr | Excludes SU/SD (0.5 gr S /100 dscf) |
| CPV St. Charles, MD (4/23/14) Startup 2017 | Aux boiler 93 MMBtu/hr | PM filt, $PM_{10}$, $PM_{2.5}$ | 0.005 lb/MMBtu | Pipeline quality NG (0.25 gr S/100 scf) & GCPs |
| Renaissance Pwr, MI (11/1/13), Phase II not constructed yet | Aux Boiler 40 MMBtu/hr | PM tot, $PM_{10}$, $PM_{2.5}$ | 0.005 lb/MMBtu | GCPs |
| Tyr Hickory Run, PA (4/23/13) Planned startup 2020 | Aux Boiler 40 MMBtu/hr | PM tot | 0.005 lb/MMBtu | GCPs |
| York Energy, PA 6/15/15 | Aux boiler 61 MMBtu/hr | PM tot, $PM_{10}$, $PM_{2.5}$ | 0.005 lb/MMBtu | GCPs and low S fuel |
| Marshall Energy Ctr., N&S plants, MI (6/29/18) | Aux Boiler 61.5 MMBtu/hr | PM filt $PM_{10}$, $PM_{2.5}$ | 0.005 lb/MMBtu 0.46 lb/hr (0.0075 lb/MMBtu) | GCPs |
| Holland Engy Ctr, MI (12/5/16) | Aux Boiler 83.5 MMBtu/hr | $PM_{10}$, $PM_{2.5}$ | 0.007 lb/MMBtu | GCPs |
| Belle River, MI (7/16/18) | Aux Boiler 99.9 MMBtu/hr | PM filt, $PM_{10}$, $PM_{2.5}$ | 0.007 lb/MMBtu | GCPs |
| CPV Fairview, PA (9/2/16) | Aux Boiler 92.4 MMBtu/hr | PM filt, $PM_{10}$, $PM_{2.5}$ | 0.007 lb/MMBtu | GCPs |
| Moxie Freedom, PA (9/1/15) | Aux Boiler 55.4 MMBtu/hr | PM tot, $PM_{10}$, $PM_{2.5}$ | 0.007 lb/MMBtu | NG/LPG, Good Eng. Practices |
| Dominion Brunswick, VA (3/12/13) | Aux Boiler 66.7 MMBtu/hr | $PM_{10}$, $PM_{2.5}$ | 0.007 lb/MMBtu | NG/GCPs |

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 $tot_t$, $PM_{10}$, $PM_{2.5}$ | 0.007 lb/MMBtu | Not stated |
| Lackawanna, PA 12/23/15; 7/12/16 | FGH 12 MMBtu/hr | PM $filt_t$, $PM_{10}$, $PM_{2.5}$ | 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 |
| Dominion Greensville, VA 6/17/16 | FGH 7.8 MMBtu/hr | $PM_{10}$, $PM_{2.5}$ | 0.007 lb/MMBtu | GCPs & pipeline NG (0.4 gr/100 scf S) |
| | FGH 16.1 MMBtu/hr | $PM_{10}$, $PM_{2.5}$ | 0.007 lb/MMBtu | GCPs & 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 | GCPs & 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) | GCPs & 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) | GCPs |
| Wildcat Pt, MD 4/8/14 | DPH 5 MMBtu/hr | PM, $PM_{10}$, $PM_{2.5}$ | 0.0075 lb/MMBtu | GCPs & pipeline NG |
| Mattawoman, MD 11/13/15 | FGH 13.8 MMBtu/hr | PM, $PM_{10}$, $PM_{2.5}$ | 0.0019 lb/MMBtu 0.0075 lb/MMBtu | GCPs & pipeline NG |
| Holland, MI 2/5/16 | Fuel preheater 3.7 MMBtu/hr | PM, $PM_{10}$, $PM_{2.5}$ | 0.007 lb/MMBtu 0.0075 lb/MMBtu | GCPs |
| 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/fuel gas heaters (see Table 9 and Table 10) show PM limits ranging from 0.005 lb/MMBtu to 0.007 lb/MMBtu for Auxiliary Boilers.

