TENTATIVE AGENDA
STATE AIR POLLUTION CONTROL BOARD MEETING

FRIDAY, JUNE 21, 2019

VIRGINIA CROSSINGS HOTEL & CONFERENCE CENTER
HANOVER ROOM, MADISON BUILDING
1000 VIRGINIA CENTER PARKWAY
GLEN ALLEN, VIRGINIA 23059

Convene – 10:00 a.m.

Agenda Item	**Presenter**	**Tab**
Minutes		A
Prevention of Significant Deterioration Permit - BALICO/ Chickahominy Power Project (Registration #52610) Draft Final Permit (with track changes- Draft Final Permit(clean copy) Permit Engineering Analysis Summary of and Response to Public Comments Summary of DEQ Changes to the Draft Permit List of Commenters and Sample of Comments [Note: Public comment from those who commented at the public hearing or during the public comment period will be accepted before Board action on the draft permit - see comment policy below for Case Decisions, especially highlighted text.]	Dowd	B C D E F G H
High Priority Violations Report	Nicholas	I
Public Forum (time for this item not to exceed 45 minutes)		
Division Director Report	Dowd	
Public Participation Process Discussions		
Future Meetings (September 20 and December 6)		
Election of Officers		

ADJOURN

NOTE: The Board reserves the right to revise this agenda without notice unless prohibited by law. Revisions to the agenda include, but are not limited to, scheduling changes, additions or deletions. Questions on the latest status of the agenda should be directed to Cindy M. Berndt at (804) 698-4378.

PUBLIC COMMENTS AT STATE AIR POLLUTION CONTROL BOARD MEETINGS: The Board encourages public participation in the performance of its duties and responsibilities. To this end, the Board has adopted public participation procedures for regulatory action and for case decisions. These procedures establish the times for the public to provide appropriate comment to the Board for its consideration.

For REGULATORY ACTIONS (adoption, amendment or repeal of regulations), public participation is governed by the Administrative Process Act and the Board's Public Participation Guidelines. Public comment is accepted during the Notice of Intended Regulatory Action phase (minimum 30-day comment period) and during the Notice of Public Comment Period on Proposed Regulatory Action (minimum 60-day comment period). Notice of these comment periods is announced in the Virginia Register, by posting to the Department of Environmental Quality and Virginia Regulatory Town Hall web sites and by mail to those on the Regulatory Development Mailing List. The comments received during the announced public comment periods are summarized for the Board and considered by the Board when making a decision on the regulatory action.

For CASE DECISIONS (issuance and amendment of permits), the Board adopts public participation procedures in the individual regulations which establish the permit programs. As a general rule, public comment is accepted on a draft permit for a period of 30 days. In some cases a public hearing is held at the conclusion of the public comment period on a draft permit. In other cases there may an additional comment period during which a public hearing is held.

In light of these established procedures, the Board accepts public comment on regulatory actions and case decisions, as well as general comments, at Board meetings in accordance with the following:

REGULATORY ACTIONS: Comments on regulatory actions are allowed only when the staff initially presents a regulatory action to the Board for final adoption. At that time, those persons who commented during the public comment period on the proposal are allowed up to 3 minutes to respond to the summary of the comments presented to the Board. Adoption of an emergency regulation is a final adoption for the purposes of this policy. Persons are allowed up to 3 minutes to address the Board on the emergency regulation under consideration.

CASE DECISIONS: Comments on pending case decisions at Board meetings are accepted only when the staff initially presents the pending case decision to the Board for final action. At that time the Board will allow up to 5 minutes for the applicant/owner to make his complete presentation on the pending decision, unless the applicant/owner objects to specific conditions of the decision. In that case, the applicant/owner will be allowed up to 15 minutes to make his complete presentation. The Board will then allow others who commented at the public hearing or during the public comment period up to 3 minutes to exercise their rights to respond to the summary of the prior public comment period presented to the Board. No public comment is allowed on case decisions when a FORMAL HEARING is being held.

POOLING MINUTES: Those persons who commented during the public hearing or public comment period and attend the Board meeting may pool their minutes to allow for a single presentation to the Board that does not exceed the time limitation of 3 minutes times the number of persons pooling minutes, or 15 minutes, whichever is less.

NEW INFORMATION will not be accepted at the meeting. The Board expects comments and information on a regulatory action or pending case decision to be submitted during the established public comment periods. However, the Board recognizes that in rare instances new information may become available after the close of the public comment period. To provide for consideration of and ensure the appropriate review of this new information, persons who commented during the prior public comment period shall submit the new information to the Department of Environmental Quality (Department) staff contact listed below at least 10 days prior to the Board meeting. The Board's decision will be based on the Department-developed official file and discussions at the Board meeting. In the case of a regulatory action, should the Board or Department decide that the new information was not reasonably available during the prior public comment period, is significant to the Board's decision and should be included in the official file, the Department may announce an additional public comment period in order for all interested persons to have an opportunity to participate.

PUBLIC FORUM: The Board schedules a public forum at each regular meeting to provide an opportunity for citizens to address the Board on matters other than those on the agenda, pending regulatory actions or pending case decisions. Those persons wishing to address the Board during this time should indicate their desire on the sign-in cards/sheet and limit their presentations to 3 minutes or less.

The Board reserves the right to alter the time limitations set forth in this policy without notice and to ensure comments presented at the meeting conform to this policy.

Department of Environmental Quality Staff Contact: Cindy M. Berndt, Director, Regulatory Affairs, Department of Environmental Quality, 1111 East Main Street, Suite 1400, P.O. Box 1105, Richmond, Virginia 23218, phone (804) 698-4378; fax (804) 698-4346; e-mail: cindy.berndt@deq.virginia.gov.

Additional Meeting Information:

- Attendees are not entitled to be disorderly or disrupt the meeting from proceeding in an orderly, efficient, and effective fashion. Disruptive behavior may result in a recess or removal from the meeting.
- Possession or use of any device that may disrupt the conduct of business is prohibited, including but not limited to: voice-amplification equipment; bullhorns; blow horns; sirens, or other noise-producing devices; as well as signs on sticks, poles or stakes; or helium-filled balloons.
- Attendees shall not block or gather in exits, doors, or aisles.
- All attendees are asked to be respectful of all speakers.
- Rules will be enforced fairly and impartially not only to ensure the efficient and effective conduct of business, but also to ensure no interference with the business of the hotel, its employees and guests.
- All violators are subject to removal.

MINIBOOK

PREVENTION OF SIGNIFICANT DETERIORATION (PSD) PERMIT FOR BALICO LLC/ – CHICKAHOMINY POWER, REGISTRATION NO. 52610 - PUBLIC PARTICIPATION REPORT AND REQUEST FOR BOARD ACTION

INTRODUCTION

Balico LLC / Chickahominy Power (BCP) has proposed to construct and operate a new natural gas-fired combined-cycle electric power generating facility in Charles City County (the "Chickahominy Power Station" (CPS)) with a nominal generating capacity of 1650 megawatts (MW) at ISO (International Organization for Standardization) conditions. Prevention of Significant Deterioration (PSD) permitting is triggered because, as a fossil fuel-fired steam electric plant of more than 250 million British thermal units (MMBtu) per hour heat input capacity, the proposed facility is a major stationary source under 9 VAC 5 Chapter 80, Article 8. The proposed site is an area of Charles City County about 10 miles southeast of the Richmond International Airport.

BCP submitted its initial air permit application on February 22, 2017. The application was deemed complete on January 10, 2019 when an updated application was submitted.

The applicant held the required informational briefing on May 17, 2017. DEQ's public hearing for the proposed permit was held March 5, 2019. The public comment period was opened January 31, 2019 and ended March 20, 2019.

Staff analysis has shown that BCP has met the requirements of the PSD permitting regulations at 9 VAC 5 Chapter 80, Part II, Article 8, and that the proposed facility, operating in accordance with the conditions of the proposed permit, will not cause or significantly contribute to an exceedance of ambient air quality standards or PSD increments.

PERMIT APPLICATION REVIEW

BCP has applied for a permit to construct and operate a natural gas-fired combined cycle electric power generating facility with a nominal generating capacity of 1650 megawatts (MW). The proposed facility is comprised of three combustion turbine (CT) generators, each having a heat recovery steam generator (HRSG) driving a steam turbine (ST) for additional electricity generation. The CT-HRSG arrangement is commonly called combined cycle. The proposed facility also includes two auxiliary boilers, an emergency diesel firewater pump, an emergency diesel generator, three fuel gas heaters, circuit breakers (total capacity of 22,800 pounds of sulfur hexafluoride), and two distillate oil storage tanks.

The pollutants of concern from the combined-cycle units are nitrogen oxides (NO_X), carbon monoxide (CO), volatile organic compounds (VOC), greenhouse gases (GHG), sulfur dioxide (SO_2), sulfuric acid mist (H_2SO_4), particulate matter (PM), particulate matter having an aerodynamic diameter equal to or less than ten microns (PM_{10}), and particulate matter having an aerodynamic diameter equal to or less than 2.5 microns ($PM_{2.5}$). NO_X from the units will be controlled using dry low-NO_X combustion and selective catalytic reduction (SCR). CO and VOC will be controlled by oxidation catalyst. The total emissions from the proposed project are shown in Table 1.

Table 1. Total emissions from proposed CPS

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

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

The proposed site for the CPS is a 185-acre parcel ESE of the intersection of State Route 106 (Roxbury Rd.) and State Route 685 (Chambers Rd.) and adjacent to the Dominion Energy Chickahominy Substation. There are no Class I areas (areas such as national parks or wildlife sanctuaries) within 100 km of the proposed facility. The Federal Land Managers were notified of the project but none requested that a Class I Air Quality Related Values modeling analysis be included as part of the permit review.

DEPARTMENT ANALYSIS

Criteria Pollutants

Applicability of PSD review is evaluated on a pollutant-specific basis. A new stationary source that has the potential to emit (PTE) major quantities of a pollutant (i.e., a fossil fuel-fired steam electric plant over 250 MMBtus per hour heat input having the PTE to emit over 100 tons per year of a pollutant) is subject to PSD review for any regulated NSR pollutant with the PTE over the PSD significant rate in 9 VAC 5-80-1615 C. Pollutants exceeding PSD major or PSD significance levels for the proposed BCP project are NO_X, CO, VOC, GHG, PM, PM_{10}, $PM_{2.5}$, SO_2 and sulfuric acid mist. GHG emissions (CO_2 equivalents or CO_2e) exceeded the PSD threshold established by EPA's PSD and Title V Greenhouse Gas Tailoring Rule, adopted in 9 VAC 5-85-50 (75,000 tons per year) and so, too, are subject to PSD review.

Emissions of pollutants subject to PSD review are required to undergo a top-down Best Available Control Technology (BACT) analysis and air quality analyses.

BACT

Pollutants subject to a PSD review from a proposed facility must undergo a rigorous “top-down” BACT analysis. The “top-down” method provides that all available control technologies be ranked in descending order of control effectiveness. The applicant first examines the most stringent or “top” alternative. The top alternative is established as BACT unless the applicant demonstrates that technical considerations or energy, environmental, or economic impacts justify that the most stringent technology is not feasible. For the proposed BCP project, the pollutants subject to BACT are NO_X, CO, VOC, PM, PM_{10}, $PM_{2.5}$, CO_2e, SO_2 and sulfuric acid mist.

A summary of the BACT analysis is presented in Table 2.

Table 2 – BACT Summary

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

Pollutant	Equipment and Primary BACT	Control	Compliance
CO	Turbines This limit applies at all times except SU/SD and tuning events: 1.0 ppmvd @15% O_2 (3-hour avg) Limits during SU/SD for each event: Cold start: 444 lb/turbine Warm start: 396 lb/turbine Hot start: 252 lb/turbine shutdown: 156 lb/turbine Limits during tuning: 214 lb/turbine/calendar day	Oxidation catalyst GCPs	CO CEMS Annual limit for tuning events
CO	Auxiliary Boilers (each) 3.2 lb/hr (0.037 lbs/MMBtu) Fuel gas heaters 0.5 lb/hr (0.037 lb/MMBtu)	Clean fuel and GCPs	Stack test
CO	Emergency generators 2.6 g/hp-hr	Proper operation and maintenance, clean fuel	Annual hours of operation
VOC	Turbines This limit applies at all times except SU/SD and tuning events: 0.7 ppmvd @15% O_2 (3-hour avg) Limits during SU/SD for each event: Cold start: 216 lb/turbine Warm start: 216 lb/turbine Hot start: 168 lb/turbine shutdown: 216 lb/turbine Tuning events are limited to no more than 18 consecutive hours and 96 hours per year.	Oxidation catalyst GCPs	Stack test and CO CEMS correlation Tracking duration of SU/SD and maintenance events. Annual limit for tuning events
VOC	Auxiliary boilers and fuel gas heaters 0.005 lb/MMBtu	GCPs	Annual fuel throughput
VOC	Emergency generators FWP-1 0.11 g/hp-hr EG-1 1.0 g/hp-hr	GCPs	Annual hours of operation
H_2SO_4	Turbines These limits apply at all times 0.0012 lb/MMBtu	Low sulfur fuel with a sulfur content of no more than 0.4 gr/100 scf on an annual average.	Fuel monitoring
H_2SO_4	Auxiliary boilers and fuel gas heaters	Pipeline quality natural gas with a sulfur content of no more than 0.4 gr/100 scf on an annual average.	Fuel monitoring
H_2SO_4	Emergency generators 0.000118 lb/MMBtu	ULSD fuel with 15 ppm S	Fuel monitoring
SO_2	Turbines This limit applies at all times 0.00114 lb/MMBtu	Low sulfur fuel	Fuel monitoring, stack test
SO_2	Auxiliary boilers 0.00114 lb/MMBtu	Pipeline quality NG with a sulfur content of no more than 0.4 gr/100 scf on an annual basis.	Fuel monitoring
SO_2	Emergency generators 0.00154 lb/MMBtu	ULSD fuel with 15 ppm S	Fuel certification and annual hours of operation
PM	Turbines These limits apply at all times except during tuning events: 0.0052 lb/MMBtu Tuning events are limited to no more than 18 consecutive hours and 96 hours per year.	Low sulfur/ash fuel (pipeline quality NG with no more than 0.4 gr/100scf on an annual average) and GCPs	Stack test Annual limit for tuning events

Pollutant	Equipment and Primary BACT	Control	Compliance
PM	Auxiliary boilers and fuel gas heaters 0.007 lbs/MMBtu Auxiliary boilers 0.6 lbs/hr	Low sulfur/carbon fuel and GCPs	Annual fuel throughput
PM	Emergency generators EG-1 0.15 g/hp-hr FWP-1 0.15 g/hp-hr	Low sulfur fuel and GCPs	Annual hours of operation
PM_{10}	Turbines These limits apply at all times except during tuning events: 12.3 lbs/hr (0.0052 lb/MMBtu) average of three test runs Tuning events are limited to no more than 18 consecutive hours and 96 hours per year.	Low sulfur/ash fuel (pipeline quality NG with no more than 0.4 gr/100scf on an annual average) and GCPs Minimizing duration of maintenance events.	Stack test Annual limit for tuning events
PM_{10}	Auxiliary boilers and fuel gas heaters 0.007 lbs/MMBtu Auxiliary boilers 0.6 lbs/hr	Low sulfur/carbon fuel and GCPs	Annual fuel throughput
PM_{10}	Emergency generators EG-1 0.15 g/hp-hr FWP-1 0.15 g/hp-hr	Low sulfur fuel and GCPs	Annual hours of operation
$PM_{2.5}$	Turbines These limits apply at all times except during tuning events: 12.3 lbs/hr (0.0052 lb/MMBtu) average of three test runs Tuning events are limited to no more than 18 consecutive hours and 96 hours per year.	Low sulfur/ash fuel (pipeline quality NG with no more than 0.4 gr/100scf on an annual average) and GCPs Minimizing duration of maintenance events.	Stack test Annual limit for tuning events
$PM_{2.5}$	Auxiliary boilers and fuel gas heaters 0.007 lbs/MMBtu Auxiliary boilers 0.6 lbs/hr	Low sulfur/carbon fuel and GCPs	Annual fuel throughput
$PM_{2.5}$	Emergency generators EG-1 0.15 g/hp-hr FWP-1 0.15 g/hp-hr	Low sulfur fuel and GCPs	Annual hours of operation

Toxic Pollutants/Hazardous Air Pollutants (HAPs)

40 CFR 63 Subpart YYYY, National Emissions Standards for HAPs from Stationary Combustion Turbines, applies to CTs located at major HAP sources. The HAP emissions from the proposed CPS do not exceed major source thresholds for HAPs (i.e., 10 tons per year of a single HAP or 25 tons per year of all HAPs combined). Accordingly, the proposed facility is not subject to the MACT standard.

Since the facility is not subject to the MACT standard, the emissions of toxic pollutants were examined for applicability to the toxic pollutant standards in 9 VAC 5-60-300. As a result, BCP conducted an evaluation of toxic pollutants and compared proposed emission rates to the emission standards in 9 VAC 5-60-300. This evaluation includes a modeling analysis for eight pollutants for which permitted emissions were above the exemption levels in 9 VAC 5-60-300 (acrolein, beryllium, lead compounds, formaldehyde, cadmium, chromium, mercury, and nickel). The modeling analysis indicates that the impacts of the eight pollutants are well below their applicable Significant Ambient Air Concentrations (SAACs).

Testing

The permit requires initial stack tests for NO_X, SO_2, CO, PM, PM_{10}, $PM_{2.5}$, and VOC from the combined-cycle units. Periodic stack tests will continue for PM_{10}, $PM_{2.5}$, VOC (every five years), and SO_2 (annually). Initial stack tests for NO_x and CO from the auxiliary boiler and fuel gas heaters is also required. Additional stack tests can be requested by DEQ.

BCP must conduct an initial power block heat rate test to determine compliance with the heat rate in the permit to demonstrate efficient operation of the turbines and associated HRSG. Periodic (every six years) power block heat rate tests are also required.

Visible emissions evaluations (VEEs), concurrent with the initial CT, auxiliary boiler, and fuel gas heaters stack tests, are required by the permit.

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 grains or less of total sulfur per 100 standard cubic feet. Alternatively, per 40 CFR 60.4370, the permit allows BCP 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 diesel generator and fire water pump.

Monitoring

The permit requires that the CT stacks be equipped with Continuous Emission Monitoring Systems (CEMS) meeting the requirements of 40 CFR Part 75 (Acid Rain Program) for NO_X and SO_2 (unless an alternative method of determining SO_2 emissions has been approved for that purpose) and meeting the requirements of 40 CFR Part 60 for CO. In addition to the CEMS, the permit requires BCP to conduct extensive, continuous monitoring of key operational parameters on the control devices to assure proper operation and performance.

Recordkeeping

The permit requires BCP to keep records of all CEMS results; control device parametric monitoring results; results of fugitive leak inspections; monthly fuel throughput for the turbines, auxiliary boiler and fuel gas heaters; net electrical energy output of the plant; calculations of CO_2 monthly emissions; and the frequency and duration of any SU/SD or tuning events. BCP is further required by the permit to keep records of all fuel certifications and testing results, and monthly operating hours for the emergency generator and fire water pump.

Reporting

BCP must provide quarterly reports to DEQ of CEMS results, including whether or not excess emissions have occurred, and emissions associated with alternative operating scenarios. BCP is required by the permit to notify DEQ of commencement of construction, facility start-up, and to provide 30-day prior notice for each performance test conducted, and the results of performance tests.

Air Quality Analyses

In addition to the BACT review, PSD regulations require an air quality analysis be performed that demonstrates the projected air emissions from the proposed facility will neither cause or significantly contribute to a violation of any applicable National Ambient Air Quality Standard

(NAAQS) or PSD increment. In addition, PSD regulations require that an additional impact analysis consisting of a soil and vegetation analysis, a growth analysis, and a visibility impairment analysis be conducted.

Prior to conducting the analyses, BCP submitted a protocol outlining the intended methodology and input data for both areas. DEQ staff reviewed and approved the protocol. Based on DEQ's review of the NAAQS and PSD increment analyses, the proposed project does not cause or significantly contribute to a predicted violation of any applicable NAAQS or Class I and Class II area PSD increment.

The DEQ's review of the required air quality analyses for the CPS for both Class I and Class II PSD areas is included in the Board book. This document also includes DEQ's review of an additional impact analysis consisting of a soil and vegetation analysis, a growth analysis, and a visibility impairment analysis.

