Engineering Analysis

Source Name: **Virginia Electric and Power Company – Greensville Plant** Permit No.: **52525-001**

Source Location: **2500 Rogers Rd. (Rt. 605), Greensville County, Virginia** Engineer: **AMS**

Date: **DRAFT**

I. Introduction and Background

A. Company Background

The facility, as proposed, will be a new, combined-cycle, natural gas-fired, electrical power generating facility. The facility will be located on a 1,143-acre parcel just west of the intersection of State Route 620 (Radium Rd.) and State Route 605 (Rogers Rd.) on the Brunswick County/Greensville County Line. The nearest residences are approximately a half a mile to the east and to the northwest. The nearest schools are located around Emporia approximately 5.0 to 6.5 miles away to the east. The nearest hospital/medical center is also in Emporia, over 5 miles away, as are the nearest senior care facilities. There are no Class I areas within 100 km of the proposed facility (see PSD section). This facility will be about 4.5 miles to the east/southeast of the newly constructed Brunswick County Power Station (Registration # 52404) and is proposed to include a switching station.

The area is in attainment for all pollutants. Since the source will be a major source, with emissions over 100 tons/yr of nitrogen oxides (NO_x or NO_2), carbon monoxide (CO), volatile organic compounds (VOC), particulate matter less than 10 microns (PM_{10}), particulate matter less than 2.5 microns ($PM_{2.5}$), and greenhouse gas [GHG or CO_2 equivalents (CO_2e)] over 75,000 tons/yr, Prevention of Significant Deterioration (PSD) permitting for those pollutants - as well as sulfur dioxide (SO_2) and sulfuric acid mist (H_2SO_4) emissions - will be triggered. The source will not be major for hazardous air pollutants (HAP), so no MACT will apply, and the source will be subject to the State Toxics Rule (6-5).

Site Suitability:

The facility will be located on a site which is suitable from an air pollution standpoint. The area is rural with a combination of undeveloped and transitional land (tree plantations and farms). An existing electric transmission line is less than 1,000 feet to the west. The site is an upland area (elevation 150-200 ft). The Meherrin River borders the southern end of the property site and Greensville Creek will transect it. Additionally, the County of Greensville 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 Local Governing Body Certification Form in the application).

The following table shows the distances between the proposed plant site and the closest Class I areas. The Federal Land Managers were given the opportunity to comment on whether they will provide a finding of adverse impact on visibility in these Class I areas as a result of the proposed facility. The project does not result in an adverse impact on visibility.

Class I area	Distance from project
Shenandoah National Park	180 km
James River Face Wilderness Area	180 km
Dolly Sods Wilderness Area	289 km
Swanquarter National Wildlife Refuge	185 km

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) 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 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. In accordance with PSD regulations, air quality modeling was conducted to predict the maximum ambient impacts of criteria pollutants emitted by the proposed source. Class I air quality analyses are typically performed for PSD facilities within 100 kilometers of a Class I area (an area such as a national park or wildlife sanctuary). In addition, Class I modeling is also done for large sources having the capability to affect air quality at distances up to 300 kilometers. An analysis was done to determine compliance with Class I PSD increment for SO_2, PM_{10}, $PM_{2.5}$, and NO_2. The maximum predicted concentrations of those pollutants were well below the Class I significant impact levels (SILs) so no additional air quality analysis was required for Class I area impact.

   The Class II (all other areas not designated as Class I areas) modeling analysis, predicted that impacts from CO (1-hour averaging periods), PM_{10} (24-hour and annual averaging periods), and SO_2 (1-hour, 3-hour, 24-hour, and annual) were below applicable modeling significant impact levels (SILs). No further analyses were required for these pollutants at the indicated averaging periods. However, modeled concentrations for NO_2 (1-hour and annual averaging periods) and CO (8-hour averaging period) exceeded the applicable SILs and a full impact analysis was done. Also a full impact analysis was done for $PM_{2.5}$ (24-hour and annual averaging periods) because VADEQ does not currently have state-specific SILs for the purpose of excluding a project from performing a full impact analysis. Therefore, a cumulative impact analysis for these pollutants and averaging periods was necessary. The predicted impacts for NO_2, CO, and $PM_{2.5}$ from the cumulative impact analysis were less than the applicable National Ambient Air Quality Standards (NAAQS) and Class II area PSD increments. Hence, the proposed project does not cause or significantly contribute to a predicted violation of any applicable NAAQS or Class II area PSD increment.

   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 such as those proposed by Dominion are subject to the standards in 9 VAC 5-60-300 et seq. Dominion calculated the emissions of toxic pollutants from all of the emission units proposed for the site. Dominion modeled emissions of toxic pollutants for which proposed emissions exceeded the thresholds in 9 VAC 5-60-320 (acrolein, beryllium, cadmium, chromium, formaldehyde, lead, mercury, and nickel). Modeling demonstrated that proposed emissions of these toxics pollutants are well below the associated Significant Ambient Air Concentrations (SAACs).

   A visibility analysis was done to assess the potential for visual plume impacts in Class II areas within 50 km of the projected site and it was determined that the plume would not be visible within any PSD Class II potentially sensitive area (Lake Gaston). The facility is required to use clean-burning fuels and air pollution control equipment, and is limited to opacity not to exceed 10% at the turbine stacks.

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

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. The signed Local Governing Body Certification Form is included in the application.

   The proposed Greensville County Power Station will generate electricity using only clean-burning natural gas. The availability of clean fuel electric generation facilities is necessary if operation of conventional coal-fired power plants is to be reduced or replaced. Construction of clean-burning, efficient generation plants, such as the proposed facility, creates the potential for regional SO_2 and NO_x reductions resulting from displacement of older, more-polluting forms of electricity generation.

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

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

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

   a. 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 toxics emissions and has been modeled and shows compliance with the applicable SAACs. The emissions for criteria pollutants associated with this permit have likewise been modeled and have been shown through modeling to not cause or contribute to a violation of the ambient air quality standards or allowable increments within any Class I or Class II areas.

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

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

   The permit requires numerous pollution control strategies that will result in reduction of emissions from the combustion turbines and associated equipment. These include technologies such as the use of clean fuels with low sulfur content, good combustion practices, and clean-burning "low-NO_x" lean premix burners as well as add-on control (SCR for NO_x removal and an Oxidation Catalyst for CO, VOC, and VOC toxic pollutant control). Other measures have been included in the draft permit, such as a requirement to use ultra-low sulfur diesel oil (no more than 0.0015 % by weight) or propane 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" Best Available Control Technology (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, nominal 1,600 MW combined-cycle electrical power generating facility utilizing three combustion turbines each with a duct-fired heat recovery steam generator (HRSG) with a common reheat condensing steam turbine generator (3 on 1 configuration). The proposed fuel for the turbines and duct burners is pipeline-quality natural gas. Emissions from the turbines will be controlled by the use of low carbon fuels and high efficiency design (for GHG), clean fuels and good combustion practices (for PM_{10} and $PM_{2.5}$), SCR and low NO_x burners (for NO_x), and oxidation catalyst (for CO and VOC). A natural gas-fired auxiliary boiler, six fuel gas heaters, an auxiliary equipment cooler, four inlet chillers, an emergency diesel fire water pump, three emergency generators, and an oil storage tank are also proposed and will be subject to emission controls. Natural gas piping components and electrical circuit breakers potentially emit GHG pollutants (expressed as carbon dioxide equivalents, or CO_2e) and they will also be covered in the permit.

Table 1 - Expected emissions from the proposed facility are as follows:

Pollutant	Emissions (tons/yr)
NO_x	370.8
CO	929.8
SO_2	56.5
VOC	646.9
PM_{10}	188.6
$PM_{2.5}$	188.1
CO_2e	5,783,753.0
Sulfuric acid mist (H_2SO_4)	29.8
Acrolein	0.18
Formaldehyde	6.43
Beryllium	0.00058
Cadmium	0.053
Chromium	0.068
Lead	0.024
Mercury	0.013
Nickel	0.10

Note: Emissions of regulated toxic pollutants other than those listed above are below permitting exemption thresholds and were therefore not included in Table 1.