A reduction in emissions for the proposed auxiliary boilers B-1 and B-2 from 0.007 lb/MMBtu to 0.005 lb/MMBtu would result in a reduction of less than one ton of PM annually for each unit.

There are no fuel gas/fuel gas heaters in the RBLC that have limits less than 0.007 lb/MMBtu for $PM_{10}$ or $PM_{2.5}$ emissions. There are two entries in the RBLC for PM emissions at 0.002 lb/MMBtu.

The FGHs proposed for Chickahominy Power are 12 MMBtu/hr in size. The achievement of 0.002 lb/MMBtu down from 0.007 lb/MMBtu would be a reduction of about 0.25 tons/year for filterable PM from each unit, if they were run continuously (8760 hrs/year).

Short-term PM, $PM_{10}$ and $PM_{2.5}$ emissions from the auxiliary boilers and fuel gas heater will be limited to 0.007 lbs/MMBtu.

c. Fire pump and emergency generator

Possible PM controls for an emergency generator consist of the following: catalysts, diesel particulate filters, clean fuels and GCPs. Of these, catalysts are not used for units that are only run on an as-needed basis, making them not technically feasible for these units.

Diesel particulate filters have been used on heavy duty and non-road engines that are operated frequently. They may be able to remove 30-90% of filterable PM and may help older units to comply with lower emission standards. Only two facilities have required a diesel particulate filter as BACT for emergency generators and fire water pumps (Marshall Energy Center North and South plants in Michigan, issued June 2018), but the PM limit for those units is at least 0.15 g/hp-hr, which is not any less than units not required to use the filters. This facility is not constructed yet.

PM, $PM_{10}$ and $PM_{2.5}$ BACT for emergency diesel engines and fire water pumps is almost exclusively the use of ultra low sulfur diesel (ULSD) fuel with a sulfur content of no more than 15 ppm, and GCPs. Chickahominy has proposed this as BACT for emergency units and DEQ concurs.

The RBLC shows about eight emergency generators and fire water pumps with PM emission limits less than 0.15 g/hp-hr (0.2 g/kW-hr). These limits range from 0.025 g/hp-hr to 0.11 g/hp-hr (and 0.02 g/kw-hr to 0.15 g/kw-hr). The description of BACT for these units is no different from any other unit in the RBLC, i.e., GCPs and ULSD fuel, so the bases for these limits can only be assumed to be a vendor guarantee of some kind. The respective vendors for the Chickahominy generators have certified those units to meet PM, $PM_{10}$, and $PM_{2.5}$ emission levels of 0.15 g/hp-hr.

BACT limits for the Emergency Units at Chickahominy Power

| Unit | 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 |

7. Emissions during 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 are also not operating at their highest output and other emissions may be reduced for that reason. Chickahominy Power 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. GCPs include controlling the fuel/air mixing, temperature, and gas residence time during combustion to

minimize emissions. Chickahominy Power submitted BACT for SU/SD for the turbines as follows (alternative limits during SU/SD, as applicable, can be found in the BACT Summary Table 11 below):

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

b. $NO_x$ - Technically feasible $NO_x$ controls during SU/SD include SCR, DLN, and GCPs. Of these, SCR is most effective, followed by GCPs and DLN. A combination of these controls will be employed to minimize $NO_x$ 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 GCPs. Of these, oxidation catalyst is most effective, followed by GCPs 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. Chickahominy Power 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 $PM_{2.5}$ – No alternate BACT was proposed since the PM limits for the turbines include minimal emissions from SU/SD.