PUBLIC PARTICIPATION ACTIVITIES

<u>Applicant Informational Briefing</u>
In accordance with 9 VAC 5-80-1775 C of the Regulations, the applicant held an informational briefing on May 17, 2017 at the Charles City County Government Building in Charles City, Virginia.

<u>Public Hearing</u>
In accordance with 9 VAC 5-80-1775 F, a public hearing announcement was published in the *New Kent-Charles City Chronicle* newspaper on January 31, 2019. The public hearing was held on March 5, 2019. At least 10 (there were roughly 5 attendees that did not fill out the sign-in sheet) non-DEQ staff persons attended the hearing. Three of the attendees offered testimony and one written comment was received and entered into the record by the Department. Of the three oral comments provided at the hearing, one was in support of the proposed facility, one requested changes to the draft permit and one opposed the construction of the facility.

<u>Public Comment Period</u>
The comment period for the draft permit ran from January 31, 2019 through March 20, 2019. During the public comment period, 103 written comments and 3 oral comments (two participants provided both written and oral comments) were received. The written comments included one from the U.S. EPA, one from the Chickahominy Indian Tribe, one from BCP, three from environmental advocacy groups, one from the regional planning commission and 96 from citizens. The majority of the comments requested that the State Air Pollution Control Board make the final permit determination rather than DEQ.

<u>Changes to the Draft Permit</u>

1. Remove the General Electric turbine option and associated conditions
2. Remove the conditions providing for on-line (turbines in operation) water washing events
3. Add a condition (Condition #23) establishing a 96 hour per year operating limitation for turbine tuning events

4. Further clarify that the annual emission limits (Condition #36) encompass all periods of operation including startups, shutdowns and tuning events
5. Clarify the excess emission reporting requirements for startups, shutdowns and tuning events and add advance notification provisions for tuning events (Conditions #9, #10 and #51).

Lower the British thermal unit per kilowatt-hour (Btu/KWh) heat rate limits (Condition #8) and the pound of CO_2e per megawatt-hour (lb/MWh) greenhouse gas emission limits (Condition #35).

Balico, LLC/Chickahominy Power
Registration Number 52610
Prevention of Significant Deterioration Application
Summary of and Response to Public Comments

Public Notice Procedure

Before a Prevention of Significant Deterioration (PSD) permit can be issued, the draft permit must undergo 30 days of public comment, followed by a public hearing, followed by 15 more days of public comment. The Public Notice for the start of the public comment period for the draft PSD permit Chickahominy Power Station (CPS) appeared in the Charles City/New Kent Chronicle on January 31, 2019. The draft permit and engineering analysis were posted to the DEQ public notice website for review. The public comment period ran from January 31, 2019 through March 20, 2019. The public hearing was conducted on March 5, 2019.

Public Hearing

The public hearing was held at the Charles City County (Charles City County) Administration Building Auditorium, 10900 Courthouse Road, Charles City, VA. The hearing was attended by five DEQ representatives, one representative from Balico, LLC, one representative from AECOM (applicant consultant), two representatives from Charles City County government (one Board of Supervisors member, one representative from economic development), one faculty member of the University of Richmond, and 5-10 private citizens (not all of the people that attended signed the hearing attendance log). An open question and answer session preceded the formal public hearing.

Comments Received

A total of 104 comments were received, including a letter from the United Stated Environmental Protection Agency (EPA) and three oral comments presented at the public hearing. The remainder of the comments were either emails or email attachments. In the instance of a respondent submitting more than one comment during the public comment period, their comments were aggregated. DEQ has reviewed and considered all of the comments received. DEQ has grouped and summarized the comments and is providing this document to respond to the comments.

Revised Draft Permit

After consideration of each public comment and following consultation with and the concurrence of the applicant, DEQ has developed a revised draft permit that incorporates the following changes:

6. Remove the General Electric turbine option and associated conditions
7. Remove the conditions providing for on-line (turbines in operation) water washing events
8. Add a condition (Condition #23) establishing a 96 hour per year operating limitation for turbine tuning events
9. Further clarify that the annual emission limits (Condition #36) encompass all periods of operation including startups, shutdowns and tuning events
10. Clarify the excess emission reporting requirements for startups, shutdowns and tuning events and add advance notification provisions for tuning events (Conditions #9, #10 and #51).
11. Lower the British thermal unit per kilowatt-hour (Btu/KWh) heat rate limits (Condition

#8) and the pound of CO_2e per megawatt-hour (lb/MWh) greenhouse gas emission limits (Condition #35).

These revisions are discussed in more detail further in the following sections. In the remainder of this document, the draft PSD permit proposed for comment during the public comment period and public hearing will be referred to as the "draft permit" while the draft PSD permit incorporating DEQ's revisions in response to public comments and proposed for consideration by the State Air Pollution Control Board (Air Board) will be referred to as the "revised draft permit". Except for the changes noted above and the correction of minor typographical errors, the revised draft permit is substantively equivalent to the draft permit.

GENERAL COMMENTS AND ENVIRONMENTAL IMPACTS

1. General Environmental and Non-Environmental Project Impacts

Comment Summary

The majority of the comments were in opposition to the draft permit and the CPS. Where these comments were related to air quality, the majority were general in nature and did not suggest any specific improvements or short-comings in the draft permit, nor did the comments address any of the analyses contained in DEQ's engineering analysis document. These comments indicate that the CPS emissions are too high, the impact is too great, and/or no increases should be approved. The comments also indicate general opposition to the CPS and a request for denial and/or Air Board consideration of the draft permit. Some comments pertained to issues regarding station size, noise, traffic, water quality, historic resources, the greenhouse gas (GHG) impact of the natural gas industry, the financial impact on ratepayers, the necessity of or demand for the CPS and the need for renewable energy sources instead.

Response

Noise, traffic, water quality, wildlife, station necessity, impacts on historic resources and impacts on ratepayers are topics beyond the purview of the Regulations for the Control and Abatement of Air Pollution that is the authority for the draft permit.

Even though the impact on ratepayers is not a subject within DEQ's authority, it should be noted that the State Corporation Commission (SCC) does have purview over such matters, and SCC approval of the project was granted on May 8, 2018. Also, CPS is not a ratepayer financed facility; i.e. it is a merchant plant financed by private investment.

The Regulations for the Control and Abatement of Air Pollution prescribe the requirements that a source must comply with to obtain a PSD permit. In reviewing the application for this permit, DEQ performed a comprehensive regulatory review with respect to Virginia and federal air quality regulations. This includes the health-based standards promulgated by the U.S. Environmental Protection Agency (EPA) as National Ambient Air Quality Standards (NAAQS), EPA-promulgated Prevention of Significant Deterioration (PSD) increments, and Virginia's own health-based standards for toxic pollutants. DEQ's review of the initial application and subsequent updates
demonstrates that the proposed CPS will apply the Best Available Control Technology (BACT) for each applicable pollutant.

Air quality analyses were conducted in accordance with Virginia and federal permitting regulations and guidance in order to assess compliance of projected emissions from the proposed facility with all applicable NAAQS, PSD increments, and Significant Ambient Air Concentrations (SAAC). Detailed responses to comments regarding modeling and the air quality analysis are provided elsewhere in this document.

The primary NAAQS have been established in order to define air quality levels for sulfur dioxide, nitrogen dioxide, particulate matter, ozone, carbon monoxide, and lead that are protective of public health and welfare, with an adequate margin of safety. Secondary NAAQS provide public welfare protection, including protection against decreased visibility and damage to animals, crops, vegetation, and buildings. The air quality analyses demonstrated that projected air emissions from the proposed facility would neither cause nor significantly contribute to a violation of any applicable primary or secondary NAAQS.

In addition to the NAAQS, PSD increments (allowable increases in ambient concentration above a baseline level) have been established for select regulated criteria pollutants for both Class I and Class II areas. PSD increments prevent the air quality in clean areas from deteriorating to the level set by the NAAQS. The Class I area increments are much smaller than the Class II increments and are applicable in large national parks and wilderness areas. The air quality analyses demonstrated that the projected air emissions from the proposed facility would not cause or contribute to a violation of any applicable Class I or Class II area PSD increment.

In addition to the NAAQS and PSD increment modeling, an evaluation of the proposed project's effects on air quality related values (AQRVs) within neighboring Class I areas was completed. An AQRV may include visibility or a specific scenic, cultural, physical, biological, ecological, or recreational resource identified by the Federal Land Manager (FLM) for a particular area. The FLMs have an affirmative responsibility to protect the AQRVs (including visibility) of such lands, and to consider whether a proposed major emitting facility will have an adverse impact on such values. The FLMs for the applicable Class I areas located within 300 kilometers of the proposed facility indicated the proposed facility is not expected to show any significant additional impacts to AQRVs.

Additional impact analyses for the local area within Charles City County were performed to assess the impacts from the proposed facility on visibility, vegetation and soils, and the potential for and impact of secondary growth. Visibility in the immediate vicinity of the proposed facility will be protected by air pollution control requirements and stringent visible emission limits included in the air permit. An analysis of the impacts from the proposed facility on soils and vegetation did not identify any adverse impacts. Furthermore, no new significant emissions from secondary growth during the construction and operation phases of the proposed facility are anticipated.

Acrolein, beryllium, cadmium, chromium, formaldehyde, lead, mercury, and nickel emissions were demonstrated to be in compliance with the SAAC guidelines in Virginia's air toxic pollutant regulation, 9 VAC 5 Chapter 60, Article 5 (Emission Standards for Toxic Pollutants from New and Modified Sources) of Virginia's Regulations for the Control and

Abatement of Air Pollution. These standards are designed to be protective of human health and the environment.

Many comments suggested that the air quality analyses performed are only for "regional" standards and are not indicative of the impacts that will be experienced by local residents. This perception is not accurate. Modeling was conducted for the area surrounding the plant in Charles City County using the peak emission rates to demonstrate compliance with the standards.

In summary, the draft permit requirements are designed to ensure protection of public health and the environment in accordance with the state and federal ambient air quality standards and regulations. More detail regarding the subject matter of many of these comments is addressed later in this document in responses to comments that were specific to the draft permit.

2. General Environmental Justice Concerns

<u>Comment Summary</u>

Many of the comments described above raised environmental justice (EJ) as an issue of concern. They stated that Charles City County has a significant population of minorities (African American and Native American) and low income families. Many comments feared that the emissions from the proposed facility would have a disproportionate effect on the minority community. However, the majority of such comments were not specific about the nature of any alleged adverse or disproportionate impacts or the identification of specific impacted communities (other than general references to Charles City County as a whole (i.e. high % population of Native Americans and references to the county as "minority majority")). In general, the comments also did not address the EJ analysis included in DEQ's engineering analysis document. Examples of such comments include such statements as "Issues around environmental justice…need to be addressed" and "I'm concerned because the county is a minority majority county…".

<u>Response</u>

The federal Clean Air Act, the National Ambient Air Quality Standards, the State Air Pollution Control Law and the State Air Pollution Control regulations were established and designed to protect the health and environment for all people; i.e. the NAAQS apply equally to all stationary sources regardless of any site-specific demographic factors. The draft permit for the CPS will ensure compliance with these air quality laws, standards and regulations to protect the health and environment for all residents of Charles City County and throughout the Commonwealth.

Some comments relied on or referenced EPA definitions, data and/or policies on EJ. For example, Environmental Justice is defined by the EPA as the fair treatment and meaningful involvement of all people regardless of race, color, faith, national origin, or income, in the development, implementation, and enforcement of environmental laws, regulations, and policies. Executive Order 29 (issued by Governor Northam on January 22, 2019) uses the same definition and established the Virginia Council on Environmental Justice (VCEJ). EPA further considers that <u>fair treatment</u> means no group of people should bear a disproportionate share of the negative environmental consequences resulting from industrial, governmental and commercial operations or policies.

Regarding "…disproportionate...negative…consequences", EPA's Environmental Appeals Board has previously determined (*see Energy Answers Arecibo, LLC 2014*) that:

> "The Board generally "relies on and defers to the Agency's cumulative expertise" where the permit issuer's environmental justice determinations are based on a proposed facility's compliance with the relevant NAAQS. *See Shell 2010* 15 E.A.D. at 156 (explaining that, "[i]n the context of an environmental justice analysis, compliance with the NAAQS is emblematic of achieving a level of public health protection that, based on the level of protection afforded by a primary NAAQS, demonstrates that minority or low-income populations will not experience disproportionately high and adverse human health or environmental effects due to exposure to relevant criteria pollutants"); *see also In re MHA Nation Clean Fuels Refinery*, 15 E.A.D. 648, 669 n.59 (EAB 2012). NAAQS are designed to protect public health with an adequate margin of safety, including sensitive populations such as children, the elderly, and asthmatics. *See In re AES Puerto Rico*, LP, 8 E.A.D. 324, 351 (EAB 1999), *aff'd sub nom. Sur Contra La Contaminación v. EPA*, 202 F.3d 443 (1st Cir. 2000); *see also Shell 2010*, 15 E.A.D. at 149 n.72."

As indicated in DEQ's engineering analysis and the responses to other comments in this document, DEQ has performed an extensive review of this project in accordance with Virginia's air quality laws and regulations. DEQ found that if the facility is constructed and operated in accordance with the conditions of the draft permit, it will comply with all applicable air quality regulations. The air quality analysis is conservative and demonstrates emissions from the facility will not approach any of the applicable ambient air quality standards as permitted. Therefore, the air permit process used by DEQ and the requirements contained in the resulting draft permit ensure no disproportionately high or adverse air quality impact on any resident of Virginia. None of the comments submitted provided information to the contrary.

Efforts to meaningfully involve Charles City County residents started with the applicant advertising and hosting a public information session in Charles City, Virginia on May 17, 2017. These efforts further included the public notice of the draft permit, the public comment period and the public hearing (held on March 5, 2019) as published in the Charles City/New Kent Chronicle on January 31, 2019. This publication is widely distributed throughout the area. Additionally, DEQ posted the public notice, the draft permit, and the draft engineering analysis on its website. On January 31, 2019, specific notices were also sent to the Pamunkey, Mattaponi, Chickahominy and Eastern Chickahominy Indian Tribes via email and/or the U.S. Postal Service. Furthermore, senior DEQ staff contacted the same Tribes and organized and participated in a face to face meeting with interested parties (including Chief Adkins of the Chickahominy Indian Tribe) at the Chickahominy Tribal Council Building in Charles City County on February 28, 2019. On March 14, 2019, Chief Stephen Adkins sent an email to DEQ Director, David Paylor. The Chief's email states that the Chickahominy Indian Tribe does not oppose the name for the CPS and that the Chickahominy Indian Tribe objects to being used as a reason to designate the CPS permit for review by the Air Board. DEQ did not receive any indication from any other Indian Tribe indicating opposition to the CPS.

With respect to applicant actions regarding community engagement, as described in the March 14, 2019 email from Chickahominy Indian Tribe Chief Ralph Adkins to DEQ Director Dave Paylor:

- Mr. Irfan Ali (Managing Partner Chickahominy Power) contacted Chief Adkins at the outset of the project's development and asked if the Chickahominy Indian Tribe had any concerns regarding the proposed name of the power plant. The Chickahominy Indian Tribe did not oppose the name for the power plant.
- On March 1, 2019, The Chickahominy Indian Tribe held a public meeting to discuss the CPS with around 40 people in attendance. Mr. Ali answered public questions for approximately 1.5 hours. After the public meeting, Mr. Ali fully answered further questions during a private meeting with the Chickahominy Indian Tribe Tribal Council.

Also, as described in the March 12, 2019 letter from Balico, LLC to DEQ:

- Mr. Ali attended a summer 2016 Shirley Plantation event to raise awareness of and answer questions regarding the CPS.
- Mr. Ali attended an August 2016 executive meeting of the Charles City County Board of Supervisors to answer questions and provide an update regarding the CPS.
- Beginning in late 2016, Mr. Ali attended a series of meetings with Mr. Bruce Howard (Charles City County resident and adjacent (to CPS) business owner) and other Charles City County business owners.

As indicated in the draft engineering analysis, DEQ also used EJSCREEN to evaluate the area of Charles City County surrounding the proposed CPS. EJSCREEN is an on-line EPA-maintained screening tool used to estimate the demographics of a particular radius around a site, using recent census data, and cross-reference the demographics with current ambient air quality. As a tool, it does not evaluate any air quality impact of the proposed facility on the population. The air quality analysis discussed elsewhere in this document is used to determine the air quality impact around the plant.

DEQ generated EJSCREEN reports for 1-mile, 2-mile and 5-mile rings around the CPS location. These areas represent the greatest expected air quality impacts from the facility. The demographic data from these reports is summarized below:

CPS EJSCREEN Report Summary

Report Area	1-Mile	2-Mile	5-Mile	Virginia Average
Minority Population	42%	45%	34%	37%
Minority Population % over Virginia Average	14%	22%	N/A (negative value)	N/A
Low Income Population	23%	25%	20%	27%

Report Area	1-Mile	2-Mile	5-Mile	Virginia Average
Overall Demographic Index	33%	35%	27%	32%

All low income population values are below the average for the Commonwealth of Virginia, and all of the minority population values are below the average (52.8%) for Charles City County as a whole[1].

To the extent that Charles City County as a whole is considered as an EJ community, as suggested by some comments, Charles City County representatives did provide DEQ with a certification that the proposed CPS would comply with all applicable local ordinance and zoning requirements. Charles City County's Board of Supervisors (representing the majority minority population as a whole) also unanimously approved a special use permit (and subsequent revisions) for the CPS on at least four occasions: May 28, 2015, September 27, 2016, October 25, 2016 and November 22, 2016.

3. General Climate/GHG Comments

Comment Summary

Many of the comments raised climate change and greenhouse gas emission concerns. The majority of the comments were general in nature and did not suggest any specific improvements or short-comings in the draft permit, nor did the comments address the GHG BACT analysis contained in DEQ's engineering analysis document. Some of the comments also stated that DEQ's proposed carbon trading rule, Governor Terence McAuliffe's Executive Directive 11 (2017) and/or Virginia's participation in the United States Climate Alliance prohibits the permitting of the CPS or that the construction of the CPS would be contrary to these same rules/programs. These comments state that the CPS GHG emissions are too high, should be replaced by renewable energy and/or no fossil fuel fired power facilities should be approved. Some comments also stated that the Air Board must consider climate impacts in an evaluation of site suitability.

Response

In accordance with the U.S. Supreme Court's 2014 decision in UARG v. EPA, DEQ's authority to regulate GHG emissions from any facility under the PSD permitting program is limited by law and regulation to determining and applying BACT. In determining BACT, including for GHG, for a PSD permit, DEQ analyzes the engineering design of the facility as proposed. This is because DEQ/EPA have long recognized as a central tenant of the air pollution permitting program that permitting authorities do not have the ability to redesign the basic business purpose of a facility. Therefore, as a general matter and in this specific case, DEQ does not require the substitution of renewable energy generation for fossil-fuel energy generation. It is noted that the facility, as permitted, is designed to operate continuously (8760 hours/year) whereas power from renewable energy sources (such as solar) are generally not continuously available. DEQ's evaluation is also limited to the emissions from the proposed facility as opposed to the emissions

[1] https://www.census.gov/quickfacts/charlescitycountyvirginia

from part or all of the natural gas supply chain, natural gas pipelines, the natural gas industry as a whole, fracked natural gas or any other source of emissions outside the facility boundary. It should be noted that this position was confirmed by a recent court[2] decision regarding a similar determination for the Greensville Power Station. However, DEQ is taking steps to address GHG emissions from the natural gas industry (pipelines, compressor stations, etc.) via other regulatory mechanisms. This includes the recently established methane workgroup to develop recommendations for addressing emissions from natural gas infrastructure as well as other programs described in Appendix A of this document.

In particular, the Virginia Carbon Trading Rule (VCTR; a potential link to the multi-state Regional Greenhouse Gas Initiative) establishes a carbon emission cap and trade program for the fossil fuel fired electric generating unit source category. The State Air Pollution Control Board voted 5-2 to approve the final regulation on April 19, 2019[3]. Although the GHG emissions from the CPS would be subject to this rule and the associated GHG emission cap, nothing in the proposed rule prohibits the permitting or construction of new fossil-fuel fired electric generating units in general or the CPS in particular. The same is true for Executive Order 11 and Virginia's participation in U.S. Climate Alliance. In fact, the final carbon trading rule specifically includes provisions addressing the inclusion of new GHG-emitting electric generating units without increasing the GHG emission cap. In general, when new, more efficient EGU facilities are constructed (such as natural gas fired combined cycle plants), these more efficient units displace the operation of older, less efficient and more costly units.[4] The adoption of VCTR should only reinforce this natural market-based tendency.