C. Process and Equipment Description

Equipment to be Constructed			
Ref. No.	**Equipment Description**	**Rated Capacity**	**Federal Requirements**
Three on one power block with three natural gas-fired combustion turbine generators, each with a duct-fired heat recovery steam generator (HRSG) , providing steam to a common steam turbine generator			
CT-1	MHPS M501J combustion turbine generator with duct burner (natural gas-fired)	3,227 MMBtu/hr CT 500 MMBtu/hr DB	NSPS Subpart KKKK

Equipment to be Constructed			
Ref. No.	**Equipment Description**	**Rated Capacity**	**Federal Requirements**
CT-2	MHPS M501J combustion turbine generator with duct burner (natural gas-fired)	3,227 MMBtu/hr CT 500 MMBtu/hr DB	NSPS Subpart KKKK
CT-3	MHPS M501J combustion turbine generator with duct burner (natural gas-fired)	3,227 MMBtu/hr CT 500 MMBtu/hr DB	NSPS Subpart KKKK
Ancillary Equipment			
B-1	Auxiliary Boiler (natural gas-fired)	185 MMBtu/hr	NSPS Subpart Db
FGH-1,2,3	Three Fuel Gas Heaters (natural gas-fired)	16.1 MMBtu/hr each	NSPS Subpart Dc
FGH-4,5,6	Three Fuel Gas Heaters (natural gas-fired)	7.8 MMBtu/hr each	None
EG-1	Emergency Generator (S15 ULSD)	3000 kW	NSPS IIII, MACT ZZZZ
EG-2 & 3	Two Emergency Generators (propane)	150 kW (230 hp) each	NSPS JJJJ, MACT ZZZZ
FWP-1	Fire Water Pump (S15 ULSD)	376 bhp	NSPS IIII, MACT ZZZZ
DC-1	Delugeable Auxiliary Equipment Cooler	180,000 gallons of water/hr	None
IC-1 through 4	Four Turbine Inlet Air Chillers (mechanical draft cooling towers)	581,400 gallons of water/hr each	None
CB-1 through CB-11	Eleven Electrical Circuit Breakers	1,645 lbs SF_6 per breaker	None
CB-12 through CB-14	Three Generator Breakers	110 lbs SF_6 per breaker	None
FUG-1	Fugitive equipment leaks from natural gas piping components	-	None
T-1	ULSD storage tank	6,000 gallons	None

1. Combustion Turbine Generators with duct-fired Heat Recovery Steam Generators (CT-1, CT-2 and CT-3)

   a. Combustion Turbines (CT)

      The source has proposed the installation of three MHPS M501J class CTs in combined-cycle mode.

      The gas turbine is the main component of a combined-cycle power system. First, air is filtered, cooled and compressed in a multiple stage axial flow compressor. Compressed air and fuel are mixed and combusted in the turbine combustion chamber. Lean pre-mix dry low-NO_x combustors minimize NO_x formation during natural gas combustion. Hot exhaust gases from the combustion chamber are expanded through a multi-stage power turbine that results in energy to drive both the air compressor and electric power generator.

      The CTs are designed to operate in the dry low-NO_x mode at loads from approximately 50 percent up to 100 percent rating. Operation at lower loads will only occur during startup and shutdown. The CTs will be periodically taken out of service for scheduled maintenance, or as dictated by economic or electrical demand conditions.

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

      i. Turbine tuning – Turbine tuning consists of adjusting the air-to-fuel ratio under a wide range of load and atmospheric conditions in order to optimize turbine performance, while minimizing emissions. On a periodic and as-needed basis, planned maintenance of the turbine blades 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 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 averaging time of a 24-hour calendar day to meet the short term NOx and CO limits (units would be lb/turbine/day which is derived from the normal short term limit extended over the 24-hour calendar day). Approximately 96 hours per year per turbine is expected to be utilized for this maintenance.

ii. Water washing of turbine blades – When the turbine blades become dirty over time, the efficiency of the turbine declines, so it is necessary to wash the blades on a periodic basis. Water washing involves spraying water into the turbine while it is operating and is expected to take no more than 60 minutes per event per turbine. This process could temporarily disrupt the combustion characteristics of the turbine and affect the inlet concentrations of NOx and CO to a point where it would not be expected to meet the normal lb/hr or other short-term emission limits over a three hour averaging period (or one-hour average for NO_x) but could meet the lb/hr emission limit over a longer averaging time. The permittee requests an alternate averaging time of a 24-hour calendar day to meet the short term NOx and CO limits (units would be lb/turbine/day which is derived from the normal short term limit extended over the 24-hour calendar day). Approximately 52 water wash events are predicted per year to accomplish this maintenance.

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

The proposed facility will use three HRSGs, one for each CT, which will use waste heat to produce additional electricity. 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 (ST). Exhaust gas entering the HRSG at approximately 1,200°F will be cooled to 170°-190°F by the time it leaves the HRSG exhaust stack. Steam production in the HRSGs will be augmented using duct burners (DBs) that will be fired by natural gas. The proposed DBs will have a firing rate of 500 MMBtu/hr each. The heat recovered is used in the combined-cycle plant for additional steam generation and natural gas/feedwater heating. Each HRSG will include high-pressure superheaters, a high-pressure evaporator, high-pressure economizers, reheat sections (to reheat partially expanded steam), an intermediate-pressure superheater, an intermediate-pressure evaporator, an intermediate-pressure economizer, a low-pressure superheater, a low-pressure evaporator, and a low-pressure economizer. The dry condenser will condense the steam exhausting from the ST. As the steam is condensed, the condensate flows to the condensate receiver tank. Control devices such as selective catalytic reduction (SCR) will be installed, to control NO_x emissions, and oxidation catalysts will be installed to control CO and VOC emissions.

c. Steam Turbine (ST)

The proposed project includes one reheat, condensing steam turbine generator designed for variable pressure operation. The high-pressure portion of the steam turbine generator 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 steam turbine generator also receives excess low-pressure superheated steam from the HRSGs and exhausts to the air-cooled condenser. The steam turbine generator set is designed to produce up to approximately 600 MW of electrical output at ISO conditions with duct firing. No pollutants are emitted from the steam turbine.

2. Ancillary Equipment

   a. Turbine Inlet Air Chillers (IC-1 through IC-4)

      Four mechanical draft cooling towers will be incorporated to provide air inlet chilling for the CTs. These devices will cool the inlet area during periods of high ambient temperature in order to increase power output and improve efficiency. Particulate matter emissions from the cooling towers associated with the inlet air chillers will be controlled by high efficiency drift eliminators.

   b. Auxiliary Boiler (B-1)

      The proposed facility will include a 185.0 MMBtu/hr, natural gas-fired, auxiliary boiler. The auxiliary boiler will provide steam to the ST at startup and at cold starts to warm up the ST rotor. The steam from the auxiliary boiler will not be used to augment the power generation of the CTs or ST. The boiler is proposed to operate 8760 hrs/yr but will be limited by an annual fuel throughput based on a capacity factor of 10%. NO_x emissions from the boiler will be controlled by the use of low NO_x burners.

   c. Fuel Gas Heaters (FGH-1 through FGH-6)

      The proposed facility will include three 7.8 MMBtu/hr (FGH-4 through 6) and three 16.1 MMBtu/hr (FGH-1 through 3), 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 8760 hrs/yr. NO_x emissions from the heaters will be controlled by the use of low NO_x burners.

   d. 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 (including 100 hrs of maintenance checks and readiness testing). The emergency generator will provide power in emergency situations for turning gears, lube oil pumps, auxiliary cooling water pumps and water supply pumps. The emergency diesel generator is not intended to provide sufficient power for a black start, peak shaving or non-emergency power.

   e. Propane-Fired Emergency Generators (EG-2 and EG-3)

      The proposed facility will include two 150 kW propane-fired emergency generators that will be operated up to 500 hours per year each (including 100 hrs of maintenance checks and readiness testing). The emergency generators will provide power in emergency situations for the uninterruptible power supply for the control house in the switchyard. The emergency propane generators are not intended to provide sufficient power for a black start, peak shaving or non-emergency power.

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

      The proposed project will include a 376 bhp diesel-fired fire water pump operated as a fire water pump driver. The unit will be limited to 500 hours per year, including monthly testing and maintenance (not to exceed 100 hours per year).

   g. Distillate Oil Storage Tank (ST-1)

      The proposed project will include a 6,000-gallon, fixed-roof, horizontal, distillate oil storage tank to provide fuel for the emergency generator and fire water pump.

h. Circuit Breakers (CB-1 through CB-14)

The proposed project will include 14 circuit breakers holding a total of 18,425 lbs of the greenhouse gas sulfur hexafluoride (SF_6) per unit. There will be 11 circuit breakers holding 1,645 lbs of SF_6 each and three smaller units holding 110 lbs of SF_6 each. Maximum annual leakage rate for SF_6 is to be no more than 0.5%.

i. 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. The components will be monitored daily and leaks will be repaired promptly.

j. Delugeable Auxiliary Equipment Cooler (DC-1)

Dominion proposes to construct a 16-bay delugeable auxiliary equipment cooler which will cool the lubricating oil for miscellaneous equipment. Forced-draft fans will be incorporated to provide the flow needed for the equipment cooler. The cooler will have six bays equipped with deluge water sprays for additional cooling during extremely hot weather, causing particulate matter emissions from drift.

D. Project Schedule

Date permit application received in region	November 24, 2014 (amended August 26, 2015 for gas-only operation, and December 9, 2015 for inclusion of modeling information, and February 10, 2016 for su/sd and alternative operating scenarios)
Date application was deemed complete	February 10, 2016
Proposed construction commencement date	July 2016
Proposed startup date	January 2018

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

Proposed emissions are primarily products of combustion from the combined cycle units and duct burners. There are also emissions from the auxiliary boiler, fuel gas heaters, emergency generators, emergency firewater pump, turbine inlet chillers, auxiliary equipment cooler, and circuit breakers. Permitted emission limits reflect BACT (see section III.G for BACT analysis).