8. Alternative Operating Scenarios (maintenance events):

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 $NO_x$ controls during tuning include SCR, DLN, and GCPs. Of these, SCR is most effective, followed by GCPs and DLN. A combination of these controls will be employed to minimize $NO_x$ during tuning. $NO_x$ from the turbines will be limited to 703 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 GCPs. Of these, oxidation catalyst is most effective, followed by GCPs and DLN. A combination of these controls will be employed to minimize CO during tuning. CO from the MHPS turbines will be limited to 214 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. Chickahominy Power 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 GCPs. Chickahominy Power also proposes limitations on the duration of tuning events to minimize annual PM emissions from tuning.

vii. The total number of hours allowed by the permit for tuning events is 96 hours per turbine per year, calculated monthly as the sum of each consecutive 12-month period.

Table 11 – Summary of BACT for the facility:

| Pollutant | Equipment and Primary BACT | Control | Compliance |
|---|---|---|---|
| $CO_2e$ | Turbines<br>Initial emission limit for $CO_2e$:<br>**812** lb/MWh annual average<br><br>Initial heat rate limit:<br>**6,452** Btu/kWh net HHV at full load, ISO conditions | Energy efficient combustion practices and low GHG fuels | Fuel monitoring<br>Power output monitoring<br>Initial heat rate evaluation<br>ASME Performance Test Code on Overall Plant Performance (PTC 46) |
| $CO_2e$ | Auxiliary boilers and fuel gas heaters | GCPs, clean fuel (NG), and efficient design. | Manufacturer specifications and maintenance. |
| $CO_2e$ | Emergency Generators | High efficiency operation and limit on annual hours of operation | Fuel usage monitoring |
| $CO_2e$ | Electrical Circuit breakers<br>0.5% leakage rate | Enclosed-pressure type breaker and leak detection | Audible alarm with decreased pressure. |
| $CO_2e$ | Fugitive leaks from natural gas piping components | AVO monitoring and leak repair | recordkeeping |
| $NO_x$ | Turbines<br>This limit applies at all times except SU/SD and maintenance events:<br>2.0 ppmvd @ 15% $O_2$ (1-hour avg.)<br><br>Average for each event<br>Cold start: 60 lb/turbine<br>Warm start: 54 lb/turbine<br>Hot start: 42 lb/turbine<br>shutdown: 20 lb/turbine<br><br>Limits during tuning<br>703 lb/turbine/calendar day | Dry Low NOx burners<br>SCR | Annual fuel throughput or NOx CEMS<br>Stack test<br><br>Annual limit for tuning events |
| $NO_x$ | Auxiliary Boilers (each)<br>0.6 lb/hr (0.011 lbs/MMBtu)<br><br>Fuel gas heaters<br>0.011 lb/MMBtu (9 ppmvd @ 3% $O_2$) | Natural gas combustion with dry low NOx burners | Annual fuel throughput or NOx CEMS<br>Stack test |
| $NO_x$ | Emergency Generators<br>EG-1 4.8 g/bhp-hr<br>FWP-1 2.6 g/bhp-hr | GCPs | Annual hours of operation |
| CO | Turbines<br>This limit applies at all times except SU/SD and maintenance events:<br>1.0 ppmvd @15% $O_2$ (3-hour avg)<br><br>Limits during SU/SD<br>average for each event<br>Cold start: 444 lb/turbine<br>Warm start: 396 lb/turbine<br>Hot start: 252 lb/turbine<br>shutdown: 156 lb/turbine<br><br>Limits during tuning<br>214 lb/turbine/calendar day | Oxidation catalyst<br>GCPs | CO CEMS<br><br>Annual limit for tuning events |