Specific comments on DEQ's GHG BACT are addressed later in this document (Comment #18).

4. General Health-Related Comments

<u>Comment Summary</u>
Several comments expressed general concern about the overall adverse impacts of pollution on human health. A few comments stated that the Virginia Department of Health indicates that, relative to other areas of Virginia, Charles City County and the surrounding region show a higher incidence than normal of asthma and chronic obstructive pulmonary disease (COPD). A few comments also referenced the proximity of the proposed facility to their residence and their concern that the plant's emissions would adversely affect health.

<u>Response</u>
The Federal Clean Air Act requires that EPA establish and update National Ambient Air

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[2] Circuit Court for the City of Richmond: *The Virginia Chapter of the Sierra Club v. The Virginia State Air Pollution Control Board (2017)*
[3] From the 2019 Acts of Assembly: <u>Item 4-5.11 LIMITATIONS ON USE OF STATE FUNDING</u>
"Notwithstanding any other provision of the Code of Virginia, no expenditures from the general, special, or other nongeneral fund sources from any appropriation by the General Assembly shall be used to support membership or participation in the Regional Greenhouse Gas Initiative (RGGI) until such time as the General Assembly has approved such membership as evidenced by language authorizing such action in the Appropriation Act, with the exception of any expenditures required pursuant to any contract signed prior to the passage of this act by the General Assembly, nor shall any RGGI auction proceeds be used to supplement any appropriation in this act without express General Assembly approval."
[4] https://www.eia.gov/todayinenergy/detail.php?id=25652

Quality Standards (NAAQS) designed to protect human health and welfare. DEQ developed the draft permit for the CPS to ensure compliance with these health-based standards. Therefore, within the context of air quality laws and regulations, risk was evaluated by requiring the applicant to demonstrate compliance with both acute (short-term) and chronic (annual) air quality standards. For example, the NAAQS are based on air quality criteria, which are established to accurately reflect the latest scientific knowledge useful in indicating the nature and extent of identifiable effects on public health or welfare that may be expected from the presence of the pollutant in ambient air. The EPA Administrator promulgates and periodically reviews, at five-year intervals, primary (health-based) and secondary (welfare-based) NAAQS for such pollutants. Based on periodic reviews of the air quality criteria and standards, the Administrator can make revisions in the criteria and standards and promulgate any new standards as may be appropriate. The Clean Air Act also requires that an independent scientific review committee advise the EPA Administrator as part of this NAAQS review process, a function performed by the Clean Air Scientific Advisory Committee (CASAC).

Key components of the NAAQS review are the Integrated Science Assessment (ISA) and the Risk/Exposure Assessment (REA). The ISA is a comprehensive review, synthesis, and evaluation of the most policy-relevant science, including key science judgments that are important to inform the development of the risk and exposure assessments, as well as other aspects of the NAAQS review. The REA draws upon information and conclusions presented in the ISA to develop quantitative characterizations of exposures and associated risks to human health or the environment associated with recent air quality conditions and with air quality estimated to just meet the current or alternative standard(s) under consideration. This assessment includes a characterization of the uncertainties associated with such estimates.

Toxic pollutants were also evaluated as part of this permitting process. Emissions estimates of federal hazardous air pollutants (HAPs) known to result from the power station operations were provided as part of the permit application. Several of these HAPs, acrolein, beryllium, cadmium, chromium, formaldehyde, lead, mercury, and nickel, exceeded the exemption rates contained in 9VAC5-60-300, requiring BACT and an air quality analysis under Virginia's toxics rule. The Virginia air toxic pollutant regulation establishes a health-based ambient air standard for each pollutant and is intended to protect the health of the most susceptible person on both an hourly (acute) and annual (chronic) basis. The air quality analysis for the CPS demonstrates compliance with the applicable Significant Ambient Air Concentrations (SAACs).

As indicated above and in response to other comments, modeling conducted for this proposed facility predicted maximum concentrations of pollutants to which an individual might be exposed. When the predicted concentrations were compared to the individual pollutant standards, compliance was shown in each case.

See also DEQ's response to comments concerning the CPS's potential contribution to ambient ozone concentrations (Comment #5).

5. General Ozone Comments

Comment Summary

A few comments stated concerns about the impact on regional air quality and, in particular, ozone. Comments referenced the American Lung Association grading system and the fact that it gave Charles City County a "C" grade for ground-level ozone. Comments expressed concern about the combined ozone impacts of the proposed Chickahominy facility and the C4GT facility. Comments questioned the reliance on the Shirley Plantation ozone monitoring station. Specifically, comments questioned whether ozone levels in directly impacted communities closer to the proposed Chickahominy and C4GT facilities would comply with the 8-hour ozone NAAQS if both facilities were in operation.

Response

DEQ evaluated ozone impacts in accordance with EPA's Guideline on Air Quality Models (40 CFR Part 51, Appendix W). The Guideline outlines a multi-tiered approach for single source permit assessments. The tiered approach is primarily designed for major sources of air pollution subject to Prevention of Significant Deterioration (PSD) permitting.

Consistent with the January 2017 EPA document "Guidance on the Use of Models for Assessing the Impacts of Emissions from Single Sources on the Secondarily Formed Pollutants: Ozone and $PM_{2.5}$", the ozone impacts were calculated using the following information:

(1) existing ozone modeling data,
(2) the relationship of the modeled precursor emissions and resultant ozone concentrations of that model, and
(3) the proposed project's precursor emissions.

Ozone concentrations were estimated for both turbine options. The draft permit contained limits for both the General Electric (GE) and Mitsubishi (MI) turbines. However, the revised draft permit removes the conditions related to the GE turbine since the applicant has selected the MI turbine option. The calculation of ozone impacts also accounted for the C4GT project, which has not been constructed and is not reflected in the existing ambient monitoring data at the Shirley Plantation. These results are presented in the table below.

Contributions to Ozone from Individual Precursor Emissions

Facility and Turbine Option	Averaging Period	NO_X Contribution (ppb)	VOC Contribution (ppb)	Total Ozone Modeled Concentration (ppb)
Chickahominy - GE	8-hour	1.48	0.01	1.49
Chickahominy - MI	8-hour	1.64	0.03	1.67
C4GT	8-hour	1.19	0.02	1.21
Total GE Option with C4GT				**2.69**
Total MI Option with C4GT				**2.87**

The current monitored ozone design value for the area is 63 parts per billion (ppb) (2016-2018). The addition of the CPS's worst-case daily impact, combined with C4GT's impact, will remain below the 8-hour ozone NAAQS of 70 ppb (worst case is 65.87 ppb). Furthermore, using this calculation methodology is conservative on the basis that it sums a daily maximum 8-hour ozone modeled concentration to a design value. The proposed facility's actual impact on the design value (fourth highest ozone concentration averaged over 3 years) will be less than this calculation based on DEQ's ozone modeling experience.

In addition, recent modeling conducted by the Ozone Transport Commission (OTC) projects continued improvements in ozone concentrations for Charles City County. The modeling results below do not include the specific impacts from the Chickahominy and C4GT projects but do include generic growth and control estimates for all source sectors, including the power sector. Power sector model inputs are obtained from the Eastern Regional Technical Advisory Committee (ERTAC) forecasting tool.[5]

Future Projected Ozone Design Values for Charles City County

2020	2023	2028
61.2 ppb	59.7 ppb	58.8 ppb

Comments referenced the American Lung Association (ALA) grade "C" for Charles City County. As an initial matter, the most recent ALA grades for Charles City County are an "A" for "particle pollution" and a "B" for ozone[6]. The ALA's grading system differs significantly from the methodology EPA uses to determine violations of the ozone NAAQS. DEQ and EPA determine whether a jurisdiction violates the standard based on the fourth maximum daily 8-hour ozone reading each year averaged over three years. By contrast, the ALA system is based on a weighted average for each jurisdiction. Specifically, this system assigns weighting factors for each category of the Air Quality Index (AQI) and evaluates the number of days in each category over the entire 3-year period.

Both DEQ and EPA implement the regulatory form of the ozone NAAQS which has undergone public comment and is endorsed by the Clean Air Science Advisory Committee (CASAC). EPA describes its rationale for the standard, including the form of the standard (i.e. fourth highest averaged over 3 years), in its "Integrated Review Plan for the Review of the Ozone National Ambient Air Quality Standards External Review" (EPA-452/P-18-001, October 2018).

Finally, it is important to note that both the Chickahominy and C4GT power stations would be subject to the Cross State Air Pollution Rule (CSAPR) (40 CFR 97), if constructed. The EPA promulgated the CSAPR to replace the Clean Air Interstate Rule (CAIR) and is designed to significantly improve air quality by reducing power plant emissions contributing to ozone and/or fine particle pollution. The CSAPR requires fossil fuel-fired electric generating units at coal-, gas-, and oil-fired facilities in 27 states to reduce emissions to help downwind areas attain fine particle and/or ozone NAAQS. Application of the CSAPR ensures that Virginia will continue to meet all requirements of § 110(a)(2)(D)(I)(i).

EPA sets a pollution limit (emission budget) for each of the states covered by the CSAPR. Authorizations to emit pollution, known as allowances, are allocated to affected sources based on these state emissions budgets. The rule provides flexibility to affected sources, allowing sources in each state to determine their own compliance path. This includes adding or operating control

[5] https://www.marama.org/2013-ertac-egu-forecasting-tool-documentation
[6] https://www.lung.org/our-initiatives/healthy-air/sota/city-rankings/states/virginia/charles-city.html

technologies, upgrading or improving controls, switching fuels, and using allowances. Sources can buy and sell allowances and bank (save) allowances for future use as long as each source holds enough allowances to account for its emissions by the end of the compliance period.

New units such as those proposed at Chickahominy and C4GT are subject to the CSAPR but did not receive allowance allocations as existing units. However, these units are eligible for a new unit set aside (NUSA) allowance allocation. NUSA allowance allocations are a batch of emissions allowances that are reserved for new units that are regulated by the CSAPR, but were not included in the final rule allocations. The NUSA allowance allocations are removed from the original pool of regional allowances and divided up amongst the new units, so as not to exceed the emissions cap set in the CSAPR.

Aside from the NUSA, these facilities must comply with the permitting, monitoring, recordkeeping, and reporting requirements set forth by the CSAPR, including the installation and certification of a continuous emission monitors.

6. General Shirley Plantation/Background Ambient Monitoring Data Comments

Comment Summary

Comments expressed concerns about the lack of site-specific monitoring data and the use of the Shirley Plantation monitor. One comment stated that the Shirley Plantation site is located in the opposite direction from prevailing winds relative to the Chickahominy Power Station.

Response

Cumulative NAAQS modeling requires the use of background concentrations from ambient monitoring data. These data are combined with the modeled impact from the proposed facility and other nearby sources to determine the total air quality impact. Background air quality represents contributions from natural sources, other unidentified sources near the project that are not explicitly modeled, and regional transport contributions from more distant sources (domestic and international).

A conservative aspect of this particular modeling analysis is that it incorporates nearby monitoring data collected at Shirley Plantation (approximately 8.5 miles southwest of the proposed facility and within Charles City County) to represent background air quality. These data are added to the total impact, in addition to explicitly modeling nearby sources that affect this monitoring site. As a result, the air quality impacts are often overestimated or “double-counted” as it is commonly called.

The monitor is located upwind of the facility rather than downwind of the facility as stated by one comment. The prevailing wind direction for Charles City County is from the south-southwest, which is an ideal direction for the monitor to capture transported pollution from the nearby industrialized urban area of Hopewell City.

DEQ uses its existing statewide monitoring network to develop background ambient air concentrations for modeling. These data conform to the same quality assurance and other requirements as those networks established for Prevention of Significant Deterioration (PSD) permitting purposes. Accordingly, the air quality monitoring data has sufficient completeness and undergoes appropriate data validation procedures.

Finally, the PSD regulations require that a PSD permit application contain an analysis of existing air quality for all regulated pollutants that the source has the potential to emit in significant amounts. The definition of existing air quality can be satisfied by air measurements from either a state-operated or private network, or by a pre-construction monitoring program that is specifically designed to collect data in the vicinity of the proposed source. To fulfill the pre-construction monitoring requirement for PSD without conducting on-site monitoring, a source may justify that data collected from existing monitoring sites are conservatively representative of the air quality near the proposed Project site. DEQ considers the background air quality used in this analysis to be both appropriate and conservatively representative of existing air quality in the area surrounding the proposed facility. Monitoring sites, in part, are selected based on the review of EPA-recommended criteria such as emissions data and population density. The Shirley Plantation monitor is immediately downwind of Hopewell City and is greatly influenced by its emissions. As a result, concentrations at this monitor, for establishing existing background air quality, are greater than the actual project site.

<u>EPA COMMENTS AND RESPONSES</u>

7. AERSURFACE Analysis- Meteorological site land use characteristics

<u>Comment Summary</u>
EPA requested a comparison of site characteristics between the Richmond Airport and the site of the proposed facility to ensure similarity between the two sites. EPA asked if snow cover was evaluated to ensure that continuous (monthly) snow cover was not present during the five (5) year simulation period (2012-16). EPA also questioned if land use/land cover remained relatively unchanged in the area of the proposed facility since 1992, the date of the land use files used in EPA's modeling tool.

<u>Response</u>
To verify representativeness of the airport land use, AERSURFACE was applied for a single 1 kilometer (km) sector around the Richmond Airport and proposed Chickahominy Combined-Cycle Power Plant using average moisture conditions and seasonal classifications as follows:

Jan, Feb, Dec = Late autumn after frost and harvest, or winter with no snow
Mar, Apr = Transitional spring (partial green coverage, short annuals)
May, Jun, Jul, Aug, Sep = Midsummer with lush vegetation
Oct, Nov = Autumn with unharvested cropland

Results of the two AERSURFACE runs are presented in the table below. The results show that the albedo and Bowen ratio are very similar between the airport and Project site. The surface roughness is different however. Use of a lower surface roughness tends to give high modeled concentrations as the modeled plume is subject to less turbulence. Based on this analysis, the Richmond Airport can be considered representative of the Project site with respect to land use.

The analysis did consider snow cover and found that there were no months in the five years modeled (2012-2016) that had continuous snow cover on the ground for more than half the month. All months/years were considered to have no snow cover.

The land use surrounding the Richmond Airport (especially within 1 km of the anemometer) and Project site has not changed dramatically in 25 years. This would make the 1992 NLCD data used to run AERMET still reasonably representative of the area(s).

AERSURFACE Land use Comparison

Site	**Annual Average Land Use**		
	Albedo	**Bowen**	**Z_0**
Richmond Airport	0.16	0.71	0.069
Chickahominy	0.15	0.49	0.190

8. Background Air Quality and Pre-Construction Monitoring

Comment Summary

EPA asked DEQ to provide the most recent PM-2.5 and ozone design values to ensure there have been no significant changes in those concentrations that could change the outcome of the NAAQS modeling analysis.

EPA also asked if the monitor values used in the analysis were "deemed complete" when the data were collected.

Response

Updated ambient air quality data was reviewed for the most recent time period available in DEQ's annual air monitoring summary reports for 2015-2017. Table 6-15 from the PSD application was updated below to include the more recent ambient monitoring data. Comparison of the 2014-2016 data with the 2015-2017 data shows that the more recent data is equal to or lower than that used in the air quality modeling analysis for PM-2.5 and ozone. There are no issues with data capture/quality for the stations utilized below.

Monitored Background Concentrations

Pollutant	**Averaging Period**	**Concentration**		**Units**	**Location (AQS ID)**	**State**
		2014-2016[7]	2015-2017[8]			
PM-10	24-hour	23	23	µg/m3	Woodson Middle School (51-670-0010)	VA

7 http://www.deq.virginia.gov/Portals/0/DEQ/Air/AirMonitoring/Annual_Report_2016.pdf

8 https://www.deq.virginia.gov/Portals/0/DEQ/Air/AirMonitoring/2017_Virginia_Ambient_Air_Monitoring_Report_ADA_Compliant.docx

Pollutant	Averaging Period	Concentration		Units	Location (AQS ID)	State
PM-2.5	24-hour	16	14.7	µg/m³	Shirley Plantation (51-036-0002)	VA
PM-2.5	Annual	7.3	7.0	µg/m³	Shirley Plantation (51-036-0002)	VA
NO_2	1-hour	42	38	ppb	Shirley Plantation (51-036-0002)	VA
NO_2	Annual	5	4	ppb	Shirley Plantation (51-036-0002)	VA
CO	1-hour	1.5	1.5	ppm	Math & Science Center (51-087-0014)	VA
CO	8-hour	1.2	1.2	ppm	Math & Science Center (51-087-0014)	VA
SO_2	1-hour	27	24	ppb	Shirley Plantation (51-036-0002)	VA
SO_2	3-hour	33.6	33.6	ppb	Shirley Plantation (51-036-0002)	VA
SO_2	24-hour	6.2	6.2	ppb	Shirley Plantation (51-036-0002)	VA
SO_2	Annual	0.5	0.5	ppb	Shirley Plantation (51-036-0002)	VA
Ozone	8-hour	63 (2014-2016)	63 (2016-2018)	ppb	Shirley Plantation (51-036-0002)	VA

9. Secondary PM2.5 and Ozone - Approach

<u>Comment Summary</u>
EPA commented that the proposed facility's projected secondary PM-2.5 concentrations would represent concentrations in the immediate area of the CPS.

<u>Response</u>
DEQ concurs with EPA. The approach used to estimate secondary PM-2.5 from the project is based on the use of EPA photochemical grid modeling and their guidance on how to perform a Tier 1 screening analysis for secondary formation. This Tier 1 approach is designed to be conservative on multiple levels.

10. Modeling Approach

<u>Comment Summary</u>
EPA questioned whether the background source emissions included in the cumulative analyses represent maximum allowable/permitted hourly emission rates or if they represent actual hourly emission rates. EPA further commented that Section 8.2.2 (c) of EPA's Appendix W Guideline on Air Quality Models allows the applicant to use emission rates for nearby sources included in any cumulative analysis that reflect actual operations instead of a permitted and/or maximum allowable emission rate.

Response
The emission rates for nearby background sources included in the cumulative NAAQS and PSD increment analyses represent each facility's actual operating level as opposed to permitted and/or maximum allowable emission rates. The development of the inventory is consistent with current Appendix W modeling guidance.

11. Summary of NAAQS Analysis

Comment Summary
EPA commented that it concurred with DEQ regarding the 1-hr NO2 simulations and the fact that emissions from the emergency generator or the emergency fire pump are not included.

EPA also commented on the peak modeled 1-hour NO2 concentrations for the GE units and that they are almost 96% of the NAAQS during simulated cold start periods. EPA suggested that the applicant refrain from testing its emergency generator during cold startups because it could potentially contribute to exceedances of the 1-hour NO2 NAAQS.

Response
It is extremely unlikely that all three (3) combustion turbines will be cold started at the same time (which is how they were modeled) along with testing of the emergency generator under the meteorological conditions that were associated with the peak modeled NO_2 concentrations from the model. It is even more unlikely that this would happen more than the 7 times per year for three consecutive years as that is what it would take to cause a potential NAAQS violation. Therefore, DEQ does not agree that an additional permit condition is necessary to address this scenario.
It is important to note that the draft permit contained limits for both the GE and MI turbines. However, the revised draft permit removes the conditions related to the GE turbine since the applicant has selected the MI turbine option. The margin of compliance with the 1-hour NO_2 NAAQS for the MI turbine option is larger (28% instead of 4%) which further supports the position that a permit condition is not needed to address this unlikely scenario.

12. Summary of PSD Increment Consumption Analysis

Comment Summary
EPA questioned whether the modeling analysis included off-site source shutdown emissions, which would expand PM-10 and annual NO_2 increment consumption and (conservatively) bias the final model results.

EPA also requested clarification on whether this application triggered the PSD baseline PM-2.5 dates for Charles City County or any other surrounding counties in Virginia.

Response
The PSD increment analysis did not consider any increment expansion making the analysis conservative. DEQ appreciates EPA acknowledging the conservative aspects of the modeling analysis. This application did not trigger the PM-2.5 minor source baseline date for Charles City County or any other surrounding counties in Virginia. The PM-2.5 baseline date was previously

triggered in Charlies City County by another recently permitted PSD source, C4GT.

13. Ozone NAAQS Analysis Results

Comment Summary

EPA commented that the analysis used to estimate the proposed plant's (worst-case) impacts on ozone reflects local impacts since the underlying photochemical model used an approximately 12-km grid cell spacing.