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

The permit will include periodic testing for PM_{10}, $PM_{2.5}$, and VOC every 5 years. The permittee will conduct an initial stack test for those pollutants and, based on the results, will develop approved emission factors and, with fuel throughput monitoring, will perform monthly calculations to determine a 12-month rolling total to show compliance with annual emission limits for these pollutants from the combustion turbines and associated duct burners. Particulate emissions from natural gas are mainly due to incomplete combustion of the low-ash gaseous fuel and are PM_{10} or smaller. Incomplete combustion also results in higher VOC and CO emissions. Compliance with the CO emission limit is an indication of compliance with the VOC and all of the particulate emission limits. The indication provided by compliance with the CO emission limit in conjunction with the additional testing that has been added every five years ensures the relationship between CO, VOC, and particulate remains accurate over the life of the units and provides a reasonable assurance of compliance.

The turbines will also have a lb CO_2/MWh limit and a Btu/kWh heat rate limit to show compliance with the energy-efficiency requirements for GHG BACT and NSPS Subpart TTTT. CO_2 will be monitored using CEMS. N_2O and CH_4 emissions will be calculated using 40 CFR Part 98 factors. Total CO_2, N_2O and CH_4, along with their associated Global Warming Potential factors, will determine CO_2e emissions.

Emissions from startup and shutdown were included in the annual permit emissions limits for the combustion turbines, but separate annual limits will not be included. During startup and shutdown, some post-combustion controls are not working at the optimum level of control, however, during these periods, the turbines and duct burners are also not operating at their highest output and other emissions may be reduced for that reason. Therefore it is important to consider emissions during startup and shutdown in the annual total for emissions. Worst case annual emissions were based on either 8,760 hrs/yr with duct burning, or 5,476 hrs/yr with duct burning plus startup and shutdown (SU/SD) emissions (estimated at approximately 369 hours/year with 2,920 hours of downtime). The facility was not given a limit on the total number of hours of startup and shutdown, but rather the estimated amount of time was factored into the annual emission limits and, therefore, must be complied with by showing compliance with the annual emission limits. BACT applies during startup and shutdown and BACT includes minimization of such SU/SD events (See Section III.G for more information).

Emissions from the fuel gas heaters, auxiliary equipment cooler, and inlet chillers were based on 8,760 hrs/yr operation. The emergency generators and fire water pump are permitted to operate no more than 500 hrs/yr. Emissions from the auxiliary boiler were based on fuel consumption while limited to an annual capacity factor of 10% of available operating time.

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

Emissions from the circuit breakers were based on a maximum annual leakage rate of 0.5%.

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 best available control technology (BACT) for GHG. The total CO_2e is based on taking the mass emissions of each GHG and multiplying by its Global Warming Potential (GWP). These GWP factors are as follows: CO_2: 1; CH_4: 25; N_2O: 298; SF_6: 23,800. The first three GHG pollutants are primarily from fuel burning and the SF_6 is from semi-conductors. This facility has electrical circuit breakers which contain SF_6.

   Since the Greensville 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.

   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.6 below for more details.

B. PSD Permitting: The source is PSD-major for PM_{10}, $PM_{2.5}$, NO_x, CO, and VOC (see Table 2 below). Because one or more pollutants are subject to PSD, the 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 exceed the 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.

   Table 2- PSD Permitting applicability

Pollutant	Potential to Emit (TPY)	PSD Major Threshold (TPY)*	Over Major Threshold?	PSD Significance Rate (TPY)**	PSD Required?
PM_{10}	188.6	100	**Yes**	15	**Yes**
$PM_{2.5}$	188.1	100	**Yes**	10	**Yes**
NO_x	370.8	100	**Yes**	40	**Yes**
CO	929.8	100	**Yes**	100	**Yes**
SO_2	56.5	100	No	40	**Yes**
VOC	646.9	100	**Yes**	40	**Yes**
CO_2e	5,783,753.0		**Yes**	75,000	**Yes**
Lead	0.02	100	No	0.6	No
H_2SO_4	29.8	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 are subject to NSPS Subpart KKKK (Standards of Performance for Stationary Combustion Turbines) which requires the source to meet NO_x and SO_2 standards. The source must meet a NO_x limit of 15 ppm @ 15% O_2 or 0.43 lb/MWh when burning natural gas. The source proposes the use of low NO_x burners and SCR to control NO_x emissions. NO_x emissions from the proposed combustion turbines are expected to be around 2.0 ppmvd when burning natural gas which is below the NSPS standard and is considered Best Available Control Technology (BACT). The source will put NO_x CEMS on the turbine stacks to show compliance with the BACT limits.

   The source proposes using low-sulfur fuel (natural gas) to control SO_2 and H_2SO_4 from the turbines and duct burners. To be in compliance with NSPS KKKK, they must not exceed 0.06 lb SO_2/MMBtu or 0.9 lb/MWh gross output from fuel burning. The source has proposed a BACT emission limit of 0.00112 lb SO_2/MMBtu. BACT is discussed in more detail in Section III.G. Turbines regulated under NSPS Subpart KKKK are not subject to NSPS Subpart GG, and HRSGs and duct burners regulated under NSPS Subpart KKKK are not subject to NSPS Subparts Da, Db, or Dc.

2. Subpart Db: The 185.0 MMBtu/hr auxiliary boiler is subject to NSPS Subpart Db Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units as a steam-generating unit greater than 100 MMBtu/hr. Since the unit will be limited to a 10% capacity factor, under 40 CFR 60.44b(j) and (k), the unit is not subject to a Db NO_x standard. As a natural gas-fired unit, it is not subject to the SO_2 standard [40 CFR 60.42b(k)(2)]. Fuel receipts that certify the fuel meets the definition of natural gas must be kept at the facility [40 CFR 60.49b(r)] for a period of two years. Opacity monitors (COMS) are not required [40 CFR 60.48b(j)].

3. Subpart Dc: The three 16.1 MMBtu/hr fuel gas heaters are subject to NSPS Subpart Dc, Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units as a steam-generating unit between 10 and 100 MMBtu/hr. Records of the amount of fuel burned in each unit each calendar month must be kept [40 CFR 60.48c(g)(2)].

4. Subpart IIII*: The emergency diesel fire water pump and diesel emergency generator are subject to NSPS Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines. The 376 bhp diesel fire water pump is subject to a NO_x + non-methane hydrocarbon (NMHC) limit of 4.0 g/kW-hr, a PM limit of 0.2 g/kW-hr, a CO limit of 3.5 g/kW-hr (Table 4 of NSPS Subpart IIII), and a requirement to use ULSD with no more than 15 ppm sulfur content. The 3000 kW diesel emergency generator is subject to a NO_x + NMHC limit of 6.4 g/kW-hr, a PM limit of 0.2 g/kW-hr, a CO limit of 3.5 g/kW-hr (Table 1 of 40 CFR 89.112), and a requirement to use ULSD with no more than 15 ppm sulfur content (S15 ULSD).

5. Subpart JJJJ*: The two 150 kW emergency propane-fired generators are subject to NSPS Subpart JJJJ Standards of Performance for Stationary Spark Ignition Internal Combustion

Engines, with a requirement to use certified engines and maintain them properly.

*(regarding items III.C.4 and III.C.5 above) Although the source must be in compliance with the requirements for these emergency units, DEQ has not requested delegation for enforcement of these regulations. BACT limits are not less stringent than the NSPS standards.

6. Subpart TTTT Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units: As of May 2016, DEQ has not requested delegation to enforce this regulation, but the facility will need to demonstrate compliance with the standards in this subpart. This regulation applies to stationary combustion turbines that commence construction after January 8, 2014. The standard for a natural gas-fired combustion turbine is a CO_2 emission limit of 1,000 lb/MWh of gross energy output. NSPS Subpart TTTT requires EGUs subject to the gross energy output standard to measure (Appendix D, Part 75) or calculate (Appendix G, Part 75) CO_2 mass emissions and record the hourly gross electrical output from the EGU using watt meters. EGUs that are subject to NSPS Subpart TTTT are excluded from being affected EGUs under NSPS Subpart UUUU. Virginia anticipates asking EPA to incorporate the NSPS TTTT into the Virginia SIP in the near future. Until that time is not delegated to enforce this regulation.

D. MACT Requirements:

1. Subpart ZZZZ*: The emergency diesel fire water pump and emergency generators are also subject to MACT Subpart ZZZZ National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (40 CFR 63.6590.c.1) for area sources of HAP. Compliance with this MACT is met by complying with NSPS Subpart IIII or NSPS Subpart JJJJ requirements, as applicable.

   *DEQ has not accepted delegation to enforce this federal regulation for area HAP sources, however this facility is a major source for pollutants other than HAP and will be subject to Title V permitting with applicable requirements contained therein.

2. Non-applicable Subparts: As an area HAP source, the facility will not be subject to MACT Subpart YYYY for turbines or MACT Subpart Q for cooling towers.