<table>
<tr><th>Pollutant</th><th>Equipment and Primary BACT</th><th>Control</th><th>Compliance</th></tr>
<tr><td>CO</td><td>Auxiliary Boilers (each)<br>3.2 lb/hr (0.037 lbs/MMBtu)<br><br>Fuel gas heaters<br>0.5 lb/hr (0.037 lb/MMBtu)</td><td>Clean fuel and GCPs</td><td>Stack test</td></tr>
<tr><td>CO</td><td>Emergency generators<br>2.6 g/hp-hr</td><td>Proper operation and maintenance, clean fuel</td><td>Annual hours of operation</td></tr>
<tr><td>VOC</td><td>Turbines<br>This limit applies at all times except SU/SD and maintenance events:<br>0.7 ppmvd @15% $O_2$ (3-hour avg)<br><br>Limits during SU/SD<br>average for each event<br><table><tr><td>Cold start</td><td>216 lb/turbine</td></tr><tr><td>Warm start</td><td>216 lb/turbine</td></tr><tr><td>Hot start</td><td>168 lb/turbine</td></tr><tr><td>shutdown</td><td>216 lb/turbine</td></tr></table><br>Tuning events are limited to no more than 18 consecutive hours.</td><td>Oxidation catalyst<br>GCPs</td><td>Stack test and CO CEMS correlation<br><br>Tracking duration of SU/SD and maintenance events.<br><br>Annual limit for tuning events</td></tr>
<tr><td>VOC</td><td>Auxiliary boilers and fuel gas heaters<br>0.005 lb/MMBtu</td><td>GCPs</td><td>Annual fuel throughput</td></tr>
<tr><td>VOC</td><td>Emergency generators<br>FWP-1 0.11 g/hp-hr<br>EG-1 1.0 g/hp-hr</td><td>GCPs</td><td>Annual hours of operation</td></tr>
<tr><td>$H_2SO_4$</td><td>Turbines<br>These limits apply at all times<br>0.0012 lb/MMBtu</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>$H_2SO_4$</td><td>Auxiliary boilers and fuel gas heaters</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>$H_2SO_4$</td><td>Emergency generators<br>0.000118 lb/MMBtu</td><td>ULSD fuel with 15 ppm S</td><td>Fuel monitoring</td></tr>
<tr><td>$SO_2$</td><td>Turbines<br>This limit applies at all times<br>0.00114 lb/MMBtu</td><td>Low sulfur fuel</td><td>Fuel monitoring, stack test</td></tr>
<tr><td>$SO_2$</td><td>Auxiliary boilers<br>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</td></tr>
<tr><td>$SO_2$</td><td>Emergency generators<br>0.00154 lb/MMBtu</td><td>ULSD fuel with 15 ppm S</td><td>Fuel certification and annual hours of operation</td></tr>
<tr><td>PM</td><td>Turbines<br>These limits apply at all times except during tuning<br>0.0052 lb/MMBtu</td><td>Low sulfur/ash fuel (pipeline quality NG with no more than 0.4 gr/100scf on an annual average) and GCPs</td><td>Stack test<br><br>Annual limit for tuning events</td></tr>
<tr><td>PM</td><td>Auxiliary boilers and fuel gas heaters<br>0.007 lbs/MMBtu<br>Auxiliary boilers<br>0.6 lbs/hr</td><td>Low sulfur/carbon fuel and GCPs</td><td>Annual fuel throughput</td></tr>
<tr><td>PM</td><td>Emergency generators<br>EG-1 0.15 g/hp-hr<br>FWP-1 0.15 g/hp-hr</td><td>Low sulfur fuel and GCPs</td><td>Annual hours of operation</td></tr>
<tr><td>$PM_{10}$</td><td>Turbines<br>These limits apply at all times except during tuning<br>12.3 lbs/hr (0.0052 lb/MMBtu) average of three test runs<br><br>Tuning events are limited to no more than 18 consecutive hours.</td><td>Low sulfur/ash fuel (pipeline quality NG with no more than 0.4 gr/100scf on an annual average) and GCPs<br><br>Minimizing duration of maintenance events.</td><td>Stack test<br><br>Annual limit for tuning events</td></tr>
<tr><td>$PM_{10}$</td><td>Auxiliary boilers and fuel gas heaters<br>0.007 lbs/MMBtu<br>Auxiliary boilers<br>0.6 lbs/hr</td><td>Low sulfur/carbon fuel and GCPs</td><td>Annual fuel throughput</td></tr>
</table>