Response

DEQ concurs with EPA. The approach used to estimate ozone from the project is based on use of EPA photochemical grid modeling and their guidance on how to perform a Tier 1 screening analysis for ozone. This Tier 1 approach is designed to be conservative on multiple levels and is further discussed under the Ozone Impacts section of this document.

14. Class I Area Analysis

Comment Summary

EPA acknowledged that the secondary PM-2.5 impacts used for the distant Class I areas are conservative (i.e. overestimated) because they are generally representative of values closer to the proposed source.

EPA also observed that the Class I area analysis did not account for the substantial increment expansion created by (NOX and SO2) control installations and shut downs at regional coal-fired power plants and that this could have been included if a cumulative analysis was triggered.

Response

DEQ agrees that the modeling approach most assuredly overestimates secondary PM-2.5 formation at the Class I area, adding to the conservatism of the analysis.

DEQ also concurs with EPA that the modeling did not trigger a cumulative PM-2.5 PSD increment analysis and, therefore, increment expansion that has occurred related to SO_2 and NO_X reductions was not considered. DEQ agrees that there has been significant PSD increment expansion, which is largely the result of the conversion from coal to natural gas in recent years. DEQ encourages EPA to determine an appropriate methodology to account for increment expansion. DEQ also recommends that increment expansion be evaluated using existing monitoring data as opposed to modeling shutdown facilities with negative emission rates. The modeling approach using negative emission rates for shutdown sources has a multitude of issues and should be avoided.

15. Alternate Operating Scenario Emission Accounting

Comment Summary

EPA suggests a revision to draft permit Condition #36 to explicitly state that emissions from alternate operating scenarios are included in the annual totals for the turbines.

Response

The emission limits in Condition #36 of the draft permit do include emissions from alternative operating scenarios. The revised draft permit version of this condition has been revised to further clarify this intent.

SIERRA CLUB COMMENTS AND RESPONSES

16. Tuning and Water Wash BACT

Comment Summary

Alternative emission limits for maintenance activities (tuning and on-line water washing) are not justified as BACT. If such limits are justified, DEQ should limit their duration and frequency. Similar sources do not have such limits in their permit. The source did not request alternative limits for PM, yet DEQ gave them such in the draft permit. The applicant described three different types of tuning, yet those are not included in the draft permit. The draft permit fails to require advance notification of tuning and water-washing, and the recordkeeping and reporting requirements are inadequate.

Response

Recently-issued permits in Virginia, including the Green Energy Partners/Stonewall plant, the Dominion Greensville Power Station and the C4GT Power Station have alternative numeric emission limits or work practice requirements, distinct from the "normal" operations emission limits, for maintenance activities. Since BACT limits must be achievable at all times including worst-case conditions, alternative emission limits have been justified during certain maintenance activities because these activities alter the normal operating conditions of the turbines sufficiently to impact their emission profile. The requirements in these permits are meant to restrict and minimize the duration of these activities and otherwise implement BACT for such events.

Section 5.3.4.4 of the permit application from Chickahominy Power requested limitations on the duration of each event to restrict PM emissions from maintenance activities.

The events themselves are limited in duration, which limits the short-term emissions from those events. The emissions from these activities represent the worst-case total from such an event over the averaging time allowed by the permit. Therefore, the limitation would be for the worst-case tuning event since other tuning events would not last as long and would have less emissions. On an annual basis, DEQ determined that the emissions from these activities would not differ from normal operation, i.e. a limit of 214 lb/turbine/day x 365 days is the same as 8.9 lb/hr x 8760 hr/year. However, after considering the comment, DEQ has added an annual limit of 96 hours of tuning per turbine per year to ensure that the exemption from normal short-term emission limits from tuning events will be limited on an annual basis. Also, DEQ has also removed the on-line water washing exemption from the normal short-term emission limits.

DEQ agrees that an advance notification for each tuning event would add value to the existing compliance mechanisms of the draft permit and has therefore amended Condition #10 of the revised draft permit to include such a provision. DEQ believes that the advance notice provision, in conjunction with requiring the facility to keep records of each tuning event, the duration of each event, and the emissions from each event for NOx and CO (via the use of continuous emission monitoring systems), represents a comprehensive compliance mechanism for tuning events. These records are subject to on-going inspection by DEQ to ensure compliance with the requirements of the permit.

17. Startup and Shutdown (SU/SD) Events

Comment Summary

Emissions from startup and shutdown (SU/SD) were based on vendor data, however that vendor data was not included in the permit application. The draft permit does not contain annual limitations for the number of annual SU/SD events. The draft permit does not include reporting of SU/SD.

Response

DEQ disagrees that the permit record is insufficient to justify the proposed permit's treatment of SU/SD events. The applicant has certified the SU/SD emission data contained in the application, and this data is consistent with data from other combined cycle power plants.

The short-term emission limits for SU/SD, along with minimizing event duration and maximizing control equipment operation to the extent possible, represent BACT for the worst-case operating conditions expected during such events. The proposed annual emission limits for the turbines are based on a worst-case estimate of the frequency of such events in the course of a year and function as limits on the occurrence of such events. Given that the proposed facility is configured as a combined-cycle plant, the expected SU/SD frequency would be much less as the facility is highly incentivized to maximize normal operations. Since the annual emissions represent the worst-case emissions from all the possible operation of the turbines, then annual restrictions on the number of SU/SD events is not necessary.

DEQ disagrees that reporting is valuable for SU/SD events. DEQ believes that requiring the facility to keep records of each SU/SD event, the duration of each event, and the emissions from each event for NOx and CO (via continuous emission monitoring systems) is a sufficient compliance mechanism. These records are subject to on-going inspection by DEQ to ensure compliance with the requirements of the permit. DEQ has revised the text of the conditions addressing SU/SD and tuning events (Conditions #9, #10 and #51 of the revised draft permit) in order to provide increased consistency and clarity to the excess emission reporting requirements.

18. Greenhouse Gas (GHG) BACT

Comment Summary

The lb/MWh net and Btu/kWh limits on the turbines is the same for each turbine vendor. BACT for greenhouse gasses should be the "absence of duct burning." The draft permit should also have a lb CO_2e/MWh gross limit that reflects total amount of emissions due to operation of the power plant, not just operation of power to the grid. An appropriately stringent limit on pounds of CO2-e per gross MWh would encourage Chickahominy Power to limit the parasitic load and would promote overall improvements in efficiency. The Dominion Greensville plant had a lower heat rate limit so Chickahominy's heat rate limit should be at least that stringent. Dominion had a lower lb/MWh CO_2e limit so the CPS limit should be at least that stringent. The CPV-Towantic plant permit also includes a more stringent GHG limit (809 lb/MWh) than the draft CPS permit. Annual CO_2e limit reflects worst-case emissions from the plant rather than BACT.

Response

Since the applicant has now selected the MI turbine option, the GE turbine option has been removed from the revised draft permit. Thus, the "turbine vendor" part of the comment no longer applies.

DEQ disagrees that a permit condition stating BACT as "absence of duct burning" is necessary. The draft permit does not provide for the installation of duct burners, and any future proposal to install them would require a full PSD permit applicability evaluation.

A lb/MWh "gross" emission limit would not encourage efficiency; a facility's emissions on a "gross" basis would not be impacted by its internal efficiency, whereas a "net" basis emission limit is impacted by and thus encourages such internal efficiency. Additionally, the draft permit's "net" emission limit includes and accounts for all CO_2e emissions from the turbines. For these reasons, DEQ disagrees that a "gross" GHG emission limit is necessary or appropriate to establish BACT for the turbines.

With the elimination of the GE turbine option, DEQ has also lowered the heat rate and lb/MWh limits in the revised draft permit. The revised heat rate and lb/MWh limits are equal to or more stringent than the limits in the Dominion Greensville permit as seen below.

GHG Emission Limits (lb/MWh)

Period (Years)	Dominion Greensville	Draft CPS Permit	Revised Draft CPS Permit
1-6	812	824	812
7-12	828	836	824
13-18	843	848	836
19-24	859	860	847
25-30	875	872	859
31+	890	884	871

The comment also referenced the CPV-Towantic permit and its GHG limit of 809 lb/MWh, however this limit is not comparable to the revised draft permit's GHG limits since the CPV-Towantic emission limit is a one-time only initial-startup standard as opposed to the revised draft permit's rolling 12-month emission limit. The proper comparison to the referenced CPV-Towantic limit in the revised draft permit is the initial heat rate limit of 6,452 Btu/kWh net output for the initial test (Condition #8 of the revised draft permit). Using standard conversions (119.12 pounds per CO_2e per MMBtu), this equates to 769 pounds of CO_2e per megawatt-hour which is more stringent than the CPV-Towantic permit.

The heat rate and lb/MWh limits, not the annual CO_2e mass emission limit, of the revised draft permit represent BACT for GHG emissions from the turbines.

19. Tuning and Water Wash Modeling Analysis

Comment Summary

Modeling analysis failed to account for worst-case emissions allowed for tuning and water *washes.*

Response

DEQ disagrees with the comment. Although these scenarios are not directly modeled, the analysis did consider the impacts related to tuning and water wash events. This is because the modeled emissions scenarios, particularly the cold start scenarios, have much higher emissions and would result in higher modeled concentrations compared to those that would occur during tuning and water washes. The draft permit contained limits for both the GE and MI turbines and the responses below address both turbine models. However, the revised draft permit removes the conditions related to the GE turbine since the applicant has selected the MI turbine option. In addition, the revised draft permit removes on-line water washing for the MI unit (the MI turbines only conduct water washes when they are shutdown). The revised draft permit limits for NO_X and CO will remain the same but remove references to online water washing.

The draft permit included a condition for the GE turbine that limits NO_X and CO emissions to 636 lbs NO_X/turbine/calendar day and 194 lbs CO/turbine/calendar day during maintenance activities, including tuning and water washing. The draft permit also included a condition for the GE turbine that limits NO_X and CO emissions to 312 lbs NO_X/turbine/event and 924 lbs CO/turbine/event during a cold start. The GE cold start events last 66 minutes per turbine.

Both the draft permit and revised draft permit include a condition for the MI turbine that limits NO_X and CO emissions to 703 lbs NO_X/turbine/calendar day and 214 lbs CO/turbine/calendar day during maintenance activities, including tuning. Both the draft permit and revised draft permit also include a condition for the MI turbine that limits NO_X and CO emissions to 60 lbs NO_X/turbine/event and 444 lbs CO/turbine/event during a cold start. The MI turbine cold start events last 48 minutes per turbine.

The table below provides a comparison of daily-modeled emission rates associated with startup and shutdown to the emission limits associated with the daily limits for tuning and water washing. The modeling performed for startup and shutdown conditions for 1-hour NO_2 and 1-hour CO assumed that all three turbines were starting at the same time all 24 hours per day. Therefore, the total daily emissions modeled would be 24 times the cold start emission limits as shown in the table. For 8-hour CO, the modeling assumed one cold start per 8-hour period or three cold starts per day. Therefore, the total daily emissions modeled would be three times the cold start emission limits as shown in the table. The emissions comparison provided in the table below shows that the modeling already conservatively addresses the daily maintenance limits contained in the draft permit.

Comparison of Maintenance Limits vs. Cold Start Emissions

Turbine	Maintenance Limit (lbs/turbine/day)		Cold Start Hourly Limit (lbs/turbine/event)		Cold Start Daily (lbs/turbine/day)		
	NO_X	CO	NO_X	CO	NO_X(1)	CO(1)	CO 8hr(2)
GE	636	194	312	924	7,488	22,176	2,772
MI	703	214	60	444	1,440	10,656	1,332

(1) Modeling for 1-hour NO_2 and 1-hour CO assumed the turbine was cold starting 24 hours

per day.

(2) Modeling for 8-hour CO assumed the turbine was cold starting once in an 8-hour block or 3 times per day.

EPA modeling guidance states that "the most appropriate data to use for compliance demonstrations for the 1-hour NO_2 NAAQS are those based on emissions scenarios that are continuous enough or frequent enough to contribute significantly to the annual distribution of daily maximum 1-hour concentrations." (U.S. Environmental Protection Agency. "Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard", EPA Office of Air Quality Planning and Standards, Research Triangle Park, NC. March 1, 2011) Given the duration and frequency of the tuning events allowed by the revised draft permit, these events qualify as EPA described intermittent source/activities and it would thus be inappropriate to consider these events as part of a 1-hour NO_2 NAAQS demonstration.

20. Cold Start Modeling Analysis

Comment Summary

Modeling analysis failed to evaluate worst-case hourly NO_X or CO emissions allowed under the draft permit for cold starts of the GE 7HA.02 combustion turbine generators.

Response

The draft permit contained limits for both the GE and MI turbines. However, the revised draft permit removes the conditions related to the GE turbine since the applicant has selected the MI turbine option.

The startup modeling for 1-hour NO_2 and 1-hour CO uses the data provided in the application for each turbine option. For the GE turbine, the application states a cold start time of 66 minutes. During the 66-minute startup event, the total emissions of NO_X and CO are 312 and 924 lbs per turbine, respectively. To properly model the 1-hour averaging period for NO_2 and CO, the total lbs/event emission rate is scaled by the fraction of 60/66 to estimate the hourly emission rate. As an example, 312 lbs of NO_X/66 minutes would equate to 4.73 lbs/minute. At 60 minutes, this would equate to 283.64 lbs/hr (which is equivalent to the modeled emission rate in Table 6-7 of the air permit application). Finally, it is important to understand the 1-hour modeling assumes a startup for every hour of the year, which is a highly conservative assumption.

The modeling for 8-hour CO uses a similar methodology. The total 924 lbs/event/turbine of CO are modeled for the 8-hour averaging period. The 8-hour emission rate is also based on the start time of 66 minutes over the 480-minute 8-hour averaging period. This would equate to an emission rate of 924 lbs per turbine multiplied by the ratio of 66 minutes/480 minutes, or 127.05 lbs/hr/turbine. The remaining 414 minutes of the 8-hour averaging period is modeled using the turbine 100% normal operating load emission rate pro-rated based on 414 minutes/480 minutes of operation in the 8-hour averaging period. The 8-hour CO modeling assumes three startups per 24-hour period for each day in the year, which is a highly conservative assumption.

In order to further address the comment's concerns, DEQ evaluated the impact of assuming all startup emissions for the GE turbines might occur in 60 minutes rather than 66 minutes as stated in the application. Specifically, the model was run using a NOx emission rate of 312 lbs/hr for each of the three Chickahominy GE turbines. This assumption would increase the total concentration by 2.23 μg/m^3 from the original modeling result and would remain in compliance with the 1-hour NO_2 NAAQS as illustrated in the table below. Again, the GE turbine option is not included in the revised draft permit.

60-Minute Startup Scenario Modeling Results – GE Units

Cold Start Modeling Scenario	Total Concentration (μg/m^3)	NAAQS (μg/m^3)
GE	182.46	188

DEQ, therefore, disagrees with the comment's assertion that the startup modeling for the draft permit did not address worst-case hourly NO_X or CO emissions for the GE units. However, the GE turbine option has been removed from the revised draft permit, which should ultimately alleviate the comment's concerns.

21. Background NO_2 concentrations

Comment Summary

The background 1-hr NO_2 concentrations used in the 1-hr NO_2 NAAQS modeling have not been justified. The use of a proper background 1-hour NO2 concentration is extremely important given how close the modeling of the Chickahominy plant when equipped with GE 7HA.02 turbines is to the 1-hour NO2 NAAQS.

Response

The approach used by DEQ to pair the modeled concentrations with the monitored concentrations is consistent with EPA guidance. Specifically, the ambient background utilized for the 1-hour NO_2 NAAQS modeling is developed using EPA prescribed methodology as described in the EPA March 1, 2011 guidance "Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO_2, National Ambient Air Quality Standard." The 1-hour NO_2 NAAQS modeling utilized the season and hour of day varying background concentration option in AERMOD to combine the modeled and monitored concentrations. In the March 1, 2011 guidance, EPA indicates the appropriateness of this approach and provides specific guidance in developing this data set on page 19 (last paragraph). EPA's approach outlines a procedure on how to calculate a design concentration based on the form of the 1-hour NO_2 NAAQS for each season and hour of day combination based on the available data. This matrix of design concentrations is then input to AERMOD and used to calculate the total concentration (model plus ambient background) for then comparing to the NAAQS.

The Shirley Plantation monitor ((75-B) Charles City Co.) was selected for this analysis based on its proximity to the proposed project and the overall positive bias relative to existing air quality at the project site. Specifically, the Shirley Plantation monitor is conservatively representative because the monitor is located closer to an industrialized area with higher emissions when compared to the project site and captures those impacts.

Both Chapter 4 of the modeling protocol (November 2018) and Section 6.8 of the air permit application (January 2019 (Revision 3)), provide the basis for monitor selection and are already part of the record. The underlying monitoring data and the calculation methodology are also contained in the modeling archive and are included in the project record.

Lastly, it is important to note that the GE turbine option has been removed from the revised draft permit, and this issue therefore becomes ultimately irrelevant. The MI turbine option demonstrates compliance with both the season and hour of day varying background concentration and the use of the 1-hr NO_2 design value (38 ppb or 71.44 μg/m^3) for each hour of the year as suggested by the comment. The table below illustrates this fact. DEQ supports the use of season and hour of day varying background, as was implemented in the original modeling. The assumption of a design value for each hour of the year is needlessly conservative in this case.

1-Hour NO_2 NAAQS Modeling - MI Turbines

Background Calculation Method	Total Modeled Concentration (μg/m^3)	Ambient Background Concentration (μg/m^3)	Total Concentration (μg/m^3)	NAAQS (μg/m^3)
Season, Hour of Day	98.13	36.44	134.57	188
Design Value	98.13	71.44	169.57	188

22. Cumulative NO_2 Modeling

Comment Summary

The cumulative NO_2 modeling is flawed because Chickahominy Power failed to model allowable NOx emissions from the proposed Charles City Combined Cycle (C4GT) Power Plant

Response

The recently permitted C4GT power plant was included in the nearby source inventory that was input to the air quality model. The modeling performed to assess compliance with the 1-hour NO_2 NAAQS for the proposed project did evaluate the proposed C4GT plant at its proper 100% full load emission rate. Specifically, the emissions modeled are 3.67786 g/s (29.19 lbs./hr). This rate is contained in the C4GT application and in the underlying DEQ engineering analysis for this project. The NO_X emission rate for both turbine options is identical.

The comment's calculation of the NO_X emission rate used in the modeling of 24.13998 lbs./hr seems to be erroneous. The comment also calculated NO_X emission rates of 29.24223 and 30.35075 lbs/hr/turbine, respectively for the GE and Siemens turbines proposed at C4GT. These are close, but not identical to, the rates used in the modeling and calculated by DEQ in its engineering analysis. The differences, however, are insignificant with respect to NAAQS compliance.

The comment contends that 1-hour NO_2 NAAQS modeling should have been performed assuming that both Chickahominy and C4GT are undergoing cold start operations at the same time. This is a highly unlikely event and most certainly is considered an intermittent activity not subject to modeling. EPA specifically addresses how these intermittent operating scenarios should be addressed in its March 1, 2011guidance "Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO_2, National Ambient Air Quality Standard."

Specifically, the EPA guidance states the following:

…"Given the implications of the probabilistic form of the 1-hour NO_2 NAAQS discussed above, we are concerned that assuming continuous operations for intermittent emissions would effectively impose an additional level of stringency beyond that intended by the level of the standard itself. As a result, we feel that it would be inappropriate to implement the 1-hour NO_2 standard in such a manner and recommend that compliance demonstrations for the 1-hour NO_2 NAAQS be based on emission scenarios that can logically be assumed to be relatively continuous or which occur frequently enough to contribute significantly to the annual distribution of daily maximum 1-hour concentrations. EPA believes that existing modeling guidelines provide sufficient discretion for reviewing authorities to exclude certain types of intermittent emissions from compliance demonstrations for the 1-hour NO_2 standard under these circumstances.

EPA's Guideline on Air Quality Models provides recommendations regarding air quality modeling techniques that should be applied in preparation or review of PSD permit applications and serves as a "common measure of acceptable technical analysis when supported by sound scientific judgment." 40 C.F.R. Part 51, Appendix W, section 1.0.a. While the guidance establishes principles that may be controlling in certain circumstances, the guideline is not "a strict modeling 'cookbook'" so that, as the guideline notes, "case-by-case analysis and judgment are frequently required." Section 1.0.c. In particular, with respect to emissions input data, section 8.0.a. of Appendix W establishes the general principle that "the most appropriate data available should always be selected for use in modeling analyses," and emphasizes the importance of "the exercise of professional judgement by the appropriate reviewing authority" in determining which nearby sources should be included in the model emission inventory. Section 8.2.3.b.