E. Other:

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

2. Title IV/Acid Rain Permit: The source will also be subject to the Acid Rain permit regulations. The source will be subject to Article 3 Federal Operating (Title IV) permitting and must submit an application no later than 24 months before the date the unit commences operation.

F. State New Source Review: Emissions subject to Major New Source Review (Article 8 – PSD) are not subject to Article 6 New Source Review as per 9 VAC 5-80-1100H. The only criteria pollutant that is not subject to PSD is lead. The total lead emissions from the facility are 0.02 tons/yr. This is below the exemption rate for lead in 9 VAC-5-80-1105C, however, 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).

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 attachment).

2. Toxic Pollutants

MACTs have been promulgated for Combustion Turbines that are major sources of HAP (Subpart YYYY National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines) and for cooling towers at major sources of HAP (Subpart Q National Emission Standards for Hazardous Air Pollutants for Industrial Process Cooling Towers). HAP emissions from this facility will be below major levels, so there will be no MACT requirements for the Combustion Turbines or Cooling Towers.

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

Since these units are not subject to promulgated MACTs, the State Toxics Rule applies. HAPs that exceed the exemption rate in 9 VAC 5-60-300 are acrolein, formaldehyde, beryllium, cadmium, chromium, lead, mercury, and nickel. Emission limits for these HAPs will appear in a State Only section of the permit. Modeling has shown that emissions of these HAPs will not exceed the Standard Ambient Air Concentration (SAAC) (see modeling memo attachment). Testing for formaldehyde will be incorporated into the permit to show compliance with the vendor-supplied emission factor on which the hourly and annual emissions were based.

The emergency diesel fire water pump and emergency generators are subject to MACT Subpart ZZZZ as an area source as per the application submitted by Dominion. The requirements for these units will be to comply with NSPS Subpart IIII or NSPS Subpart JJJJ requirements, which will be enforced by EPA, not DEQ.

G. Control Technology

PSD BACT: Sources that are subject to PSD permitting, must apply BACT to those pollutants that triggered PSD permitting (see Table 2 in Section III.B). The determination of BACT usually involves a top-down method:

Step 1 – Identify all possible 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 the BACT cost feasibility analysis be based upon recent permit determinations for similar facilities. 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, expressed in dollars per ton, is to be compared with the cost incurred by other sources of the same industry type. A listing of BACT determinations from the RACT/BACT/LAER Clearinghouse (RBLC) for similar facilities is included as Appendix C in the Dominion – Greensville application. The scope of the application is a natural gas-fired, combined cycle turbine with duct fired HRSGs.

1. Greenhouse gases: In this case, CO_2e emissions from the proposed facility trigger PSD permitting (on both a mass basis and CO_2e basis, see Table 2 above) so BACT must be determined for CO_2e. CO_2e is a relatively new regulated pollutant so there are fewer determinations in the RACT/BACT/LAER Clearinghouse to compare.

a. Combustion Turbines

i. Possible Control Technologies (Step 1):

- Carbon capture and sequestration/storage: One such technology that is being discussed to control CO_2 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, 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 fuel combusted to produce the desired amount of electricity). This has been the most accepted BACT 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 and CO_2 emissions can be minimized.

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

- Using renewable energy or alternative energy sources - such as solar thermal electric, photovoltaics, landfill gas, wind, biomass, hydroelectric, nuclear, geothermal electric, energy from waste, anaerobic digestion, tidal energy, and wave energy - reduces the use of fossil fuels.

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 proven option for a natural gas, combined cycle combustion turbine whose exhaust is characterized by high flow and low CO_2 concentration. Of the 22 CCS projects around the world, only three are power plants (all coal) and only one of them is currently operating in Canada (www.carbonbrief.org dated Oct. 7, 2014). CO_2 transport poses a problem as well. The proposed location does not appear to be geologically ideal for CCS but could offer some marginal options. Areas in southwest Virginia are more promising for this aspect of CCS but a pipeline does not currently exist. CO_2 storage in geologic formation 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 (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 larger units, especially coal burning units, which have the potential to emit CO_2 in larger concentrations than this plant, and that are located near sequestration areas. The feasibility and availability of CCS for the proposed power facility is marginal, at best.

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

Low carbon fuels are technically feasible and available for this project

The Department has reviewed the available information and the case-specific facts for the Greensville facility. After that review, the Department has determined that requiring solar generation, either in its entirety or as a supplemental fuel source, constitutes redefinition of the Greensville facility. The commenter appears to indicate that requiring significantly different equipment to be designed and installed in addition to the proposed equipment is simply supplementing fuel. The Greensville facility must be able to respond to changing demands for electricity at the time it occurs. As noted in the comment, solar production is only “likely to coincide with optimal solar generation conditions." Supplementation of power production to meet high energy demands must be available at the time needed and does not serve its purpose if its availability is limited. Solar generation requires different engineering and equipment than a combustion turbine. The Department considers solar generation to be a redesign of the source for the Greensville facility. Greensville County is not an ideal location for wind power generation, nor is it practical for hydro power, tidal power, or wave power. Geothermal electric production is not viable in Virginia. And, although renewable energy (i.e., biomass) reduces 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. (http://www.energy.vt.edu/vept/index.asp). 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.

Therefore, DEQ finds that that the use of these alternative fuels would be considered redefining the source.

iii. Rank GHG control technologies (Step 3):

Since BACT is based on an emission limitation which reflects the maximum degree of reduction for a particular pollutant, then the best means of comparison is of emission limits rather than % control efficiency. Since energy efficiency plays a role in GHG emissions, one must compare efficiency limits based on output (Btu/kWh or lb/kWh) rather than mass limits based on heat input (lb/MMBtu). 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 increasing emissions. The number of CCTs applying GHG BACT has increased markedly in the past few years. As can be seen in Table 3 below, this project is a bit larger than most of the other, recently permitted or proposed NGCC projects. Keeping in mind that thermal efficiency increases with larger turbines, and the net heat rate (Btu/kWh) decreases, the BACT level proposed for the 1,600 MW Greensville plant and the other permitted or proposed 180-1,400 MW plants is comparable. When comparing a heat rate limit, it is important to know whether it is based on a HHV or LHV and whether it is for a gross power output or a net power output, and duct fired or not duct-fired operation. This is not always evident when researching other facilities in the RBLC. Also, some GHG BACT proposals include a "degradation factor" which takes into consideration the heat rate of a unit as it gets older and less-efficient (see discussion of the proposed BACT in Section 5 of Dominion's application for a detailed list of energy efficient practices that are proposed). More recently permitted plants have considered degradation, while earlier permitted plants may not have.

Table 3 – Comparison of GHG BACT determinations

Year	**Facility**	**Type**	**GHG BACT limits**	**Basis**
2015	Moundsville Power LLC WV	589 MW NGCC	793 lb/MWh (gross, does not apply at all times)	Low carbon fuel
2014 draft	Austin Energy, Sand Hill Energy Ctr, TX	222 MW NGCC	7943 Btu/kWh HHV gross 930 lb/MWh	Energy efficiency processes, practices, and design
2014	Pinecrest Energy Ctr, TX	735 MW NGCC	942 lb/MWh	Energy efficiency, good design and combustion practices
2014	FGE Power LLC, TX	1620 MW NGCC	7,625 Btu/kWh net output 889 lb/MWh w/or w/o duct burning (gross, no SSM)	Energy efficiency processes, practices, and design
2013	LaPaloma Energy Ctr, TX	735 MW	7679 Btu/kWh 942 lb/MWh	Energy efficiency, good design and combustion practices
2013	Dominion VA- Brunswick, VA	1400 MW NGCC	7500 Btu/kWh (net HHV) 920 lb/MWh	Thermal Efficiency

Year	Facility	Type	GHG BACT limits	Basis
2012	Pioneer Valley Energy, MA	431 MW CC (oil backup)	6840 Btu/kWh 895 lb/MWh (gross)	Thermal Efficiency
2012	Calpine DPEC, TX	1300 MW 180 MW NGCC	7730 Btu/kWh (net) 920 lb/MWh	Thermal Efficiency
2012	Calpine CEC, TX	180 MW NGCC	7730 Btu/kWh (net) 920 lb/MWh	Thermal Efficiency
2011 draft	Cricket Valley Energy Ctr, NY	1000 MW NGCC	7605 Btu/kWh (net HHV) 950 lb/MWh	Thermal Efficiency
2011	LCRA Ferguson replacement, TX	590 MW NGCC	7720 Btu/kWh (net HHV) 918 lb/MWh	Thermal Efficiency
2011	PacifiCorp Lake Side, UT	629 MW NGCC	6918 Btu/kW (HHV) 950 lb/MWh (gross)	Thermal Efficiency
2010	Calpine RCEC, CA	600 MW NGCC	7730 Btu/kWh	Thermal Efficiency

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.

iv. BACT determination for GHG- most effective controls (Step 4):

Of the technologies mentioned in Step 1 above, construction of a carbon capture control, transport and storage system for CO_2 gas in the Greensville County region would be cost-prohibitive. A recent study suggested that adding CCS technology could increase plant construction costs up to $200 million[2]. Dominion calculated that construction of a pipeline to transport the collected CO_2 would be $260 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 (see Section 5 of Dominion's application for a more in-depth analysis).