| Pollutant | Equipment and Primary BACT | Control | Compliance |
|---|---|---|---|
| $PM_{10}$ | Emergency generators<br>EG-1 0.15 g/hp-hr<br>FWP-1 0.15 g/hp-hr | Low sulfur fuel and GCPs | Annual hours of operation |
| $PM_{2.5}$ | Turbines<br>These limits apply at all times except during tuning<br><br>12.3 lbs/hr (0.0052 lb/MMBtu) average of three test runs<br><br>Tuning events are limited to no more than 18 consecutive hours. | Low sulfur/ash fuel (pipeline quality NG with no more than 0.4 gr/100scf on an annual average) and GCPs<br><br>Minimizing duration of maintenance events. | Stack test<br><br>Annual limit for tuning events |
| $PM_{2.5}$ | Auxiliary boilers and fuel gas heaters<br>0.007 lbs/MMBtu<br>Auxiliary boilers<br>0.6 lbs/hr | Low sulfur/carbon fuel and GCPs | Annual fuel throughput |
| $PM_{2.5}$ | Emergency generators<br>EG-1 0.15 g/hp-hr<br>FWP-1 0.15 g/hp-hr | Low sulfur fuel and GCPs | Annual hours of operation |

The proposed control strategies are considered to be BACT for this source type and are no less stringent than NSPS standards.

IV. Initial Compliance Determination

A. Testing – stack testing is required for $NO_x$, CO, VOC, PM, $PM_{10}$, and $PM_{2.5}$ from the turbines and $NO_x$ and CO from the auxiliary boilers and fuel gas heaters 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 Chickahominy Power 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 boilers, and fuel gas heaters.

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.

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 Chickahominy Power 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 boilers, fuel gas heaters, 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 shall be performed (see Section V.C below).

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, 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 three combustion turbine generators (CT-1, CT-2, CT-3), 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 boilers (B-1, B-2) and the fuel gas heaters (FGH-1, FGH-2, FGH-3), 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 (CT-1, CT-2, CT-3), auxiliary boilers (B-1, B-2), and fuel gas heaters (FGH-1, FGH-2, FGH-3);

6. Monthly and annual net power output of the combustion turbine generators and associated steam turbines (CT-1, CT-2, CT-3);

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 Conditions 9, 10 and 23;

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. Results of daily AVO inspections for fugitive natural gas leak detection from the piping and components, including any repairs or other records required by Condition 19.

12. Scheduled and unscheduled maintenance, and operator training.

13. Results of all stack tests, power block heat rate tests, visible emission evaluations, and performance evaluations.

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

15. Records showing the circuit breakers are operating in accordance with the manufacturer's specifications (see Condition 20).

C. Further Testing

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

2. The permit requires subsequent testing every five years for $PM_{10}$, $PM_{2.5}$ and VOC.

3. Power block heat rate testing shall be done on the power blocks every 6 years to show compliance with Condition 8.

VI. Public Participation

The applicant held a public information session on May 17, 2017 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. The area surrounding the proposed Chickahominy Power Station includes federally recognized tribal lands. DEQ will separately notify the identified tribes of the opportunity to comment on the draft permit. Additionally, publication of the notice of public comment in a newspaper with local distribution will ensure that the local population will be able to access the notice. The notice of public comment appeared in the New Kent/Charles City Chronicle on January 31, 2019.

An information meeting and public hearing was held on March 5, 2019 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. Recommendations and limitations are provided in the draft permit letter.

Regional Engineer: Ali M. Gil

Date: May 28, 2019

Reviewing Engineer:_________________________ Date: May 28, 2019

Attachments:

- Appendix A – Calculation sheets
- Appendix B – Modeling Memo
- Appendix C – Environmental Justice reports