For the reasons discussed above, EPA believes the most appropriate data to use for compliance demonstrations for the 1-hour NO_2 NAAQS are those based on emissions scenarios that are continuous enough or frequent enough to contribute significantly to the annual distribution of daily maximum 1-hour concentrations. Section 8.1.1.b of the guideline also provides that "[t]he appropriate reviewing authority should be consulted to determine appropriate source definitions and for guidance concerning the determination of emissions from and techniques for modeling various source types."
When EPA is the reviewing authority for a permit, for the reasons described above, we will consider it acceptable to limit the emission scenarios included in the modeling compliance

demonstration for the 1-hour NO_2 NAAQS to those emissions that are continuous enough or frequent enough to contribute significantly to the annual distribution of daily maximum 1-hour concentrations. Consistent with this rationale, the language in Section 8.2.3.d of Appendix W states that "[i]t is appropriate to model nearby sources only during those times when they, by their nature, operate at the same time as the primary source(s) being modeled." While we recognize that these intermittent emission sources could operate at the same time as the primary source(s), the discussion above highlights the additional level of conservatism in the modeled impacts inherent in an assumption that they do in fact operate simultaneously and continuously with the primary source(s).

The rationale regarding treatment of intermittent emissions applies for both project emissions and any nearby or other background sources included in the modeling analysis."…

EPA's 2011 guidance contends that if it were the reviewing authority, the modeling for 1-hour NO_2 NAAQS compliance would be limited to those emissions that are continuous enough or frequent enough to contribute significantly to the annual distribution of daily maximum 1-hour concentrations. Given the high unlikelihood of both C4GT and Chickahominy undergoing a simultaneous cold start, DEQ concurs that this event is not required to be modeled as part of the 1-hour NO_2 NAAQS assessment.

The assertion regarding the modeling of water washing and tuning is addressed, in part, under the response "Modeling of Water Washing and Tuning." (Comment #19) Modeling of the cold start scenario 24 hours per day for the entire year clearly results in greater emissions and subsequent air quality impacts when compared to the daily water washing and tuning limits included in either the Chickahominy or C4GT permits.
DEQ is providing additional technical information to address the comment's concerns. Specifically, AERMOD was run using an assumption that both of the C4GT turbines were in cold start mode simultaneously with the Chickahominy units. The results of this analysis continue to illustrate that, even under these very conservative and unlikely conditions, the proposed facility remains in compliance with the 1-hour NO_2 NAAQS as summarized in the table below. In fact, there was no change in the maximum impact for either turbine option because the stack plumes from the two facilities do not interact at the maximum impact receptor.

Simultaneous Cold Start Modeling Results

Cold Start Modeling Scenario	Total Concentration ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)
GE	180.23	188
MI	134.57	188

In summary, the original analyses performed in support of the draft permit is appropriate, consistent with EPA guidance, and protective of air quality.

<u>OTHER SPECIFIC COMMENTS</u>

23. Low Load Operations

Comment Summary

One comment states that regarding natural gas-fired combined cycle power plants are only 60% efficient, at most. At low loads, CO and PM10 emissions may be higher. DEQ must assess the impacts of operating factors. BACT for criteria pollutants and MACT for hazardous air pollutants are the standards required for the Chickahominy Power plant

Response

DEQ did consider low load operation of the combustion turbines in its evaluation (see engineering analysis) of BACT for the proposed facility under worst-case conditions. Other than startup, shutdown and tuning, the BACT control equipment requirements and emission limits apply at all times (including low load operations). There are no MACT standards for an area source of hazardous air pollutants from a natural-gas power plant. Toxic pollutant emission limits in the draft permit are based on Virginia's toxic pollutant regulations (9VAC5 Chapter 60 Article 5).

24. Study Area Radius

Comment Summary

One comment raised concerns regarding the size of the modeling area and requested that the study area extend 5-7 miles in order to determine impacts on their subdivision

Response

The air quality analyses were conducted in accordance with Virginia and federal permitting regulations and guidance in order to assess compliance of projected emissions from the proposed facility with all applicable NAAQS, PSD increments, and SAAC. The modeling analyses used a dense receptor grid extended to 20 kilometers (12.4 miles) from the proposed facility. The results of the modeling analyses indicate all modeled concentrations outside of the facility boundary will be below the applicable NAAQS, PSD increments, and SAAC. The highest modeled concentrations are located on or near the facility's property line (i.e., generally within approximately 1 kilometer or less). Pollutants disperse downwind beyond this immediate area and will not cause or contribute to any violations of air quality standards. In addition, all surrounding counties are currently in attainment with applicable air quality standards.

In addition, local and regional air quality impacts for ozone were evaluated and are addressed elsewhere in this document (Comment #5).

25. Particulate Matter Continuous Emission Monitoring System (CEMS)

Comment Summary

One comment stated that DEQ should require a particulate matter CEMS

Response

The draft permit requires CEMS for carbon monoxide (CO) and Nitrogen Oxides (NOx) from the combustion turbines to determine compliance with the draft permit's CO and NOx emission limits. Compliance with the CO and NOx emission limits will also provide assurance that the combustion turbines are being operated consistent with good operating practices and therefore provide an indirect indication of particulate matter emissions (natural gas-fired cnombustion equipment operating with good operating practices have low particulate matter emissions; see DEQ's engineering analysis). Additionally, the draft permit requires the permittee to monitor the quantity of fuel combusted and the fuel sulfur content, to periodically conduct performance tests for PM and VOC and to maintain records of all emission data. The permittee must report all emission data to DEQ each year and is subject to inspection by DEQ for all aspects of compliance with their permit. In any case, a significant fraction of the particulate matter (PM-10 and PM-2.5) emitted from the combustion turbines will be condensable PM which is not measured by existing PM CEMS technology. The draft permit's existing monitoring requirements will ensure compliance with the draft permit's PM emission limits and DEQ disagrees that a PM CEMS should be required.

26. "Good Neighbor" Concerns

Comment Summary

One comment stated that Virginia should be a "good neighbor" regardless of EPA's current posture and also referenced the air pollution control requirements imposed on Dominion in 2003. Fracked gas powered plant releases methane, a powerful GHG. Renewables are more cost-effective. Power demand is flat.

Response

See Comments/Responses #1 and #3 as well as the 2003 Clean Air Act Settlement and Good Neighbor Requirements discussions below. The Good Neighbor requirements are not directly applicable to PSD permits, but the discussions may address the comment's concerns.

Dominion Virginia Energy/VEPCO 2003 Clean Air Act Settlement

In 2003, EPA and the Department of Justice published a settlement with VEPCO, now called Dominion Virginia Energy (Dominion), that required Dominion to reduce air emissions from several facilities through the use of control equipment, fuel switching, and unit closures. The Commonwealth of Virginia was a party to the settlement. The settlement stemmed from allegations that Dominion circumvented Prevention of Significant Deterioration New Source Review permitting requirements. This settlement continues today to provide federally enforceable limitations on facilities such as Chesterfield Power Station in Virginia. Violations noted on the EPA website concerning the settlement make no mention of a good neighbor air policy.[9] Therefore, the context of the comment's statement regarding the proposed Chickahominy facility is unclear, and DEQ disagrees that the Dominion Virginia Energy/VEPCO settlement in any way affects the issuance of the draft permit.

Good Neighbor Requirements under the Clean Air Act

The Clean Air Act (CAA), under § 110(a)(2)(D)(i)(I) requires each state to submit to EPA new or revised state implementation plans (SIPs) that "contains adequate provisions … prohibiting, consistent with the provisions of this subchapter, any source or other type of emissions activity within the state from emitting any air pollutant in amounts which will … contribute significantly

[9] https://www.epa.gov/enforcement/virginia-electric-and-power-company-vepco-clean-air-act-caa-settlement#violations

to nonattainment in, or interfere with maintenance by, another state with respect to any such national primary or secondary ambient air quality standard." EPA often refers to this section as the good neighbor provisions and to SIP revisions addressing this requirement as good neighbor SIPs.

Under this section of the CAA, EPA has developed and Virginia has participated in several important control programs. The NO_X Budget Trading Program (NBTP) regulated nitrogen oxides (NO_X) emissions from fossil fuel fired power plants and large industrial fossil fuel fired boilers to address good neighbor provisions for the 1990 ozone NAAQS, set at 0.12 parts per million (ppm) ozone over a one-hour average. The Clean Air Interstate Rule (CAIR) regulated NO_X and sulfur dioxide (SO_2) emissions from fossil fuel fired power plants to address the 1997 ozone NAAQS, set at 0.08 ppm over an eight-hour average, and the 1997 fine particulate (PM-2.5) NAAQS, set at 35 $\mu g/m^3$ on a 24-hour average and 15.0 $\mu g/m^3$ on an annual average. The Cross State Air Pollution Rule (CSAPR) further regulated NO_X and SO_2 emissions to address the 2006 PM-2.5 NAAQS, set at 35 $\mu g/m^3$ on a 24-hour average and 12.0 $\mu g/m^3$ on an annual average. The Cross State Air Pollution Rule Update (CSAPR Update) reduced NO_X emissions from fossil fuel fired power plants to address the 2008 ozone NAAQS, set at 0.075 ppm over an eight-hour average. The CSAPR Update noted that at the time of promulgation EPA considered the rule only a partial remedy addressing emissions from the power sector.

On August 21, 2012, in the EME Homer City decision, the U.S. Court of Appeals for the D.C. Circuit found that a state was not required to submit a SIP pursuant to § 110(a)(2)(D)(i)(I) until EPA defined a state's contribution to nonattainment or interference with maintenance in another state. However, on April 29, 2014, the Supreme Court of the United States reversed the EME Homer City decision and found that the CAA does not require EPA to quantify a state's obligation under that section before states are required to submit such SIPs. On July 13, 2015, EPA published Findings of Failure to Submit a Section 110 State Implementation Plan for Interstate Transport for the 2008 National Ambient Air Quality Standards for Ozone (80 FR 39961). This document determined that 24 states, including Virginia, failed to submit SIPs satisfying the requirements §110(a)(2)(D)(i)(I). These findings of failure to submit established a 24-month deadline for EPA to promulgate a federal implementation plan (FIP) to address the interstate transport SIP requirements pertaining to significant contribution to nonattainment and interference with maintenance, unless, prior to EPA promulgating a FIP, the state submits, and EPA approves, a SIP that meets these requirements. The Commonwealth of Virginia submitted a final SIP revision addressing the other emissions sectors on August 27, 2018. Virginia has, therefore, fully met all CAA requirements regarding the 2008 ozone NAAQS and the good neighbor provisions.

Virginia is currently examining the existing modeling and guidance documents regarding the 2015 ozone NAAQS good neighbor provisions and will be developing a SIP revision to address these requirements.

Important to note is that Virginia's emissions of ozone precursors are decreasing. EPA's NEI data[10] show that between 2008 and 2014, anthropogenic emissions of volatile organic compounds (VOCs) have decreased from 341,000 tons per year (tpy) to 273,381 tpy and

[10] https://www.epa.gov/air-emissions-inventories/national-emissions-inventory-nei

anthropogenic emissions of NO_X have decreased from 376,293 tpy to 283,750 tpy. EPA has not yet released preliminary NEI data for 2017. However, the decreasing trend is expected to continue due to the application of significant federal and state control programs as well as technological advances and other changes.

One emissions sector where the emissions decreases are especially prominent is the electrical generating sector. Large, fossil fuel fired electrical generating units (EGUs) must report emissions quarterly to EPA's Clean Air Markets Division (CAMD).[11] Between 2003 and 2017, NO_X emissions reported to CAMD from Virginia facilities dropped from 77,912 tpy to 16,545 tpy. During that same period, SO_2 emissions reported to CAMD from Virginia facilities dropped from 215,740 tpy to 5,791 tpy. These reductions occurred even though measured gross load in megawatt-hours increased during that period by approximately 24%. These NO_X and SO_2 emissions decreases are due to a number of control programs including those mentioned above (NBTP, CAIR, CSAPR, and CSAPR Update) as well as the construction and operation of new, low-emitting units that replaced older, inefficient units in the EGU fleet. Plants such as the proposed Chickahominy facility are not only cleaner than older EGUs, they are more efficient and economical to run and may supplant energy created by older, less efficient units, further reducing emissions from this sector.

DEQ, therefore, disagrees with the assertion that the draft permit will impede Virginia from meeting its good neighbor requirements under § 110(a)(2)(D)(i)(I) of the CAA.

27. General Electric (GE) Turbines should be BACT

<u>Comment Summary</u>
One comment stated that, with the understanding that the facility has chosen to construct the MI turbines, the MI turbines emit more pollutants than the GE turbines on an annual basis so the MI turbines are not BACT.

<u>Response</u>
The selection of one turbine model over another would historically be considered "re-defining" the proposed source in the context of the PSD permitting program and would therefore not be a consideration in a PSD BACT analysis. Also, annual emission limits are not typically used to establish BACT in PSD permits. Instead, as is the case for the draft permit, short-term emission limits are used to implement BACT in PSD permits. It should be noted that the short-term emission limits (representing BACT) are identical for the two turbine options for most pollutants (including VOC) during normal operations. One notable exception is that the short-term emission limits for PM, PM10 and PM2.5 are <u>lower</u> (0.0052 pound per million BTU vs. 0.0069 pounds per million BTU) for the MI turbine option than for the GE turbine option. For SU/SD events, the proposed permit also establishes short-term (pound per event) emission limits, as well as limiting the duration of such events and requiring the operation of the "normal operations" control mechanisms as technologically feasible to minimize emissions. While the short-term VOC SU/SD emissions for the MI turbine option are <u>greater</u> than the GE turbine option (resulting in the greater annual emissions limit noted by the comment), the short-term NOx and

[11] https://www.epa.gov/airmarkets

CO SU/SD emissions for the MI turbine option are lower than the GE turbine option. The lower SU/SD NOx emissions associated with the MI turbine result in a significantly lower cumulative NO_2 ambient concentration for the project (see Comments #22 and #28). With the elimination of GE turbine option, DEQ also imposed a more stringent GHG BACT (lb/MWh) limit (See Comment #18). For these reasons, DEQ does not agree that the proposed emission limits for the MI turbine option do not reflect BACT.

28. Post-Construction Ambient Monitoring

Comment Summary

One comment stated that DEQ should require additional post-construction ambient monitoring since the existing ambient monitoring network is not sited downwind of the proposed CPS (and the previously permitted C4GT project).

Response

DEQ has removed the GE turbine option from the draft permit, and none of the modelled impacts from the CPS are within 28% of an applicable NAAQS (see DEQ's engineering analysis and modeling report and as excerpted below). Given the conservative nature of the air quality analysis, DEQ as therefore determined that post-construction ambient monitoring is not necessary.

NAAQS Modeling - Cumulative Impact Results
MI Turbines

Pollutant	Averaging Period	Total Modeled Concentration ($\mu g/m^3$)	Ambient Background Concentration ($\mu g/m^3$)	Total Concentration ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)
NO_2	1-hour	134.57	--(1)	134.57	188
NO_2	Annual	3.63	9.4	13.03	100
PM-10	24-hour	5.30	23	28.30	150
PM-2.5	24-hour	3.60	16	19.60	35
PM-2.5	Annual	0.65	7.3	7.95	12

(1) Season and hour of day varying

29. Cumulative Modeling – Existing Landfill

Comment Summary

Some comments raised the issue of the nearby BFI Waste Systems - Charles City Road Landfill (CCRL) and the cumulative impacts of the CPS with the landfill.

Response

The emissions from the existing CCRL were included in the cumulative air quality analyses described in the response to Comment #22 above. In addition to NO_2, this was also the case for the cumulative analyses for the other NAAQS pollutants. As previously discussed, there are no modelled impacts that exceed an applicable air quality standard.

APPENDIX A

VIRGINIA GREENHOUSE GAS MITIGATION ACTIONS

Carbon Trading Rule – Starting with Governor McAuliffe and continuing with Governor Northam, the Commonwealth has developed a proposed power sector carbon trading rule that would allow Virginia to link to other existing regional trading programs such as the Regional Greenhouse Gas Initiative (RGGI). The Virginia State Air Pollution Control Board voted 5-2 on April 19, 2019 to approve a revised version of the rule[12]. The revised rule establishes a lower initial year emissions budget in 2020 of 28 million tons.

Clean Power Legislation – As part of the comprehensive Grid Transformation and Security Act of 2018 (GTSA), legislation from the 2018 General Assembly session that Governor Northam supported and signed, a significant commitment and investment in clean renewable energy generation and energy efficiency has established to be implemented over the next ten years. First there is a commitment to up to 5,000 megawatts of renewable energy to be implemented by the state's publically regulated utilities. In addition, these utilities will invest about $1 billion dollars in energy efficiency projects. These commitments have now been included in the updated 2018 Virginia Energy Plan.

Electric Vehicle Charging Infrastructure – Virginia has been certified as formal beneficiary under the Volkswagen mitigation settlement under which the Commonwealth will receive $93 million dollars to distribute to various mitigation projects. As part of the overall mitigation plan, Virginia has completed a request for proposal (RFP) for installing a statewide electric vehicle charging infrastructure for $14 million dollars and awarded a contract to EVGo to develop the charging network.

Electric Transit buses – Also under the Volkswagen mitigation settlement trust, Governor Northam recently announced that the Commonwealth will invest another $14 million dollars to fund the deployment of all-electric transit buses in Virginia. This program will provide funding through a new Clean Transportation Voucher Program to replace heavy and medium-duty polluting vehicles with cleaner vehicles.

Renewable Permitting – DEQ has developed regulations for the construction and operation of renewable energy projects of 150 MW or less, and has, as of May 1, 2019, issued at least 34 permits for more than 1,114 MW of solar and wind power.

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[12] From the 2019 Acts of Assembly: Item 4-5.11 LIMITATIONS ON USE OF STATE FUNDING "Notwithstanding any other provision of the Code of Virginia, no expenditures from the general, special, or other nongeneral fund sources from any appropriation by the General Assembly shall be used to support membership or participation in the Regional Greenhouse Gas Initiative (RGGI) until such time as the General Assembly has approved such membership as evidenced by language authorizing such action in the Appropriation Act, with the exception of any expenditures required pursuant to any contract signed prior to the passage of this act by the General Assembly, nor shall any RGGI auction proceeds be used to supplement any appropriation in this act without express General Assembly approval."

TCI – Virginia has officially joined the Transportation and Climate Initiative to work collaboratively with Northeast and Mid-Atlantic states on reducing carbon pollution from the transportation sector. The transportation sector is the largest emitter of greenhouse gases in Virginia.

Workgroup for Methane Leakage from Natural Gas Infrastructure – At the direction of the Governor, DEQ has established an ad hoc work group to advise and assist DEQ in the development of a framework for limiting methane leakage from natural gas infrastructure. The group will support DEQ in its collection and evaluation of data to inform any future regulation development process.

Workgroup for Methane Leakage from Landfills – At the direction of the Governor, DEQ will be establishing an ad hoc work group to develop a framework for limiting methane leakage from landfills.

PREVENTION OF SIGNIFICANT DETERIORATION PERMIT
STATIONARY SOURCE PERMIT TO CONSTRUCT AND OPERATE
This permit includes designated equipment subject to
New Source Performance Standards (NSPS).

In compliance with the Federal Clean Air Act and the Commonwealth of Virginia Regulations for the Control and Abatement of Air Pollution,

Balico LLC/Chickahominy Power
1380 Coppermine Road, Suite 115
Herndon, Virginia 20171
Registration No.: 52610

is authorized to construct and operate

an electric power generation facility

located at

the east side of State Road 106 (Roxbury Rd), along
Chambers/Landfill Road, Charles City, VA

in accordance with the Conditions of this permit.

Approved on DRAFT.

Deputy Regional Director
Department of Environmental Quality

Permit consists of 72 pages.
Permit Conditions 1 to 0.

INTRODUCTION

This permit approval is based on the permit application dated February 22, 2017; including amendment information dated November 2, 2018. Any changes in the permit application specifications or any existing facilities which alter the impact of the facility on air quality may require a permit. Failure to obtain such a permit prior to construction may result in enforcement action. In addition, this facility may be subject to additional applicable requirements not listed in this permit.

Words or terms used in this permit shall have meanings as provided in 9 VAC 5-10-20 of the State Air Pollution Control Board Regulations for the Control and Abatement of Air Pollution. The regulatory reference or authority for each condition is listed in parentheses () after each condition.