The remaining technologies, namely efficient power generation and the use of low carbon fuels, are proposed for this facility and are accepted as BACT.

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

Dominion originally proposed operating at a higher heating value heat rate of no more than 7,356 Btu/kWh (based on a degradation estimate* for a new 6,564 Btu/kWh unit – HHV/net), and emit CO_2e at an average annual rate not to exceed 903 lb CO_2e/MWh (which reflects a 119.12 lb CO_2/MMBtu average monitored emission rate at similar facilities adjusted by a 3% margin to account for emissions from SU/SD and low load operation)

*The degradation estimate was based on a 3.4% performance margin of the combustion turbines, a 1.2% degradation margin for the auxiliary power, and a 7.1% degradation margin for the steam turbine system – 6564 x 1.034 x 1.012 x 1.071 = 7356 Btu/kWh net HHV. And 119.12 lb/MMBtu x 7356 Btu/kWh x 1.03 x 1,000 kWh/MW x 1 MMBtu/1,000,000 Btu = 903 lb/MWh gross.

Upon request from DEQ, Dominion submitted additional information consisting of 51 different operating scenarios (cases). These cases addressed operation at various ambient conditions and operating loads. These cases were submitted in support of a

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)

possible equation-based limitation, whereby turbine operation and ambient conditions would be continuously monitored and an annual limit continuously calculated based on those data. This approach is a significant deviation from the draft permit and presented an overly complex approach. The resulting limit would have lacked clarity and presented little to no environmental benefit. The Department did not pursue this option.

However, Dominion's data indicated that the original value was based on annual operation at a short-term worst-case 98^{o}F (Case 5). While permit limits may be properly based on worst-case operations, the GHG limit is annual (12-month rolling); some consideration must be given to expected operation over the entire period. As the proposed case is based on the short-term worst-case, the other submitted data was reviewed to determine the appropriate GHG limit.

After excluding Case 5, the Department reviewed Dominion's submitted Case 6, maximum operations of 3 turbines at ISO conditions without duct burners, which is the most efficient mode of operation for the Greensville facility. Case 6 indicates a design heat rate of 6,150 Btu/kWh net and an emission rate of 722 lb CO_2e/MWh gross. Taking Case 6 values as a starting point, adjustments were made as follows: gross to net (2%), startup/shutdown operations (3%), degradation over 36 years (11.7%), and compliance margin (5%). The resulting values are 7,213 Btu/kWh and 890 lb CO_2e/MWh. Both values are based on HHV and net power.

A BACT determination must be achievable at all times and properly considers all proposed modes of operation. Therefore, the starting point of utilizing Case 6 must be reviewed to determine if that approach results in an achievable BACT limit. To that end, the Department reviewed all the available information submitted by Dominion and commenters. Several scenarios were reviewed to determine if the Case 6 approach is valid, especially considering it does not represent intermediate operation, which has been proposed by Dominion and considered appropriate by the Department and represented in the draft permit. The validation began with a review of the ISO-based cases submitted by Dominion and statements by Mitsubishi regarding NSPS TTTT that were submitted by Dominion and represented as a basis for determining GHG BACT for the Greensville facility.

First, a review of the ISO cases (Cases 6, 7, 11, 14, 17, 20, 23, 29, 30, 43, 47, 50, and 51) indicates that several of these cases are likely very short-term scenarios and don't warrant consideration in an annual averaging period. Cases 14 and 43 were not considered because the output could be met using two turbine sets. Operating with 3 turbines at such a low load is considerably less efficient than operating two turbines. While several scenarios exist where these cases would be operated, they are expected to be short-term in nature. Cases 50 and 51 were excluded because they represent chiller operation at ISO conditions. This is an unlikely long-term scenario.

The remaining cases were reviewed to consider the validity of the approach taken. Assuming equal annual operation of the facility in 3-on-1 (Case 6), 2-on-1 (Case 17), and 1-on-1 (Case 20) modes, the emission rate is 868 lb/MWh after conversion from gross to net (2%), startup/shutdown (3%), 11.7% degradation. Assuming an equal amount of operation in all of the seven remaining cases, the maximum emission rate is 881 lb/MWh after conversion.

Dominion has represented Mitsubishi's statements in comments to EPA as representing the Greensville facility. In those comments, Mitsubishi states that even assuming intermediate operation and conservative and prudent assumptions, the 501J will operate at 861 lb/MWh. Such statements by the manufacturer warrant significant consideration when reviewing the many-faceted aspects of long-term operating scenarios. Data on the Warren facility's actual operation also indicates that the limits are achievable (converting to gross and accounting for degradation). Based on the review of Dominion's submitted data, including the representations in Mitsubishi's statements, the Department considers the limit of 890 lb/MWh net to be achievable if the facility is properly maintained and operated to minimize emissions.

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 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. The essence of the original draft permit condition remains unchanged, which allowed for 36 years of degradation from facility startup. As noted above, the revised GHG BACT limits are the most stringent permitted values. 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 Dominion's knowledge of maintenance schedules for similar facilities, a proposal of tiers in either six or twelve year durations was made. The Department considers the six year duration to best represent BACT performance for the Greensville facility while balancing the complexities of such an approach. To that end, the GHG BACT determination utilizes a consistent annual degradation rate of 0.325%, based on 11.7% degradation over 36 years. Dominion has represented the life of the unit to be 36 years so no additional degradation beyond that timeframe is considered appropriate.

	Btu/kWh net (HHV) output
Initial Test	6,457
Year 6	6,583
Year 12	6,709
Year 18	6,835
Year 24	6,961
Year 30	7,087
Year 31 and later	7,212

Degradation Period	Applicable limit in lb CO_{2e}/MWh net output
Years 1-6	812
Years 7-12	828
Years 13-18	843
Years 19-24	859
Years 25-30	875
Years 31 and later	890

b. Auxiliary Boiler 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.

c. Emergency generators and fire water pump
Add-on CO_2 controls are not technically feasible for emergency generators so BACT for the fire pump will be fuel-efficient design and a limit of 500 operating hours/yr.

d. Fugitive equipment leaks – Leaking piping components could contribute up to 240 tons of methane/year from natural gas (approximately 0.004% of the facility total GHG). Control techniques consist primarily of leak detection and repair, as well as prevention of leakage. Prevention includes minimizing venting, making sure connections are secure, and performing routine maintenance on the components. Leak detection and repair includes inspecting and testing to find leaks and then repairing them. These methods are all technically feasible and available. An audible/visual/olfactory (AVO) inspection can be quite effective in detecting leaks, when performed by trained plant personnel, due to the strong smell of the mercaptan odorizers in the natural gas. A review of the RBLC results in AVO 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 leak detection system.

2. <u>NO_x Control</u>

a. Combustion Turbines with duct-fired HRSG

i. Step 1 - Combustion turbines and the associated duct burners generate most of the NO_x emissions from the facility. The following control technologies were identified by Dominion 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

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.

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

SCONOX

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

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

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

SNCR/NSCR

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

DLN

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

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

Water/steam injection

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

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

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

XONON™, LoTOx™, THERMALLONOx™, and Pahlmann™

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

iii. Step 3 – Ranking of available NO_x controls

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 - BACT Determination: Selective Catalytic Reduction (SCR) and Dry Low-NO_x (DLN) Combustors

Dominion has proposed a combination of the remaining identified control options for NO_x: dry low-NO_x combustion and selective catalytic reduction (SCR). The proposed MHPS M501J CTG combustors 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 15 ppmvd at 15% O_2 when firing natural gas, the fuel proposed for use by Dominion. The draft permit proposes the additional use of SCR to control NO_x emissions from the CTs to the following level (at 15% 0_2):

- 2.0 ppmvd with or without duct burning

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

From 2007 to 2015, approximately 24 projects were permitted at 2.0 ppmvd at 15% O_2, including three LAER determinations. The proposed limits for the Greensville Plant are as stringent as any listed in EPA's RACT/BACT/LAER Clearinghouse (RBLC) for electric generating facilities.

b. Auxiliary boiler 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 and represent BACT for most sources.
   - SCR (approximately 82% efficient)

ii. Technical feasibility and availability of NO_x Control
   - All technologies are feasible and available

iii. Ranking of technologies
   - The best NO_x reduction could be achieved using both front end and add-on NO_x reduction technologies
   - Alternatively, low NO_x burners are the best front end technology for reducing NO_x emissions to 9 ppmvd.

iv. BACT determination
   - The use of SCR in conjunction with low NO_x burners has been determined to be economically infeasible for the auxiliary boiler and fuel gas heaters at costs exceeding $337,000 per ton for the boiler and $167,000 to $295,000 per ton for the fuel gas heaters.
   - DEQ concurs with Dominion that low NO_x burners are BACT for both units

c. Emergency Generators/Fire water pump
Although add-on controls such as SCR are used to control NO_x on larger generators, if necessary to meet national standards for emissions, the proposed emissions from the emergency units at this facility can meet these standards without add-on controls. The facility proposes a NO_x limit for the two 150 kW propane emergency generators of 2.0 g/hp-hr based on manufacturer estimates. The facility proposes a limit of NO_x+NMHC on the 3000 kW diesel emergency generator (EG-1) of 6.4 g/kW-hr on ULSD. And the 376 hp diesel fire water pump (FWP-1) has a proposed NO_x+NMHC limit of 3.0 g/hp-hr. This is in compliance with NSPS standards for newer diesel engines of those sizes and is considered BACT for those units.

3. Carbon Monoxide Control - Carbon monoxide 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. Combustion Turbines

i. Possible Control Technologies (Step 1)

   - Oxidation Catalyst
   - Good Combustion Practices

ii. Available and feasible (Step 2)

An oxidation catalyst 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. 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 PM_{10} and H_2SO_4 emissions.

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 or approximately 0.1 percent loss in power output for each 1.0 inch of water pressure loss.

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.

Good combustion practices consisting primarily of controlled fuel/air mixing and adequate temperature and gas residence time are used to minimize the formation of CO. Good combustion practices 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 good combustion practices to control the formation of CO, and oxidation catalyst as a post-combustion treatment.

iv. BACT (Step 4)

Dominion has proposed a combination of control options for CO: oxidation catalyst at 85% control and good combustion practices.
Performance of an oxidation catalyst can be affected by temperature, load, catalyst type, surface area, gas concentration, residence time, and other factors.

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

The lowest CO limits in the most recent BACT determinations in the RBLC are at 0.9 ppmvd at 15% O_2 without duct firing and 1.7 ppm with duct firing for the Kleen Energy Systems facility (Siemans SGT6-5000F turbine) and the CPV Towantic plant (GE 7HA.01 turbine) in Connecticut. The Towantic plant is not operating so no operational data is available to determine if this level is achievable at this plant on a long-term basis. It appears from the 5.0 ppm VOC BACT limit (which is the highest VOC limit in the RBLC for permits recently issued) at the Kleen Energy Systems facility, that the selected catalyst in the oxidation catalyst control, used to control CO and VOC, favored CO control over VOC control (BASF website: Camet® CO Oxidation Catalysts – CO vs VOC – The Catalysts Perspective). Additionally, this lower BACT limitation is only valid when operating at higher loads (60-100%).

Upon review of the lower BACT limit determinations, it was clear that the difference between Dominion's proposed limits and some of the lowest limits in the RBLC was the difference in assumed control efficiency. When a 90% control efficiency was used, Dominion's CO limits were 1.0 ppmvd without duct burning and 1.6 ppmvd with duct burning. These limits are considered BACT for the Greensville plant.

Compliance with the limits is to be based on a three-hour rolling average. This is different than the recently issued, similar, Brunswick County Power Station and the Warren County Power Station, permitted in 2011. Those permits include a one-hour average for CO. Due to the very stringent CO limit proposed for Greensville, 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 good combustion practices, constitute BACT for CO (3-hour rolling average) from the CTs as follows:

• 1.0 ppmvd without duct burning
• 1.6 ppmvd with duct burning

b. Auxiliary Boiler and Fuel Gas Heaters

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

ii. Technical feasibility and availability of CO Control (Step 2)
- Good combustion practices are feasible and available for these units
- Oxidation catalyst is feasible and available for these units

iii. Ranking of technologies (Step 3)
- Good combustion practices can result in emissions from the units (Dominion proposed 0.037 lb/MMBtu)
- Oxidation catalyst could reduce emissions further to about 0.006 lb/MMBtu

iv. BACT determination (Step 4)
- Oxidation catalyst used in conjunction with good combustion practices reduces CO emissions from the boiler by only 9 tons/yr at a cost of $10,000 per ton, and, for the fuel gas heaters, 1.1 tons/yr at $65,000 per ton, making it economically infeasible
- Good combustion practices results in CO emissions that are consistent with BACT at similar facilities. Dominion proposed a rate of 0.037 lb/MMBtu; however, several permits have been issued based on 0.035 lb/MMBtu. DEQ has determined that good combustion practices are BACT for CO from the auxiliary boiler and fuel gas heaters to a level of 6.6 lb/hr and 2.9 tons per (based on 0.035 lb/MMBtu).

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 stationary combustion units. Proper operation

and maintenance of the units, and burning of cleaner fuels can achieve CO levels that are comparable to BACT limitations for other, 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 3.5 g/kW-hr for the diesel emergency unit (EG-1), 2.6 g/hp-hr for the fire-water pump (FWP-1), and 4.0 g/hp-hr for the two propane units (EG-2 and EG-3).

4. SO_2 and 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 SO_2 and H_2SO_4 emissions from a natural gas combustion turbine. Flue gas desulfurization is only feasible on plants that produce much larger quantities of SO_2 and H_2SO_4 and would produce a significant pressure drop that would require an induced draft fan, potentially causing air/fuel mixing problems. The best low-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 Warren County Power Station had originally been permitted for 0.1 gr/100 dscf but the permit was revised to raise that after operation commenced. The sulfur content of the natural gas to be used in Greensville County can achieve 0.4 gr/100 dscf (levels across the country can range from 0.2 gr to 2.0 gr/100 dscf) and cannot be controlled by Dominion. DEQ concurs with the proposed use of pipeline quality natural gas to achieve the following BACT rates:

   - 0.00114 lb/MMBtu for SO_2
   - 0.00053 lb/MMBtu for H_2SO_4 without duct burning
   - 0.00060 lb/MMBtu for H_2SO_4 with duct burning

   b. Auxiliary boiler and fuel gas heaters
   The only feasible control for SO_2 and H_2SO_4 from the auxiliary boiler and fuel gas heaters is the use of pipeline quality natural gas.

   c. Emergency generators
   The use of ultra low sulfur diesel (ULSD or S15) in the diesel generators (S = 15 ppm) and the use of propane in the propane generators at 500 hrs/yr are considered BACT for SO_2 and H_2SO_4 from the emergency units.

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

   a. Combustion Turbines

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

      ii. Available and Feasible technologies (Step 2)

      An oxidation catalyst is a post-combustion technology that removes VOC from the exhaust gas stream after formation in the combustion turbine. In the presence of a catalyst, VOC will react with oxygen present in the exhaust stream, converting it to carbon dioxide and water vapor. The performance of an oxidation catalyst is affected by the VOCs that are actually emitted. No supplementary reactant is used in conjunction with an oxidation catalyst. An oxidation catalyst is considered to be available and technically feasible for application to this project.

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

iv. BACT (Step 4)
VOC emission rates for recently permitted (2007 to present) combined-cycle facilities are in the range of 0.3 ppmvd at 15% O_2 to 4.0 ppmvd at 15% O_2 as shown in Dominion's summary of EPA's RBLC. The emission limits at the low end are typically without duct burning and the higher end of the range reflect the higher emissions associated with duct burning.

The applicant has proposed to control VOC using good combustion practices 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 limits, based on 35% control by an oxidation catalyst, as follows, all at 15% O_2 and as CH_4 (calculated as a three-hour average):

- 1.0 ppmvd without duct burner firing
- 1.4 ppmvd with duct burner firing

The Chouteau facility located in Oklahoma is represented as a limit of 0.3 ppm VOC in the RBLC. However, this facility is not subject to a 0.3 ppm limit for VOC; the permit contains a pound/hour limit. As no compliance determination for the ppm value is required, the Chouteau facility is not comparable. The Brunswick County Power Plant was a similar facility and was permitted at 0.7 ppmvd without duct burner firing. Therefore, it is believed that the Greensville County Power Station can achieve this limit as well.

DEQ concurs that the use of good combustion control and an oxidation catalyst represent BACT for VOC control for the proposed combustion turbines. BACT emission limits will be as follows:

- 0.7 ppmvd without duct burner firing
- 1.4 ppmvd with duct burner firing

b. Auxiliary boiler and fuel gas heaters
i. List of control technologies (Step 1)
- Good combustion practices
- Oxidation catalyst

ii. Technical feasibility and availability of VOC Control (Step 2)
- Good combustion practices are feasible and available for these units
- Oxidation catalyst is feasible and available for these units

iii. Ranking of technologies (Step 3)
- Oxidation catalyst used in conjunction with good combustion practices would achieve the best control rate.
- Good combustion practices alone can result in emissions of VOC from the units of 0.005 lb/MMBtu

iv. BACT determination (Step 4)
VOC emissions from the boiler and fuel gas heaters without oxidation catalyst would be 0.005 lb/MMBtu. It would not be economically feasible to reduce emissions further with add-on controls. Good combustion practices results in VOC emissions that are consistent with BACT at similar facilities at 0.005 lb/MMBtu. DEQ concurs with Dominion that good combustion practices are BACT for VOC from the auxiliary boiler and fuel gas heaters.

c. Emergency generators and fire water pump
The use of good combustion practices, and operating at 500 hrs/yr are considered BACT for VOC from the emergency units. Emission of VOC from the two propane emergency generators (EG-2 and EG-3) is 1.0 g/hp-hr. The diesel generator (EG-1) will have a combined NOx+NMHC limit of 6.4 g/kW-hr and the Fire Water Pump (FWP-1) will have a combined NOx+NMHC limit of 3.0 g/hp-hr.

d. Fuel Tank
VOC emissions from the diesel fuel tank are estimated to be only 3.4 lbs/yr. The use of a fixed roof tank to hold diesel fuel is BACT for this type of unit.