Annual requirements to fulfill legal obligations to maintain current stationary source emissions data will necessitate a prompt response by the permittee to requests by the DEQ or the Board for information to include, as appropriate: process and production data; changes in control equipment; and operating schedules. Such requests for information from the DEQ will either be in writing or by personal contact.

The availability of information submitted to the DEQ or the Board will be governed by applicable provisions of the Freedom of Information Act, §§ 2.2-3700 through 2.2-3714 of the Code of Virginia, § 10.1-1314 (addressing information provided to the Board) of the Code of Virginia, and 9 VAC 5-170-60 of the State Air Pollution Control Board Regulations. Information provided to federal officials is subject to appropriate federal law and regulations governing confidentiality of such information.

Equipment List – Equipment at this facility consists of:

Equipment to be constructed:

Ref. No.	Equipment Description	Rated Capacity	Federal Requirements
CT-1	Mitsubishi Hitachi Power Systems (MHPS) M501JAC combustion turbine generator	4,070 MMBtu/hr CT (HHV)	NSPS, Subpart KKKK
CT-2	Mitsubishi Hitachi Power Systems (MHPS) M501JAC combustion turbine generator	4,070 MMBtu/hr CT (HHV)	NSPS, Subpart KKKK
CT-3	Mitsubishi Hitachi Power Systems (MHPS) M501JAC combustion turbine generator	4,070 MMBtu/hr CT (HHV)	NSPS, Subpart KKKK
HRSG1, 2, & 3 each with a steam turbine generator	Mitsubishi heat recovery steam generators (HRSGs) with steam turbine generators	178 MW each at ISO	None

Ancillary equipment:

Ref. No.	Equipment Description	Rated Capacity	Federal Requirements
B-1	Auxiliary Boiler (natural gas-fired)	84 MMBtu/hr (HHV)	NSPS Subpart Dc
B-2	Auxiliary Boiler (natural gas-fired)	84 MMBtu/hr (HHV)	NSPS Subpart Dc
FGH-1	Fuel Gas Heater (natural gas-fired)	12 MMBtu/hr each (HHV)	NSPS Subpart Dc
FGH-2	Fuel Gas Heater (natural gas-fired)	12 MMBtu/hr each (HHV)	NSPS Subpart Dc
FGH-3	Fuel Gas Heater (natural gas-fired)	12 MMBtu/hr each (HHV)	NSPS Subpart Dc
EG-1	Emergency Generator (S15 ULSD)	3000 kW	NSPS IIII, MACT ZZZZ

Ref. No.	Equipment Description	Rated Capacity	Federal Requirements
FWP-1	Fire Water Pump (S15 ULSD)	376 bhp	NSPS IIII, MACT ZZZZ
CB	Electrical Circuit Breakers	22,800 lbs SF_6 total	None
NGL-1	Fugitive equipment leaks from natural gas piping components	---	None
T-1	ULSD storage tank	572 gallons	None
T-2	ULSD storage tank	2,500 gallons	None

Specifications included in the above table are for informational purposes only and do not form enforceable terms or conditions of the permit.

PROCESS REQUIREMENTS

Combustion Turbine Generators (CT-1, CT-2, CT-3)

Emission Controls: Combustion Turbine Generators - Nitrogen oxide (NO_x) emissions from each of the combustion turbine generators (CT-1, CT-2, CT-3) shall be controlled by dry, low NO_x burners and selective catalytic reduction (SCR) with a NO_x performance of 2.0 ppmvd at 15% O_2. The low NO_x burners shall be installed and operated in accordance with manufacturer's specifications. The SCR shall be provided with adequate access for inspection and shall be in operation when the combustion turbine generators are operating (at all times except during startup and shutdown, as defined in Condition 0).
(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

Monitoring Devices: Combustion Turbine Generators - SCR - Each SCR system shall be equipped with devices to continuously measure and record ammonia feed rate and catalyst bed inlet gas temperature. Each monitoring device shall be installed, maintained, calibrated and operated in accordance with approved procedures that shall include, as a minimum, the manufacturer's written requirements or recommendations. Each monitoring device shall be provided with adequate access for inspection and shall be in operation when the SCR system is operating. To ensure good performance of the SCR, the devices used to continuously measure the ammonia feed rate and catalyst bed inlet temperature on the SCR shall be observed by the permittee with a frequency sufficient to ensure good performance of the SCR system, but not less than once per day of operation.
(9 VAC 5-50-20 C, 9 VAC 5-50-50 H and 9 VAC 5-80-1705 B)

Emission Controls: Combustion Turbine Generators – Carbon monoxide (CO) emissions from each of the combustion turbine generators (CT-1, CT-2, CT-3) shall be controlled by an oxidation catalyst and good combustion practices (e.g. controlled fuel/air mixing, adequate temperature, and gas residence time). The oxidation catalyst shall be provided with adequate access for inspection and shall be in operation when the combustion turbine generators are operating (at all times except during startup and shutdown, as defined in Condition 0).
(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

Emission Controls: Combustion Turbine Generators – Volatile organic compound (VOC) emissions from each of the combustion turbine generators (CT-1, CT-2, CT-3) shall be controlled by an oxidation catalyst and good combustion practices (e.g. controlled fuel/air mixing, adequate temperature, and gas residence time). The oxidation catalyst shall be provided with adequate access for inspection and shall be in operation when the combustion

turbine generators are operating (at all times except during startup and shutdown, as defined in Condition 0).
(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

Monitoring Devices: Oxidation Catalyst - Each oxidation catalyst shall be equipped with a device to continuously measure and record temperature at the catalyst bed inlet and outlet. Each monitoring device shall be installed, maintained, calibrated and operated in accordance with approved procedures that shall include, at a minimum, the manufacturer's written requirements or recommendations. Each monitoring device shall be provided with adequate access for inspection and shall be in operation when the oxidation catalyst is operating. To ensure good performance of the oxidation catalyst system, the device used to continuously measure and record the catalyst bed inlet and outlet gas temperature on the oxidation catalyst shall be observed by the permittee with a frequency sufficient to ensure good performance of the oxidation catalyst system, but not less than once per day of operation.
(9 VAC 5-50-20 C, 9 VAC 5-50-50 H and 9 VAC 5-80-1705 B)

Emission Controls: Combustion Turbine Generators – Sulfur dioxide (SO_2) and sulfuric acid mist (H_2SO_4) emissions from each of the combustion turbine generators (CT-1, CT-2, CT-3) shall be controlled by the use of pipeline-quality natural gas with a maximum sulfur content of 0.4 grains per 100 standard cubic feet (scf), on a 12-month rolling average. Compliance will be based on fuel monitoring results as required by Condition 0.
(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

Emission Controls: Combustion Turbine Generators – Particulate Matter (PM, PM_{10}, $PM_{2.5}$) emissions from each of the combustion turbine generators (CT-1, CT-2, CT-3) shall be controlled by good combustion practices (e.g. controlled fuel/air mixing, adequate temperature, and gas residence time) and the use of pipeline-quality natural gas with a maximum sulfur content of 0.4 grains per 100 scf, on a 12-month rolling average.
(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

Emission Controls: Combustion Turbine Generators – Greenhouse gas emissions (including carbon dioxide, methane, and nitrous oxide), as CO_2e from the combustion turbine generators (CT-1, CT-2, CT-3) shall be controlled by the use of low carbon fuel (natural gas) and high efficiency design and operation of the combustion turbine generators (CT-1, CT-2, CT-3 and steam turbine generator). The heat rate of the combustion turbine generators (CT-1, CT-2, CT-3 and steam turbine generator) at full load, corrected to ISO conditions, and providing for incremental degradation of the units, shall not exceed the following:

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

Compliance shall be demonstrated as contained in Conditions 0 and 0. The Year is defined in Condition 0.

(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

Startup/Shutdown: Combustion Turbine Generators –The permittee shall comply with the requirements of this permit at all times except where noted by a specific condition. For the purpose of this permit, this condition defines startup and shutdown operating scenarios for the combustion turbine generators (CT-1, CT-2, CT-3).

Startup periods are defined as follows:

For the purpose of this permit, startup is defined as the time from combustion turbine ignition to the HRSG stack NO_x and CO steady state emission compliance (see Condition 0) or the duration of the event periods indicated in items 0 through 0 below, whichever is shorter:

Cold Startup Event: cold startup is defined as restarts made 48 hours or more after shutdown. Cold startup events shall not exceed 42 minutes per occurrence.

Warm Startup Event: warm startup is defined as restarts made more than 8 but less than 48 hours after shutdown. Warm startup events shall not exceed 42 minutes per occurrence.

Hot Startup Event: hot startup is defined as restarts made less than 8 hours after shutdown. Hot startup events shall not exceed 42 minutes per occurrence.

Shutdown Event: For the purpose of this permit, a shutdown event is defined as the moment at which either the HRSG stack NOx or CO emissions exceed steady state compliance (see Condition 0) following a normal stop signal, until the cessation of fuel firing in the combustion turbine generators (CT-1, CT-2, CT-3). Shutdown shall not exceed 15 minutes per occurrence.

If the SCR was not engaged during startup of a particular combustion turbine (including ammonia injection), the failure of that startup shall not be considered a shutdown as defined in 0.

The permittee shall operate the Continuous Emission Monitoring System (CEMS) during periods of startup and shutdown.

The permittee shall record the time, date and duration of each startup and shutdown event. The records must include calculations of NO_x and CO emissions during each event based on the CEMS data. These records must be kept for five years following the date of such event.

If the applicable NOx and CO emission limits in Condition 1.c are exceeded during these events, the recorded emissions shall be included in the associated quarterly excess emission report.

During startup and shutdown, the combustion turbine generator SCR system, including ammonia injection, and oxidation catalyst shall be operated in a manner to minimize emissions, as technologically feasible, and following the SCR manufacturer's written protocol or best engineering practices for minimizing emissions. Where best practices are used, the permittee shall maintain written documentation explaining the sufficiency of such practices. If such practices are used in lieu of the manufacturer's protocol, the documentation shall justify why the practices are at least equivalent to manufacturer's protocols with respect to minimizing emissions.

(9 VAC 5-50-280 and 9 VAC 5-80-1705)

Alternate Operating Scenario: Combustion Turbine Generators – Tuning Events – Periodic burner tuning is done by the permittee as part of the regularly scheduled procedures conducted on the CTs to maintain the high-efficiency operation of those units. The following conditions apply to these alternative operating scenarios:

No tuning event shall last more than 18 consecutive hours.

The permittee shall record the time, date and duration of each tuning event. The records must include calculations of NO_x and CO emissions during each event based on the CEMS data. These records must be kept for five years following the date of such event.

If the applicable NOx and CO emission limits in Condition 1.a are exceeded during these events, the recorded emissions shall be included in the associated quarterly excess emission report.

The permittee shall notify the Piedmont Regional Office at least 24 hours prior to each declared turning event unless approval for a shorter notice is provided by DEQ. The notification shall include, but not be limited to, the following information:

Identification of the specific turbine to be tuned;

Reason for the declared tuning event; and

Measures that will be taken to minimize the duration of the declared turning event.

(9 VAC 5-20-180J and 9 VAC 5-50-20E)

<u>Auxiliary boilers (B-1, B-2) and fuel gas heaters (FGH-1, FGH-2, FGH-3)</u>

Emission Controls: Fuel Gas Heaters and Auxiliary Boilers – NO_x emissions from the auxiliary boilers (B-1, B-2) and fuel gas heaters (FGH-1, FGH-2, FGH-3) shall be controlled by low NO_x burners with a NO_x performance of 0.011 lbs/MMBtu. The low NO_x burners shall be installed and operated in accordance with manufacturer's specifications.
(9 VAC 5-50-280 and 9 VAC 5-80-1705 B)

Emission Controls: Fuel Gas Heaters and Auxiliary Boilers – CO and VOC emissions from the auxiliary boilers (B-1, B-2) and fuel gas heaters (FGH-1, FGH-2, FGH-3) shall be controlled by good combustion practices (controlled fuel/air, adequate temperature, and adequate gas residence time), operator training, and proper emissions unit design, construction and maintenance to achieve a maximum CO emission rate of 0.037 lb/MMBtu and a maximum VOC emission rate of 0.005 lb/MMBtu. Boiler and heater operators shall be trained in the proper operation of all such equipment. Training shall consist of a review and familiarization of the manufacturer's operating instructions, at a minimum. The permittee shall maintain records of the required training including a statement of time, place and nature of training provided. The permittee shall have available good written operating procedures and a maintenance schedule for the boilers and heater. These procedures shall be based on the manufacturer's recommendations and/or best engineering practices, at a minimum. All

records required by this condition shall be kept on site and made available for inspection by the DEQ.
(9 VAC 5-50-280 and 9 VAC 5-80-1705 B)

Emission Controls: Fuel Gas Heaters and Auxiliary Boilers – SO_2 and H_2SO_4 emissions from the auxiliary boilers (B-1, B-2) and fuel gas heaters (FGH-1, FGH-2, FGH-3) shall be controlled by the use of pipeline-quality natural gas with a maximum sulfur content of 0.4 grains per 100 standard cubic feet (scf), on a 12-month rolling average. Compliance will be based on fuel monitoring results as required by Condition 0 for the combustion turbine generators.
(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

Emission Controls: Fuel Gas Heaters and Auxiliary Boilers – PM, PM_{10}, and $PM_{2.5}$ emissions from the auxiliary boilers (B-1, B-2) and fuel gas heaters (FGH-1, FGH-2, FGH-3) shall be controlled by good combustion practices and the use of pipeline-quality natural gas with a maximum sulfur content of 0.4 grains per 100 scf, on a 12-month rolling average. Compliance will be based on fuel monitoring results as required by Condition 0.
(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

Emission Controls: Fuel Gas Heaters and Auxiliary Boilers – CO_2e emissions from the auxiliary boilers (B-1, B-2) and fuel gas heaters (FGH-1, FGH-2, FGH-3) shall be controlled by the use of natural gas fuel and high efficiency design and operation.
(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

<u>Emergency Units (EG-1 and FWP-1)</u>

Emission Controls: EG-1, FWP-1 – PM, PM_{10}, $PM_{2.5}$, NO_x, CO, SO_2, VOC, H_2SO_4, and CO_2e emissions from the diesel emergency units (EG-1 and FWP-1) shall be controlled by good combustion practices, high efficiency design, and the use of ultra-low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.
(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

Emission Controls: EG-1, FWP-1 – CO_2e emissions from the diesel emergency units (EG-1 and FWP-1) shall be controlled by the use of S15 ULSD and high efficiency design and operation.
(9 VAC 5-80-1705B and 9 VAC 5-50-280)

Monitoring Devices: EG-1 – The permittee must install a non-resettable hour meter on the emergency generator (EG-1) and the emergency fire water pump (FWP-1) prior to the startup of each unit. The hour meters shall be provided with adequate access for inspection.
(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

<u>Miscellaneous Processes</u>

Emission Controls: Equipment Leaks – Fugitive emissions from natural gas piping components (valves and flanges) located on the power plant property (NGL-1) shall be minimized by using best management practices to prevent, detect and repair leaks of natural gas from the piping components. At commencement of commercial operation, the permittee shall implement a daily auditory/visual/olfactory (AVO) inspection program for detecting

leaking in natural gas piping components. Records of the daily AVO inspection results, repair attempts, and repair results shall be maintained on site. The AVO plan shall be submitted for review no later than 60 days prior to commencement of commercial operation of the facility.
(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

Emission Controls: Electrical Breakers – The total combined capacity of the electrical circuit breakers shall not exceed 22,800 lbs of SF_6. Greenhouse gas emissions (including SF_6) from the circuit breakers (CB) shall be controlled by an enclosed-pressure circuit breaker, with a maximum annual leakage rate of 0.5 percent, and a low pressure detection system (with alarm). The low pressure detection system shall be in operation when the circuit breakers are in use. The permittee shall develop a maintenance plan for the circuit breakers that includes procedures for minimizing emissions and corrective action to be taken in the event of a low pressure alarm. The permittee shall keep records of the total quantity of SF_6 gas added to the circuit breakers in a calendar year.
(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

OPERATING LIMITATIONS

Fuel Throughput: Combustion Turbine Generators – Each of the three combustion turbine generators (CT-1, CT-2, CT-3) shall consume no more than a total of 3.5×10^{10} scf of natural gas per year, 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.
(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

Fuel Monitoring: Combustion Turbine Generators– The permittee shall determine the total sulfur content of the natural gas being fired at the electric power generation facility to verify that the sulfur content of the natural gas is less than or equal to 0.4 grains of total sulfur per 100 scf on a 12-month rolling average in order to demonstrate that potential sulfur dioxide and sulfuric acid mist emissions shall not exceed the limits specified in Condition 0 for the combustions turbine generators (CT-1, CT-2, CT-3). The permittee shall demonstrate compliance with the sulfur content limit in Condition 0 using one of the following:

Determine and record the total sulfur content of the natural gas each month. A monthly sample is not required for months when the turbines operated for 48 hours or less, or

Develop custom schedules for determination of the sulfur content of the natural gas based on the design and operation of the affected facility and the characteristics of the fuel supply. Except as provided in 40 CFR 60.4370(c)(1) and (c)(2), custom schedules shall be substantiated with data and shall receive prior EPA approval.

(9 VAC 5-50-410, 9 VAC 5-50-280, 40 CFR 60.4365(a), 40 CFR 60.4370(b), and 40 CFR 60.4370(c))

Alternate Operating Scenario Limitation: Combustion Turbine Generators –The total duration of turbine tuning events shall not exceed 96 hours per turbine per year, 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. (9 VAC 5-80-1705 B and 9 VAC 5-50-280)

Fuel: Combustion Turbine Generators, Fuel Gas Heaters, and Auxiliary boilers - The approved fuel for the combustion turbine generators (CT-1, CT-2, CT-3), fuel gas heaters (FGH-1, FGH-2, FGH-3), and the auxiliary boilers (B-1, B-2) is pipeline quality natural gas with a maximum sulfur content of 0.4 grains per 100 scf, on a 12-month rolling average basis. A change in the fuel may require a permit to modify and operate.
(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

Fuel Throughput: Auxiliary Boilers - Each of the two auxiliary boilers (B-1, B-2) shall consume no more than 7.21 x 10^8 scf of natural gas per year, 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.
(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

Fuel Throughput: Fuel Gas Heaters – Each of the fuel gas heaters (FGH-1, FGH-2, FGH-3) shall consume no more than 1.03 x 10^8 scf of natural gas per year, 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.
(9 VAC 5-80-1705B and 9 VAC 5-50-280)

Fuel: EG-1 and FWP-1 - The approved fuel for the emergency diesel fire water pump (FWP-1) and emergency diesel generator (EG-1) is ultra-low sulfur diesel (S15 ULSD). A change in the fuel may require a permit to modify and operate.
(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

Fuel: EG-1 and FWP-1- The fuel for the fire pump (FWP-1) and emergency generator (EG-1) shall meet the specifications below:

ULTRA-LOW SULFUR DIESEL FUEL (S15 ULSD) which meets the ASTM D975-10b specification for S15 fuel oil: Maximum sulfur content per shipment: 0.0015%

(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

Operating Hours: EG-1 and FWP-1 - The emergency generator (EG-1) and emergency fire water pump (FWP-1) shall not operate more than 500 hours each per year, 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.
(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

Emergency Operation: EG-1 and FWP-1 – The emergency diesel engine (EG-1) and firewater pump (FWP-1) shall only be operated in the following modes:

In situations that arises from sudden and reasonably unforeseeable events where the primary energy or power source is disrupted or disconnected due to conditions beyond the control of an owner or operator of a facility including:

A failure of the electrical grid;

On-site disaster or equipment failure; or

Public service emergencies such as flood, fire, natural disaster, or severe weather conditions.

For participation in an ISO-declared emergency, where an ISO emergency is:

An abnormal system condition requiring manual or automatic action to maintain system frequency, to prevent loss of firm load, equipment damage, or tripping of system elements that could adversely affect the reliability of an electric system or the safety of persons or property;

Capacity deficiency or capacity excess conditions;

A fuel shortage requiring departure from normal operating procedures in order to minimize the use of such scarce fuel;

Abnormal natural events or man-made threats that would require conservative operations to posture the system in a more reliable state; or

An abnormal event external to the ISO service territory that may require ISO action.

For periodic maintenance, testing, and operational training.