6. Particulate Matter Controls (PM_{10} and $PM_{2.5}$, including condensable) – Particulate matter 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.

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 PM. Add-on controls are not available nor technically feasible for a combustion turbine.

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

iii. Ranking of 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 good combustion practices. 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. BACT for PM_{10} and $PM_{2.5}$ (Step 4)

The pipeline quality natural gas in this region contains 0.4 gr/100 dscf which impacts the PM_{10} and $PM_{2.5}$ emissions from fuel-burning (compared to the 0.1 gr/100 dscf to be used at the similar plant in Warren County, VA). In addition, the use of SCR and oxidation catalyst to control other air pollutants can contribute to PM_{10} and $PM_{2.5}$ emissions. For this reason, BACT from this facility will be slightly higher than BACT for PM_{10} and $PM_{2.5}$ from the Warren County plant but very similar to the Brunswick County plant. The applicant proposes the use of good combustion practices for the combustion turbines at the following BACT rates for PM_{10} and $PM_{2.5}$:

PM_{10}
• 9.2 lb/hr (0.0030 lb/MMBtu) without duct burner firing (average of three test runs)
• 14.1 lb/hr (0.0039 lb/MMBtu) with duct burner firing (average of three test runs)

$PM_{2.5}$
• 9.2 lb/hr (0.0030 lb/MMBtu) without duct burner firing (average of three test runs)
• 14.1 lb/hr (0.0039 lb/MMBtu) with duct burner firing (average of three test runs)

DEQ concurs that the use of good combustion practices represents BACT for PM_{10} and $PM_{2.5}$ control for the proposed combustion turbines.

b. Auxiliary Boiler and Fuel Gas Heaters
Particulate matter emissions from the boiler and fuel gas heaters are a combination of filterable and condensable particulate. Good combustion practices and limiting fuel use to only pipeline quality natural gas are proposed by the applicant as BACT for PM_{10} and $PM_{2.5}$ emissions from the auxiliary boiler and fuel gas heaters. DEQ agrees that this constitutes BACT for particulate emissions from the boiler and heaters. Short-term PM_{10} and $PM_{2.5}$ emissions from the auxiliary boiler and the fuel gas heaters will be limited to 0.007 lbs/MMBtu.

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

Unit	BACT Limit		
	PM (filterable only)	PM_{10}	$PM_{2.5}$
EG-1	0.2 g/kW-hr	0.4 g/kW-hr	0.4 g/kW-hr
EG-2		0.019 g/hp-hr	0.019 g/hp-hr
EG-3		0.019 g/hp-hr	0.019 g/hp-hr
FWP-1	0.15 g/hp-hr	0.30 g/hp-hr	0.30 g/hp-hr

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

i. Auxiliary Equipment Cooler
BACT for PM from the AEC will be to keep dissolved solids below 300 mg/l and to achieve a drift rate of 0.01 percent of the circulating water flow (equivalent to 0.0025 TPY of PM_{10} and $PM_{2.5}$)

ii. Inlet Chillers

BACT for PM from the Inlet Chillers will be to keep dissolved solids below 1,500 mg/l and to achieve a drift rate of 0.0005 percent of the circulating water flow (equivalent to 0.013 TPY of PM_{10} and 4.8 x 10^{-4} TPY of $PM_{2.5}$.

7. Startup/shutdown – BACT applies during startup and shutdown (SU/SD) of the turbines. During SU/SD, some post-combustion controls are not working at the optimum level of control, however, during these periods, the turbines and duct burners are also not operating at their highest output and other emissions may be reduced for that reason. Dominion 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. Good combustion practices including controlling the fuel/air mixing, temperature, and gas residence time during combustion to minimize emissions. Dominion submitted BACT for SU/SD for the turbines as follows:
   a. GHG – No alternate BACT was proposed since the BACT limitations could be met during SU/SD.

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

   c. CO - Technically feasible CO controls during SU/SD include oxidation catalyst, DLN (which can result in lowering CO as well as NOx), and good combustion practices. Of these, oxidation catalyst is most effective, followed by good combustion practices 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. Although VOC controls would be similar to CO controls, the effectiveness of these controls could be minimal. Dominion proposes limitations on the duration of SU/SD events to minimize VOC emissions during SU/SD.

   f. Add-on controls for PM, like electrostatic precipitators or baghouses are usually not applied to natural gas plants, especially for alternative operating scenarios such as SU/SD. So the only feasible control for PM would be the use of clean fuel, such as natural gas, followed by good combustion practices. Dominion proposes limitations on the duration of SU/SD events to minimize PM emissions during SU/SD.

8. Alternative Operating Scenarios
   a. 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 could be met during tuning.

      ii. NO_x - Technically feasible NOx controls during tuning include SCR, DLN, and good combustion practices. Of these, SCR is most effective, followed by good combustion practices and DLN. A combination of these controls will be employed to minimize NO_x during tuning. The lb/turbine/calendar day will be limited for NOx 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 good combustion practices. Of these, oxidation catalyst is most effective, followed by good combustion practices and

DLN. A combination of these controls will be employed to minimize CO during tuning. The lbs/turbine/day will be limited for CO 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. Dominion proposes limitations on the duration of tuning events to minimize VOC emissions during tuning.

vi. PM - Add-on controls for PM, like electrostatic precipitators or baghouses are usually not 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 good combustion practices. Dominion also proposes limitations on the duration of tuning events to minimize PM emissions during tuning.

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

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

ii. NO_x - Technically feasible NO_x controls during water washing include SCR, DLN, and good combustion practices. Of these, SCR is most effective, followed by good combustion practices and DLN. A combination of these controls will be employed to minimize NO_x during water washing. The lb/turbine/calendar day will be limited for NO_x during water washing.

iii. CO - Technically feasible CO controls during water washing include oxidation catalyst, DLN (which can result in lowering CO as well as NO_x), and good combustion practices. Of these, oxidation catalyst is most effective, followed by good combustion practices and DLN. A combination of these controls will be employed to minimize CO during water washing. The lbs/turbine/day will be limited for CO during water washing.

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

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

vi. PM - Add-on controls for PM, like electrostatic precipitators or baghouses are usually not applied to natural gas plants, especially for alternative operating scenarios such as water washing. So the only feasible control for PM would be the use of clean fuel, such as natural gas, followed by good combustion practices. Dominion proposes limitations on the duration of water washing events to minimize PM emissions during water washing.

Table 4 below summarizes BACT for normal operation for the facility:

Pollutant	Primary BACT	Control	Compliance
NO_x	Turbine 2.0 ppmvd @ 15% O_2 (1-hour avg.)	DLN burners SCR	Annual fuel throughput Stack test NOx CEMS
	Auxiliary Boiler and fuel gas heaters 9 ppmvd (0.011 lbs/MMBtu)	DLN burners	Annual fuel throughput Stack test
	Emergency Generators EG-1 6.4 g/kW-hr NOX+NMHC FWP-1 4.0 g/kW-hr NOX+NMHC EG-2&3 2.0 g/hp-hr	Good combustion practices	Annual hours of operation
SO_2	Turbine 0.00114 lb/MMBtu	Low sulfur fuel	Fuel monitoring, stack test
	Auxiliary boiler and fuel gas heaters 0.00114 lb/MMBtu	Low sulfur fuel	Fuel monitoring
	Emergency generators 0.00154 lb/MMBtu (diesel) 0.00059 lb/MMBtu (propane)	ULSD fuel with 15 ppm S (diesel units) or propane fuel (propane units)	Fuel certification and hours of operation
H_2SO_4	Turbine 0.00053 lb/MMBtu without DB 0.00060 lb/MMBtu with DB	Low sulfur fuel	Fuel monitoring
	Auxiliary boiler and fuel gas heaters 0.0000876 lb/MMBtu	Pipeline quality natural gas	Fuel monitoring
	Emergency generators 0.00012 lb/MMBtu (diesel) 0.00005 lb/MMBtu (propane)	ULSD fuel with 15 ppm S (diesel units) or propane fuel (propane units)	Fuel monitoring
CO	Turbine 1.0 ppmvd without DB (3-hour avg.) 1.6 ppmvd with DB (3-hour avg.)	Oxidation catalyst Good combustion practices	CO CEMS
	Auxiliary boiler and fuel gas heaters 6.6 lbs/hr (0.035 lb/MMBtu)	Clean fuel and good combustion practices	Stack test
	Emergency generators 2.6 g/hp-hr (diesel) 4.0 g/kW-hr (propane)	Good combustion practices	Fuel monitoring
PM_{10}	Turbine 9.2 lbs/hr (0.0030 lb/MMBtu) without DB (average of three test runs) 14.1 lbs/hr (0.0039 lb/MMBtu) with DB (average of three test runs)	Low sulfur/carbon fuel and good combustion practices	Stack test
	Auxiliary boiler and fuel gas heaters 0.007 lb/MMBtu	Low sulfur/carbon fuel and good combustion practices	Fuel throughput
	Emergency generators EG-1 0.4 g/kW-hr FWP-1 0.30 g/hp-hr EG2&3 0.019 g/hp-hr	Low sulfur fuel and good combustion practices	Hours of operation
	Inlet Chillers Drift rate of 0.0005% of circulating water flow and TDS of no more than 1500 mg/l	Low total dissolved solids (TDS) and drift eliminators	Weekly water quality testing for TDS
	Auxiliary Cooler Drift rate of 0.01% and TDS content of no more than 300 mg/l	Low TDS	Weekly water quality testing for TDS
$PM_{2.5}$	Turbine 9.2 lbs/hr (0.0030 lb/MMBtu) without DB (average of three test runs) 14.1 lbs/hr (0.0039 lb/MMBtu) with DB (average of three test runs)	Low sulfur/carbon fuel and good combustion practices	Stack test
	Auxiliary boiler and fuel gas heaters 0.007 lb/MMBtu	Low sulfur/carbon fuel and good combustion practices	Fuel throughput
	Emergency generators EG-1 0.4 g/kW-hr FWP-1 0.30 g/hp-hr EG2&3 0.019 g/hp-hr	Low sulfur fuel and good combustion practices	Hours of operation
	Inlet Chillers Drift rate of 0.0005% of circulating water flow and TDS of no more than 1500 mg/l	Low total dissolved solids (TDS) and drift eliminators	Weekly water quality testing for TDS
	Auxiliary Cooler Drift rate of 0.01% and TDS content of no more than 300 mg/l	Low TDS	Weekly water quality testing for TDS

Pollutant	Primary BACT	Control	Compliance
VOC	Turbine 0.7 ppmvd without DB 1.4 ppmvd with DB	Oxidation catalyst Good combustion practices	stack test and CO CEMS compliance
	Auxiliary boiler and fuel gas heater 0.005 lb/MMBtu	Good combustion practices, operator training, and proper design, construction and maintenance	Fuel throughput
	Emergency generators FWP-1, EG-1 (see NOx + NMHC limit) EG-2&3 1.0 g/hp-hr	Good combustion practices	Hours of operation
CO_2e	Turbine 7,212 Btu/kW (HHV) net after 31 years 890 lb CO_2e/MWh after 31 years	Energy efficient combustion practices and low GHG fuels	ASME Performance Test Code on Overall Plant Performance (PTC 46) and CO_2 CEMS (Part 75) and maintenance.
	Auxiliary boiler and fuel gas heaters 117.1 lb/MMBtu	Natural gas and fuel and high efficiency design and operation	Manufacturer specifications and maintenance.
	Emergency Units Diesel units 163.6 lb/MMBtu Propane units 136.1 lb/MMBtu	High efficiency operation, and for propane units, good combustion practices and demonstrated compliance with NSPS JJJJ	fuel usage monitoring
	Electrical Circuit breakers 0.5% leakage rate	Enclosed-pressure type breaker and leak detection	Audible alarm with decreased pressure.
	Fugitive leaks from natural gas piping components	AVO monitoring and leak repair	recordkeeping

Table 5 below summarizes BACT for alternative operating scenarios:

Pollutant	Startup/Shutdown	Maintenance Activities (Tuning/Water Washing)
NOx	cold start event - 1,231 lb/turbine, warm start event - 395 lb/turbine, hot start event - 148 lb/turbine shutdown event - 65 lb/turbine	648 lb/turbine/day
CO	cold start event - 6,944 lb/turbine, warm start event - 3,316 lb/turbine, hot start event - 1,771lb/turbine shutdown event - 1,004 lb/turbine	436 lb/turbine/day
VOC	Good combustion practices, cold start duration - 436 minutes, warm start duration - 166 minutes, hot start duration - 84 minutes, shutdown duration - 30 minutes	18 hours per day tuning & 96 hours per year, 60 minutes per wash event & 52 hours per year
$PM/PM_{10}/PM_{2.5}$	Low sulfur pipeline quality natural gas containing maximum fuel sulfur content 0.4 gr/100 scf,, Good combustion practices, cold start duration - 436 minutes, warm start duration - 166 minutes, hot start duration - 84 minutes, shutdown duration - 30 minutes	Low sulfur pipeline quality natural gas containing maximum fuel sulfur content 0.4 gr/100 scf, 18 hours per day tuning & 96 hours per year, 60 minutes per wash event & 52 hours per year
SO_2	No alternate BACT limit requested Low sulfur pipeline quality natural gas containing maximum fuel sulfur content 0.4 gr/100 scf, 0.00114 lb/MMBtu	No alternate BACT limit requested Low sulfur pipeline quality natural gas containing maximum fuel sulfur content 0.4 gr/100 scf, 0.00114 lb/MMBtu
Sulfuric Acid Mist	No alternate BACT limit requested Low sulfur pipeline quality natural gas containing maximum fuel sulfur content 0.4 gr/100 scf, 0.00053 lb/MMBtu 0.00060 lb/MMBtu with duct burner	No alternate BACT limit requested Low sulfur pipeline quality natural gas containing maximum fuel sulfur content 0.4 gr/100 scf, 0.00053 lb/MMBtu without duct burner 0.00060 lb/MMBtu with duct burner
Greenhouse Gases	No alternate BACT limit requested	No alternate BACT limit requested

The proposed control strategies are considered to be the Best Available Control Technology (BACT) for this source type and are more stringent than NSPS standards.

IV. Initial Compliance Determination

A. Testing – stack testing is required for NO_x, SO_2, CO, VOC, PM_{10}, and $PM_{2.5}$ from the turbines and NO_x and CO from the auxiliary boiler and fuel gas heaters to show compliance with the BACT limits. An initial compliance test 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 standard cubic feet. Alternatively, per 40 CFR 60.4370, the permit allows Dominion 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.

V. Continuing Compliance Determination

A. CEMS – will be required for NO_x (NSPS) and is also proposed for CO. 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 Dominion to conduct extensive, continuous monitoring of key operational parameters on the control devices to assure proper operation and performance. Fuel tracking for the turbines (including fuel sulfur content), auxiliary boiler, fuel gas heaters, and emergency units is required to show compliance with other emission limits.

The permit will require CO_2 CEMS for CO_2 monitoring but Part 98 factors can be used for N_2O and CH_4 monitoring.

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

a. Annual hours of operation of the emergency fire water pump (FWP-1) and emergency generators (EG-1, EG-2, and EG-3) for emergency purposes and for maintenance checks and readiness testing, calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months;

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

c. Monthly and annual throughput of natural gas to the three combustion turbines and associated duct burners (CT-1, CT-2 and 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;

d. Monthly emissions calculations for PM_{10}, $PM_{2.5}$ and VOC from the combined cycle combustion turbines and associated duct burners (CT-1, CT-2, CT-3) using calculation methods approved by the Piedmont Regional Office to verify compliance with the ton/yr emissions limitations in Condition 41;

e. Monthly and annual records of plant net electrical energy output used in the demonstrations of compliance required in Condition 40;

f. Monthly and annual emissions of CO_2 and CO_2e, calculated monthly as the sum of each consecutive 12-month period;

g. Monthly and annual calculations of CO_2e emission rates (lb/MWh net) to demonstrate compliance with the requirements of Condition 40. Compliance for the consecutive 12-month period shall be demonstrated monthly as required in Condition 40;

h. Monthly and annual throughput of natural gas to the auxiliary boiler (B-1) and the fuel gas heaters (FGH1 through FGH-6), 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;

i. Fuel quality records for natural gas combusted in the combustion turbine and associated duct burner (CT-1, CT-2 and CT-3);

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

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

l. Records of alternative operating scenarios as required by Conditions 10 and 11;

m. 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;

n. Weekly logs of dissolved solids content of cooling water to the four inlet coolers (IC-1 through IC-4) and the auxiliary equipment chiller (AEC-1).

o. Scheduled and unscheduled maintenance, and operator training.

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

q. Manufacturer’s instructions for proper operation of equipment.

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

s. Records showing the circuit breakers are operating in accordance with the manufacturer’s specifications (see Condition 24).

C. Further Testing

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

b. After the initial test for heat rate of the power block, an additional test is required every five years.

c. After the initial test for PM10, PM2.5 and, VOC, additional testing is required every five years.

VI. Public Participation

The applicant held a public information session on February 19, 2015 at the County Government Building in Emporia, Greensville County to provide the community with information about the project.

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

An information meeting and public hearing is scheduled to be held on March 16, 2016 at the Greensville 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:_____________________ Date: ____________________

Reviewing Engineer:_____________________ Date: ____________________

Attachments:

Appendix A – Calculation sheets
Appendix B – Modeling Memo