Total emissions for any 12 month period, calculated as the sum of all emissions from operations under the scenarios above, shall not exceed the annual limits (tons/yr) stated in Condition 0 for the firewater pump (FWP-1) and Condition 0 for the emergency generator (EG-1).
(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

Fuel Certification: EG-1 and FWP-1 - The permittee shall obtain a certification from the fuel supplier with each shipment of S15 ULSD oil. Each fuel supplier certification shall include the following:

The name of the fuel supplier;

The date on which the S15 ULSD oil was received;

The quantity of S15 ULSD oil delivered in the shipment;

A statement from the supplier that the fuel oil is S15 ULSD oil;

Fuel sampling and analysis, independent of that used for certification, as may be periodically required or conducted by DEQ may be used to determine compliance with the fuel specifications stipulated in Condition 0. Exceedance of these specifications may be considered credible evidence of the exceedance of emission limits.
(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

Maintenance and Operation: EG-1 and FWP-1 – The permittee must maintain and operate the emergency fire pump (FWP-1) and emergency generator (EG-1) according to the

manufacturer's recommendations and/or procedures developed by the permittee using best engineering practices, over the entire life of the engine.
(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

Requirements by Reference: NSPS - Except where this permit is more restrictive than the applicable requirement, the NSPS equipment as described in the equipment table in the Introduction on page 2 of this permit shall be operated in compliance with the requirements of 40 CFR 60, Subparts Dc, IIII, and KKKK.
(9 VAC 5-50-400 and 9 VAC 5-50-410)

EMISSION LIMITS

Short-Term Emission Limits: Combustion Turbine Generators -Emissions from the operation of each combustion turbine generator (CT-1, CT-2, CT-3), shall not exceed the limits specified below:

Normal operation – The limits in the table below apply as described in the "Applicability" column. Periods considered startup and shutdown are defined in Condition 0 of this permit, and alternate operating scenarios are defined in Condition 0.

Pollutant	Short term emission limits	Applicability
PM $_{\text{filterable only}}$	0.0052 lb/MMBtu	This limit applies at all times except during tuning. See item a below.
PM_{10}	0.0052 lb/MMBtu 12.3 lb/hr as an average of three test runs.	These limits apply at all times except during tuning. See item **Error! Reference source not found.** below.
$PM_{2.5}$	0.0052 lb/MMBtu 12.3 lb/hr as an average of three test runs	These limits apply at all times except during tuning. See item a below.
SO_2	0.00114 lb/MMBtu	This limit applies at all times.
NO_x	2.0 ppmvd @ 15% O_2 as a one-hour average	This limit applies at all times except during startup, shutdown, and tuning. See items **Error! Reference source not found.** and c below.
CO	1.0 ppmvd @ 15% O_2	This limit applies at all times except during startup, shutdown, and tuning. See items a and c below.
VOC	0.7 ppmvd @ 15% O_2	This limit applies at all times except during startup, shutdown, and tuning. See items a and c below.
H_2SO_4	0.0012 lb/MMBtu	This limit applies at all times.

Where:
ppmvd = parts per million by volume on a dry gas basis, corrected to 15 percent O_2.

Short-term emission limits represent averages for a three-hour sampling period for CO, VOC, SO_2 and H_2SO_4. Nitrogen oxides shall be calculated as a one-hour average. PM, PM_{10} and $PM_{2.5}$ limits represent the average of three test runs.

These emissions are derived from the estimated overall emission contribution from operating limits. Exceedance of the operating limits may be considered credible evidence of the exceedance of emission limits. Compliance with these limits may be determined as stated in Conditions 0, 0, 0, 0, 0, 0, 0, 0, 0, 0, and 0.

a. During each CT tuning event as described in Condition 0, emissions shall not exceed the following limits:

Pollutant	Limitations for Tuning Events
NO_x	703 lb/turbine/calendar day
CO	214 lb/turbine/calendar day
VOC	Duration of tuning events shall not exceed limits in Condition 0.
PM, PM_{10}, $PM_{2.5}$	Duration of tuning events shall not exceed limits in Condition 0.

The emissions limits for tuning events do not include emissions from startup and/or shutdown that may occur on the same calendar day.

b. NO_x emission concentrations shall not exceed the NO_x standards of the NSPS Subpart KKKK of 15 ppm at loads > 75% or 96 ppm at loads ≤ 75% corrected to 15% O_2 (on a rolling 30-day average basis).

c. During each startup or shutdown event, emissions shall not exceed the following:

Pollutant	Startup/Shutdown Limitations
NO_x	cold start event – 60 lb/turbine/event warm start event – 54 lb/turbine/event hot start event – 42 lb/turbine/event shutdown event – 20 lb/turbine/event
CO	cold start event – 444 lb/turbine/event warm start event – 396 lb/turbine/event hot start event – 252 lb/turbine/event shutdown event – 156 lb/turbine/event
VOC	cold start event – 216 lb/turbine/event warm start event – 216 lb/turbine/event hot start event – 168 lb/turbine/event shutdown event – 216 lb/turbine/event

These emissions are derived from the estimated overall emission contribution from operating limits. Exceedance of the operating limits may be considered credible evidence of the exceedance of emission limits. Compliance with the NOx and CO limits may be determined as stated in Conditions 0 and 0. Compliance with the VOC limits may be determined by demonstrating correlation of VOC emissions to CO emissions, using CO and VOC stack testing and CO CEM data.

(9 VAC 5-50-280, 9 VAC 5-80-1705, 9 VAC 5-80-1715)

Emission Limits: Combustion Turbine Generators – CO_2e emissions from each of the combustion turbine generators (CT-1, CT-2, CT-3) and the steam turbines, providing for incremental degradation of the units, shall not exceed the following:

Degradation Period	Applicable limit in lb CO_{2e}/MWh net output
Years 1-6	812
Years 7-12	824
Years 13-18	836
Years 19-24	847
Years 25-30	859
Years 31 and later	871

For the purposes of determining which limit is applicable, Year 1 begins upon commencement of commercial operation and ends on December 31 of the first full calendar year after that date. Each limit increments on January 1 of the respective year. For example, if the facility commences commercial operation on April 15, 2021, Year 1 begins on April 15, 2021 and ends on December 31, 2022. Year 7 begins, and the increased limit becomes effective, on January 1, 2028.

Compliance with the applicable limit shall be calculated monthly on a 12- month rolling basis. Compliance may be determined each month by summing the calculated CO_2e emissions from the combustion turbine generators (CT-1, CT-2, CT-3) during the previous 12 months (Condition 0) and dividing that value by the sum of the electrical energy output over that same period (Condition 0).
(9 VAC 5-50-280, 9 VAC 5-80-1705, and 9 VAC 5-80-1715)

Annual Process Emission Limits: Combustion Turbine Generators – Emissions from the operation of each of the three combustion turbine generators (CT-1, CT-2, CT-3) shall not exceed the limits specified below:

PM	53.9	tons/yr (on a 12-month, rolling total)
PM_{10}	53.9	tons/yr (on a 12-month, rolling total)
$PM_{2.5}$	53.9	tons/yr (on a 12-month, rolling total)
SO_2	20.4	tons/yr (on a 12-month, rolling total)
NO_x	128.4	tons/yr (on a 12-month, rolling total)
CO	94.3	tons/yr (on a 12-month, rolling total)
VOC	68.1	tons/yr (on a 12-month, rolling total)
H_2SO_4	21.4	tons/yr (on a 12-month, rolling total)
CO_2e	2,123,519	tons/yr (on a 12-month, rolling total)

These emissions are derived from the estimated overall emission contribution from operating limits, and include periods of startup and shutdown, and tuning. Exceedance of the operating limits may be considered credible evidence of the exceedance of emission limits. Compliance with these emission limits may be determined as stated in Conditions 0, 0, 0, 0, 0, 0, 0, 0, 0, and 0.
(9 VAC 5-50-280, 9 VAC 5-80-1705, and 9 VAC 5-80-1715)

Process Emission Limits: Auxiliary Boilers – Emissions from the operation of each of the auxiliary boilers (B-1, B-2) shall not exceed the limits specified below:

PM	0.6	lbs/hr	2.6	tons/yr (on a 12-month, rolling total)
PM_{10}	0.6	lbs/hr	2.6	tons/yr (on a 12-month, rolling total)
$PM_{2.5}$	0.6	lbs/hr	2.6	tons/yr (on a 12-month, rolling total)
SO_2	0.00114	lb/MMBtu	0.5	tons/yr (on a 12-month, rolling total)
NO_x	1.0	lbs/hr	4.1	tons/yr (on a 12-month, rolling total)
CO	3.2	lbs/hr	13.7	tons/yr (on a 12-month, rolling total)
VOC	0.005	lbs/MMBtu	1.9	tons/yr (on a 12-month, rolling total)
CO_2e			43,827	tons/yr (on a 12-month, rolling total)

These emissions are derived from the estimated overall emission contribution from operating limits, including periods of startup and shutdown. Exceedance of the operating limits may be considered credible evidence of the exceedance of emission limits. Compliance with these emission limits may be determined as stated in Conditions 0, 0, 0, 0, 0, 0, 0, 0, 0, and 0.
(9 VAC 5-50-280, 9 VAC 5-80-1705, and 9 VAC 5-80-1715)

Process Emission Limits: Electrical Breakers - Emissions from the operation of the electrical circuit breakers (CB-1) shall not exceed 1,140 tons of CO_2e/year on a 12 month, rolling average. These emissions are derived from the estimated overall emission contribution from operating limits. Exceedance of the operating limits may be considered credible evidence of the exceedance of emission limits. Compliance with these emission limits may be determined as stated in Condition 0.
(9 VAC 5-50-280, 9 VAC 5-80-1705, and 9 VAC 5-80-1715)

Process Emission Limits: FWP-1 - Emissions from the operation of the fire water pump (FWP-1) shall not exceed the limits specified below:

PM	0.15	g/hp-hr		
PM_{10}	0.15	g/hp-hr		
$PM_{2.5}$	0.15	g/hp-hr		
NO_x	3.0	g/hp-hr	0.7	tons/yr (on a 12-month rolling total)
CO	2.6	g/hp-hr	0.6	tons/yr (on a 12-month rolling total)
VOC	0.11	g/hp-hr		
SO_2	0.00154	lb/MMBtu		
H_2SO_4	0.000118	lb/MMBtu		
CO_2e			106	tons/yr (on a 12-month rolling total)

These emissions are derived from the estimated overall emission contribution from operating limits. Exceedance of the operating limits may be considered credible evidence of the exceedance of emission limits. Compliance with these emission limits may be determined as stated in Conditions 0, 0, 0, 0, 0 and 0.
(9 VAC 5-50-280, 9 VAC 5-80-1705, and 9 VAC 5-80-1715)

Process Emission Limits: EG-1 - Emissions from the operation of the diesel emergency generator (EG-1) shall not exceed the limits specified below:

PM	0.15	g/hp-hr		
PM_{10}	0.15	g/hp-hr		
$PM_{2.5}$	0.15	g/hp-hr		
NO_x	4.8	g/hp-hr	11.7	tons/yr (on a 12-month rolling total)
CO	2.6	g/hp-hr	6.4	tons/yr (on a 12-month rolling total)
VOC	1.0	g/hp-hr		
SO_2	0.00154	lb/MMBtu		
H_2SO_4	0.000118	lb/MMBtu		
CO_2e			1,203	tons/yr (on a 12-month rolling total)

These emissions are derived from the estimated overall emission contribution from operating limits. Exceedance of the operating limits may be considered credible evidence of the exceedance of emission limits. Compliance with these emission limits may be determined as stated in Conditions 0, 0, 0, 0, 0, and 0.
(9 VAC 5-50-280, 9 VAC 5-80-1705, and 9 VAC 5-80-1715)

Process Emission Limits: Fuel Gas Heaters – Emissions from the operation of each of the fuel gas heaters (FGH-1, FGH-2, FGH-3) shall not exceed the limits specified below:

PM		0.4	tons/yr (on a 12-month rolling total)
PM_{10}		0.4	tons/yr (on a 12-month rolling total)
$PM_{2.5}$		0.4	tons/yr (on a 12-month rolling total)
NO_x		0.6	tons/yr (on a 12-month rolling total)
CO	0.5 lb/hr	2.0	tons/yr (on a 12-month rolling total)
VOC		0.3	tons/yr (on a 12-month rolling total)
CO_2e		6,261	tons/yr (on a 12-month rolling total)

These emissions are derived from the estimated overall emission contribution from operating limits, including periods of startup and shutdown. Exceedance of the operating limits may be considered credible evidence of the exceedance of emission limits. Compliance with these emission limits may be determined as stated in Conditions 0, 0, 0, 0, 0, 0, 0, 0, 0, and 0.
(9 VAC 5-50-280, 9 VAC 5-80-1705, and 9 VAC 5-80-1715)

Visible Emission Limit: Combustion Turbine Generators - Visible emissions from the combustion turbine generators (CT-1, CT-2, CT-3) shall not exceed 10 percent opacity except during one six-minute period in any one hour in which visible emissions shall not exceed 20 percent opacity as determined by the EPA Method 9 (reference 40 CFR 60, Appendix A).
(9 VAC 5-50-80 and 9 VAC 5-50-280)

Visible Emission Limit: Fuel Gas Heaters and Auxiliary Boilers - Visible emissions from the fuel gas heaters (FGH-1, FGH-2, FGH-3) and auxiliary boilers (B-1, B-2) shall not exceed 10 percent opacity as determined by the EPA Method 9 (reference 40 CFR 60, Appendix A).
(9 VAC 5-50-80 and 9 VAC 5-50-280)

Visible Emission Limit: EG-1 and FWP-1 - Visible emissions from the emergency fire water pump (FWP-1) and diesel emergency generator (EG-1) shall not exceed 10 percent opacity as determined by the EPA Method 9 (reference 40 CFR 60, Appendix A).
(9 VAC 5-50-80 and 9 VAC 5-50-280)

CONTINUOUS MONITORING SYSTEMS

CEMS: Combustion Turbine Generators - Continuous Emission Monitoring Systems (CEMS) shall be installed to measure and record the emissions of NO_x (measured as NO_2) and CO from each combustion turbine generator (CT-1, CT-2, CT-3) in ppmvd, corrected to 15 percent O_2. CEMS for NO_x shall meet the design specifications of 40 CFR Part 75 whereas CEMS for CO shall be installed, evaluated, and operated according to the monitoring requirements in 40 CFR 60.13. The CEMS shall also measure and record the oxygen content of the flue gas at each location where NO_x and CO emissions are monitored and measure heat input and power output. A CEMS or alternative method as allowed by 40 CFR 75.11 (d) and (e) shall be used to measure sulfur dioxide emissions to comply with the requirements of 40 CFR 75 (acid rain program monitoring). For compliance with the emission limits contained in Condition 0, NO_x data shall be reduced to 1-hour block averages. CO data shall be reduced to 3-hour rolling averages.
(9 VAC 5-50-350 and 9 VAC 5-50-40)

CEMS Performance Evaluations - Performance evaluations of the NO_x and, if applicable, SO_2 CEMS shall be conducted in accordance with 40 CFR Part 75, Appendix A, and shall take place during the performance tests under 9 VAC 5-50-30 or within 30 days thereafter. Two copies of the performance evaluations report shall be submitted to the Piedmont Region within 45 days of the evaluation. The continuous monitoring systems shall be installed and operational prior to conducting initial performance tests. Verification of operational status shall, as a minimum, include completion of the manufacturer's written requirements or recommendations for installation, operation and calibration of the device. A 30 day notification, prior to the demonstration of continuous monitoring system's performance, and subsequent notifications shall be submitted to the Piedmont Region.
(9 VAC 5-50-350 and 9 VAC 5-50-40)

Continuous Monitoring: Combustion Turbine Generators – Greenhouse gases – CO_2 emissions from each combustion turbine generator (CT-1, CT-2, CT-3) shall be monitored using one of the methods in 40 CFR Part 75.13. The permittee shall notify the Piedmont Regional Office as to which method was used to determine the emissions of CO_2 from the turbines. The methods in Appendix G to 40 CFR Part 75, shall be used to report annual CO_2 emissions. CH_4 and N_2O emissions shall be calculated using fuel heat value data and the emission factors found in 40 CFR Part 98, Subpart C, Table C-2. Annual CO_2e emissions shall be calculated using the global warming potential factors found in 40 CFR Part 98, Subpart A, Table A-1 for CO_2, CH_4 and N_2O.

(9 VAC 5-50-50)

Continuous Monitoring: Net Power Output and Fuel Flow – The permittee shall continuously monitor the net electrical output of each combustion turbine generator and associated steam turbine (CT-1, CT-2, CT-3), measured at the generator terminals, and the fuel flow to each combustion turbine generator to show compliance with the applicable emission limitation in Condition 0 on a 12-operating month rolling basis.
(9 VAC 5-50-40F)

Continuous Monitoring Quality Control Program - A CMS quality control program which is equivalent to the requirements of 40 CFR 75 Appendix B shall be implemented for all continuous monitoring systems.
(9 VAC 5-50-350 and 9 VAC 5-50-40)

CEMS Emissions Data – For the purposes of this permit and DEQ's emissions inventory, CEMS data shall be used to report annual emissions of NO_x and CO from the stack of each combustion turbine generator (CT-1, CT-2, CT-3) in tons/yr.
(9 VAC 5-50-50)

CEMS: Excess Emissions and Monitor Downtime for NO_x and CO - For the purpose of this permit, periods of excess emissions and monitor downtime that must be reported under Condition 0 are defined as follows:

a. An excess emission period is an operating period in which the NO_x emission rate exceeds the applicable emission limits in Condition 0, a, b, or c;

b. An excess emission period is an operating period in which the CO emission rate exceeds the applicable emission limits in Condition 0, a, or c; and

c. A period of monitor downtime is any unit operating hour in which the data for any of the following parameters are either missing or invalid: NO_x concentration, CO concentration, O_2 concentration, fuel flow rate, steam pressure, or megawatts. The steam flow rate is only required if the permittee uses this information for compliance purposes.

(9 VAC 5-50-50, 9 VAC 5-50-410, 40 CFR 60.7(c), and 40 CFR 60.4380)

Continuous Monitoring Systems: Excess Emissions and Monitor Downtime for SO_2 -Excess emissions and monitoring downtime are defined, for the purpose of this permit, as follows:

a. Excess emissions of SO_2 from the combustion turbine generators occurs when the 12-month rolling average sulfur content of the fuel being fired in the combustion turbine generators (CT-1, CT-2, CT-3) exceeds the applicable limit in Condition 0 based on monthly fuel testing in Condition 0. The excess emission period ends on the date that 12-month rolling average sulfur content of the fuel demonstrates compliance with the sulfur limit; and

b. A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date of a required sample, if invalid results are obtained. The period of monitor downtime ends on the date of the next valid sample.

(9 VAC 5-50-50, 9 VAC 5-50-280)

Continuous Monitoring Excess Emissions Reports - The permittee shall furnish written reports to the Piedmont Region of excess emissions from any process monitored by a continuous monitoring system on a quarterly basis, postmarked no later than the 30th day following the end of the calendar quarter. These reports shall include, but are not limited to the following information:

The magnitude of excess emissions, any conversion factors used in the calculation of excess emissions, and the date and time of commencement and completion of each period of excess emissions;

Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the process, the nature and cause of the malfunction (if known), the corrective action taken or preventative measures adopted;

The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments; and

When no excess emissions have occurred or the continuous monitoring systems have not been inoperative, repaired or adjusted, such information shall be stated in that report.

Excess emission reports for sulfur dioxide and nitrogen dioxide as required in 40 CFR 60.4395.
(9 VAC 5-50-50)

CEMS: Excess Emissions – For purposes of identifying excess emissions:

All CEMS data must be reduced to hourly averages as specified in 40 CFR 60.13(h);

For each operating hour in which a valid hourly average, as described in 40 CFR 60.4345(b), is obtained for both NO_x and diluent monitors, the data acquisition and handling system must calculate and record the hourly NO_x emission rate in units of ppm, using the appropriate equation in 40 CFR Part 60, Appendix A, Method 19. For any hour in which the hourly average O_2 concentration exceeds 19.0 percent O_2, a diluent cap value of 19.0 percent O_2 may be used in the emission calculations; and

Only quality assured data from the CEMS shall be used to identify excess emissions. Periods where the missing data substitution procedures in 40 CFR 75, Appendix D are applied are to be reported as monitor downtime in the excess emissions and monitoring performance report required under 40 CFR 60.7(c).
(9 VAC 5-50-50, 9 VAC 5-50-410, 40 CFR 60.7(c), and 40 CFR 60.4350)

INITIAL COMPLIANCE DETERMINATION

Emissions Testing: Facility - The permitted facility shall be constructed so as to allow for emissions testing upon reasonable notice at any time, using appropriate methods. This includes constructing the facility/equipment such that volumetric flow rates and pollutant emission rates can be accurately determined by applicable test methods and providing a stack or duct that is free from excessive cyclonic flow as defined in 40 CFR 60 Appendix A. Sampling ports shall be provided at the appropriate locations (in accordance with the

applicable performance specification in 40 CFR Part 60, Appendix B) and safe sampling platforms and access shall be provided.
(9 VAC 5-50-30 F and 9 VAC 5-80-1675)

Initial Performance Test: Combustion Turbine Generators - Initial performance tests shall be conducted for CO, PM, PM_{10}, $PM_{2.5}$, and total VOC from each combustion turbine generator (CT-1, CT-2, CT-3) to determine compliance with the emission limits contained in Condition 0. The tests shall be performed and demonstrate compliance within 60 days after achieving the maximum production rate at which the facility will be operated but in no event later than 180 days after start-up of the permitted facility. Tests shall be conducted and reported and data reduced as set forth in 9 VAC 5-50-30 and the test methods and procedures contained in each applicable section or subpart listed in 9 VAC 5-50-410. Tests shall be conducted at full load. The details of the tests are to be arranged with the Piedmont Regional Office. The permittee shall submit a test protocol at least 30 days prior to testing. One copy of the test results shall be submitted to the Piedmont Regional Office within 60 days of test completion and shall conform to the test report format enclosed with this permit.
(9 VAC 5-50-30, 9 VAC 5-80-1675, and 9 VAC 5-50-410)

Initial Performance Test: Combustion Turbine Generators – Initial performance tests shall be conducted on each combustion turbine generator (CT-1, CT-2, CT-3) for NO_x (as NO_2) to determine compliance with the limits contained in Condition 0 using 40 CFR 60, Appendix A, Methods 7E or 20 to measure the NO_x concentration (in ppm) and following the performance test specifications found in 40 CFR 60.4400.The tests shall be performed, reported, and demonstrate compliance within 60 days after achieving the maximum production rate at which the unit will be operated but in no event later than 180 days after start-up of the permitted unit. Tests shall be conducted and reported and data reduced as set forth in 9 VAC 5-50-30 and the test methods and procedures contained in each applicable section or subpart listed in 9 VAC 5-50-410. The details of the tests are to be arranged with the Piedmont Regional Office. The permittee shall submit a test protocol at least 30 days prior to testing. One copy of the test results shall be submitted to the Piedmont Regional Office, within 60 days after test completion and shall conform to the test report format enclosed with this permit.
(9 VAC 5-50-30, 9 VAC 5-50-410, and 9 VAC 5-80-1675)

Initial Performance Test: Combustion Turbine Generators – Initial performance tests shall be conducted on each combustion turbine generator (CT-1, CT-2, CT-3) for SO_2 to determine compliance with the limits contained in Condition 0. The permittee may use one of the following three methods (0., 0. or 0. below) to conduct the performance test:

If the permittee chooses to periodically determine the sulfur content of the fuel combusted in the turbine, a representative fuel sample would be collected following ASTM D5287 (incorporated by reference, see 40 CFR 60.17 or by manually sampling using Gas Process Association Standard 2166) for natural gas. The fuel analyses may be performed either by the permittee, a service contractor retained by the permittee, the fuel vendor, or any other qualified agency. The samples for the total sulfur content of the fuel shall be analyzed using ASTM D1072, or alternatively D3246, D4084, D4468, D4810, D6228, D6667, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see 40 CFR 60.17).

40 CFR 60, Appendix A, Methods 6, 6C, 8, or 20 shall be used to measure the SO_2 concentration (in parts per million (ppm)). In addition, the American Society of Mechanical Engineers (ASME) standard, ASME PTC 9–10–1981–Part 10, "Flue and Exhaust Gas Analyses," manual methods for sulfur dioxide (incorporated by reference, see 40 CFR 60.17) can be used instead of EPA Methods 6 or 20.

40 CFR 60, Appendix A, Methods 6, 6C, or 8 and 3A, or 20 shall be used to measure the SO_2 and diluent gas concentrations. In addition, the permittee may use the manual methods for sulfur dioxide ASME PTC 19–10–1981–Part 10 (incorporated by reference, see 40 CFR 60.17).

The tests shall be performed, reported, and demonstrate compliance within 60 days after achieving the maximum production rate at which the unit will be operated but in no event later than 180 days after start-up of the permitted unit. Tests shall be conducted and reported and data reduced as set forth in 9 VAC 5-50-30 and the test methods and procedures contained in each applicable section or subpart listed in 9 VAC 5-50-410. The details of the tests are to be arranged with the Piedmont Regional Office. The permittee shall submit a test protocol at least 30 days prior to testing. One copy of the test results shall be submitted to the Piedmont Regional Office, within 60 days after test completion and shall conform to the test report format enclosed with this permit. If fuel sampling is used, as described in 0 above, no test protocol or test report is required, however the permittee shall notify the Piedmont Regional Office as to which method was used to determine the total sulfur content of the fuel sample.
(9 VAC 5-50-30, 9 VAC 5-50-410 and 9 VAC 5-80-1675)

Initial Performance Test: Auxiliary Boilers and Fuel Gas Heaters - Initial performance tests shall be conducted for NOx and CO from the auxiliary boilers (B-1, B-2) and the fuel gas heaters (FGH-1, FGH-2, FGH-3) to determine compliance with the emission limits contained in Conditions 0 and 0, as applicable. The tests shall be performed, reported and demonstrate compliance within 60 days after the boilers or fuel gas heater, as applicable, reach the maximum load level at which the unit will be operated but in no event later than 180 days after its initial start-up. Tests shall be conducted and reported and data reduced as set forth in 9 VAC 5-50-30 and the test methods and procedures contained in each applicable section or subpart listed in 9 VAC 5-50-410. The details of the tests are to be arranged with the Piedmont Regional Office. The permittee shall submit a test protocol at least 30 days prior to testing. One copy of the test results shall be submitted to the Piedmont Regional Office within 60 days of test completion and shall conform to the test report format enclosed with this permit.
(9 VAC 5-50-30, 9 VAC 5-80-1985 E, and 9 VAC 5-50-410)

Visible Emissions Evaluation: Combustion Turbine Generators - Concurrently with the initial performance tests, Visible Emission Evaluations (VEE) in accordance with 40 CFR Part 60, Appendix A, Method 9, shall be conducted by the permittee on each combustion turbine generator (CT-1, CT-2, CT-3). Each test shall consist of 30 sets of 24 consecutive observations (at 15 second intervals) to yield a six-minute average. The VEE shall be conducted at full load. The details of the tests are to be arranged with the Piedmont Regional Office. The permittee shall submit a test protocol at least 30 days prior to testing. The evaluation shall be performed, reported, and demonstrate compliance within 60 days after

achieving the maximum production rate at which the unit will be operated but in no event later than 180 days after start-up of the permitted unit. Should conditions prevent concurrent opacity observations, the Piedmont Regional Office shall be notified in writing, within seven days, and visible emissions testing shall be rescheduled within 30 days. Rescheduled testing shall be conducted under the same conditions (as possible) as the initial performance tests. One copy of the test result shall be submitted to the Piedmont Regional Office within 60 days after test completion and shall conform to the test report format enclosed with this permit.
(9 VAC 5-50-30 and 9 VAC 5-80-1675)

Visible Emissions Evaluation: Auxiliary Boilers and Fuel Gas Heaters - Concurrently with the initial performance tests required in Condition 0, Visible Emission Evaluations (VEE) in accordance with 40 CFR Part 60, Appendix A, Method 9, shall be conducted by the permittee on each of the auxiliary boilers (B-1, B-2) and fuel gas heaters (FGH-1, FGH-2, FGH-3). Each test shall consist of 10 sets of 24 consecutive observations (at 15 second intervals) to yield a six-minute average. The details of the tests are to be arranged with the Piedmont Regional Office. The permittee shall submit a test protocol at least 30 days prior to testing. The evaluation shall be performed, reported, and demonstrate compliance within 60 days after achieving the maximum production rate at which the boilers will be operated but in no event later than 180 days after start-up of the boiler. Should conditions prevent concurrent opacity observations, the Piedmont Regional Office shall be notified in writing, within seven days, and visible emissions testing shall be rescheduled within 30 days. Rescheduled testing shall be conducted under the same conditions (as possible) as the initial performance tests. One copy of the test result shall be submitted to the Piedmont Regional Office within 60 days after test completion and shall conform to the test report format enclosed with this permit.
(9 VAC 5-50-30 and 9 VAC 5-80-1675)

Testing: Power Block Heat Rate - Initial compliance testing, using ASME Performance Test Code on Overall Plant Performance (ASME PTC 46-1996) or equivalent method approved by the Piedmont Regional Office, shall be conducted for the heat rate of the power blocks (i.e., a combination of CT-1, CT-2, CT-3 and the steam turbine generators) to show compliance with the initial limit contained in Condition 0. The testing shall be performed, reported and demonstrate compliance within 90 days after achieving the maximum production rate at which the facility will be operated but in no event later than 180 days after commencement of commercial operation of the permitted facility. The details of the tests are to be arranged with the Piedmont Regional Office. The permittee shall submit a test protocol at least 30 days prior to testing. One copy of the test results shall be submitted to the Piedmont Regional Office within 60 days of test completion and shall conform to the test report format enclosed with this permit.
(9 VAC 5-50-30 and 9 VAC 5-80-1675)

CONTINUING COMPLIANCE DETERMINATION

Continuing Compliance: Combustion Turbine Generators – The permittee shall conduct additional performance tests for VOC, PM_{10} and $PM_{2.5}$ from the combustion turbine generators (CT-1, CT-2, CT-3) to demonstrate compliance with the emission limits contained in this permit every five years. The tests shall occur no less than 54 months and no more

than 66 months after the previous test. The details of the tests shall be arranged with the Piedmont Regional Office.
(9 VAC 5-50-30 and 9 VAC 5-80-1675)

Annual Performance Test: Combustion Turbine Generators – Annual performance tests shall be conducted on each combustion turbine generator (CT-1, CT-2, CT-3) for SO_2 to determine compliance with the limits contained in Condition 0. The permittee may use one of the following three methods (0., 0. or 0. below) to conduct the performance test:

If the permittee chooses to periodically determine the sulfur content of the fuel combusted in the turbine, a representative fuel sample would be collected following ASTM D5287 (incorporated by reference, see 40 CFR 60.17 or by manual sampling using the Gas Process Association Standard 2166) for natural gas. The fuel analyses may be performed either by the permittee, a service contractor retained by the permittee, the fuel vendor, or any other qualified agency. The samples for the total sulfur content of the fuel shall be analyzed using ASTM D1072, or alternatively D3246, D4084, D4468, D4810, D5504, D6228, D6667, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see 40 CFR 60.17).

40 CFR 60, Appendix A, Methods 6, 6C, 8, or 20 shall be used to measure the SO_2 concentration (in parts per million (ppm)). In addition, the American Society of Mechanical Engineers (ASME) standard, ASME PTC 9–10–1981–Part 10, “Flue and Exhaust Gas Analyses,” manual methods for sulfur dioxide (incorporated by reference, see 40 CFR 60.17) can be used instead of EPA Methods 6 or 20.

40 CFR 60, Appendix A, Methods 6, 6C, or 8 and 3A, or 20 shall be used to measure the SO_2 and diluent gas concentrations. In addition, the permittee may use the manual methods for sulfur dioxide ASME PTC 19–10–1981–Part 10 (incorporated by reference, see 40 CFR 60.17).

The tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test). Tests shall be conducted and reported and data reduced as set forth in 9 VAC 5-50-30 and the test methods and procedures contained in each applicable section or subpart listed in 9 VAC 5-50-410. The details of the tests are to be arranged with the Piedmont Regional Office. The permittee shall submit a test protocol at least 30 days prior to testing. One copy of the test results shall be submitted to the Piedmont Regional Office, within 60 days after test completion and shall conform to the test report format enclosed with this permit. If fuel sampling is used, as described in 0 above, no test protocol or test report is required, however the permittee shall notify the Piedmont Regional Office as to which method was used to determine the total sulfur content of the fuel sample.
(9 VAC 5-50-30, 9 VAC 5-50-410)

Periodic Testing: Power Block Heat Rate–The permittee shall conduct subsequent heat rate testing of the power blocks in accordance with Condition 0 to show compliance with the applicable heat rate contained in Condition 0 in Years 6, 12, 18, 24 and 30. After Year 30, additional tests shall be conducted between 60 and 73 months after the previous test. The details of the evaluation are to be arranged with the Piedmont Regional Office.
(9 VAC 5-50-30 and 9 VAC 5-80-1675)

Stack Tests: Continuing Compliance – Upon request by DEQ, the permittee shall conduct additional performance tests to determine compliance with the emission limits contained in this permit. The details of the tests shall be arranged with the Piedmont Regional Office. (9 VAC 5-50-30 G)

RECORDS

On Site Records: Facility - The permittee shall maintain records of emission data and operating parameters as necessary to demonstrate compliance with this permit. The content and format of such records shall be arranged with the Piedmont Region. These records shall include, but are not limited to:

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

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

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

Monthly and annual throughput of natural gas to each of the auxiliary boilers (B-1, B-2) and fuel gas heaters (FGH-1, FGH-2, FGH-3), calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months;

Fuel sulfur monitoring records for the natural gas combusted in the combustion turbine generators (CT-1, CT-2, CT-3), auxiliary boilers (B-1, B-2), and fuel gas heaters (FGH-1, FGH-2, FGH-3);

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

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

Operation and control device monitoring records for each SCR system and oxidation catalyst as required in Conditions 0 and 0;

Records of alternative operating scenarios as required by Conditions 0, 0, and 0;

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;

Results of daily AVO inspections for fugitive natural gas leak detection from the piping and components, including any repairs or other records required by Condition 0.

Scheduled and unscheduled maintenance, and operator training.

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

Manufacturer's instructions for proper operation of equipment.

Records showing the circuit breakers are operating in accordance with the manufacturer's specifications (see Condition 0).

These records shall be available for inspection by the DEQ and shall be current for the most recent five years.
(9 VAC 5-50-50 and 9 VAC 5-50-410)

NOTIFICATIONS

Initial Notifications - The permittee shall furnish written notification to the Piedmont Regional Office of:

The actual date on which construction of the electric power generation facility commenced within 30 days after such date.

The anticipated start-up date of the electric power generation facility postmarked not more than 60 days nor less than 30 days prior to such date.

The actual start-up date of the electric power generation facility within 15 days after such date.

The anticipated date of continuous monitoring system performance evaluations postmarked not less than 30 days prior to such date.

The anticipated date of performance tests of the combustion turbine generators (CT-1, CT-2, CT-3), auxiliary boilers (B-1, B-2), and the fuel gas heaters (FGH-1, FGH-2, FGH-3), postmarked at least 30 days prior to such date.

Copies of the written notification referenced in items 0 through 0 above are to be sent to:
Associate Director
Office of Air Enforcement and Compliance Assistance (3AP20)
U.S. Environmental Protection Agency
Region III
1650 Arch Street
Philadelphia, PA 19103-2029

(9 VAC 5-50-50 and 9 VAC 5-50-410)

GENERAL CONDITIONS

Permit Invalidation –This permit to construct the electric power generation facility shall become invalid, unless an extension is granted by the DEQ, if:

A program of continuous construction or modification is not commenced within 18 months from the date of this permit.

A program of construction or modification is discontinued for a period of 18 months or more, or is not completed within a reasonable time, except for a DEQ approved period between phases of the phased construction of a new stationary source or project.
(9 VAC 5-80-1985)

Permit Suspension/Revocation - This permit may be suspended or revoked if the permittee:

Knowingly makes material misstatements in the permit application or any amendments to it;

Fails to comply with the conditions of this permit;

Fails to comply with any emission standards applicable to a permitted emissions unit;

Causes emissions from the stationary source which result in violations of, or interfere with the attainment and maintenance of, any ambient air quality standard; or

Fails to operate in conformance with any applicable control strategy, including any emission standards or emission limitations, in the State Implementation Plan in effect at the time an application for this permit is submitted.
(9 VAC 5-80-1985 F)

Right of Entry - The permittee shall allow authorized local, state, and federal representatives, upon the presentation of credentials:

To enter upon the permittee's premises on which the facility is located or in which any records are required to be kept under the terms and conditions of this permit;

To have access to and copy at reasonable times any records required to be kept under the terms and conditions of this permit or the State Air Pollution Control Board Regulations;

To inspect at reasonable times any facility, equipment, or process subject to the terms and conditions of this permit or the State Air Pollution Control Board Regulations; and

To sample or test at reasonable times.

For purposes of this condition, the time for inspection shall be deemed reasonable during regular business hours or whenever the facility is in operation. Nothing contained herein shall make an inspection time unreasonable during an emergency.
(9 VAC 5-170-130 and 9 VAC 5-80-1180)

Maintenance/Operating Procedures – At all times, including periods of start-up, shutdown, and malfunction, the permittee shall, to the extent practicable, maintain and operate the affected source, including associated air pollution control equipment, in a manner consistent with good air pollution control practices for minimizing emissions.

The permittee shall take the following measures in order to minimize the duration and frequency of excess emissions, with respect to air pollution control equipment and process equipment which affect such emissions:

Develop a maintenance schedule and maintain records of all scheduled and non-scheduled maintenance.

Maintain an inventory of spare parts.

Have available written operating procedures for equipment. These procedures shall be based on the manufacturer's recommendations, at a minimum.

Train operators in the proper operation of all such equipment and familiarize the operators with the written operating procedures, prior to their first operation of such equipment. The permittee shall maintain records of the training provided including the names of trainees, the date of training and the nature of the training.

Records of maintenance and training shall be maintained on site for a period of five years and shall be made available to DEQ personnel upon request.
(9 VAC 5-50-20 E)

Record of Malfunctions – The permittee shall maintain records of the occurrence and duration of any bypass, malfunction, shutdown or failure of the facility or its associated air pollution control equipment that results in excess emissions for more than one hour. Records shall include the date, time, duration, description (emission unit, pollutant affected, cause), corrective action, preventive measures taken and name of person generating the record.
(9VAC 5-20-180 J)

Notification for Facility or Control Equipment Malfunction - The permittee shall furnish notification to the Piedmont Regional Office of malfunctions of the affected facility or related air pollution control equipment that may cause excess emissions for more than one hour, by facsimile transmission, telephone, email, or telegraph. Such notification shall be made as soon as practicable but no later than four daytime business hours after the malfunction is discovered. The permittee shall provide a written statement giving all pertinent facts, including the estimated duration of the breakdown, within two weeks of discovery of the malfunction. When the condition causing the failure or malfunction has been corrected and the equipment is again in operation, the permittee shall notify the Piedmont Regional Office.
(9 VAC 5-20-180 C)

Violation of Ambient Air Quality Standard - The permittee shall, upon request of the DEQ, reduce the level of operation or shut down a facility, as necessary to avoid violating any primary ambient air quality standard and shall not return to normal operation until such time as the ambient air quality standard will not be violated.
(9 VAC 5-20-180 I)

Change of Ownership - In the case of a transfer of ownership of a stationary source, the new owner shall abide by any current permit issued to the previous owner. The new owner shall notify the Piedmont Regional Office of the change of ownership within 30 days of the transfer.
(9 VAC 5-80-1985 E)

Permit Copy - The permittee shall keep a copy of this permit on the premises of the facility to which it applies.
(9 VAC 5-80-1985 E)

STATE-ONLY ENFORCEABLE REQUIREMENTS

The following terms and conditions are included in this permit to implement the requirements of 9 VAC 5-40-130 et seq., 9 VAC 5-50-130 et seq., 9 VAC 5-60-200 et seq. and/or 9 VAC 5-60-300 et seq. and are enforceable only by the Virginia Air Pollution Control Board. Neither their inclusion in this permit nor any resulting public comment period make these terms federally enforceable.

Emission Limits: Toxic Air Pollutants – Emissions from the electric power generation facility shall not exceed the limits specified below:

Pollutant	CAS#	Lb/hr	Tons/yr
Acrolein	107-02-8	0.051	0.23
Formaldehyde	50-00-0	2.26	9.86
Beryllium	7440-41-7	0.00015	0.00064
Cadmium	7440-43-9	0.014	0.059
Chromium	7440-47-3	0.017	0.075
Lead	7439-92-1	*	0.027
Mercury	7439-97-6	*	0.014
Nickel	7440-02-0	0.026	0.12

*Hourly emissions of these pollutants are exempt

Annual emissions shall be calculated monthly as the sum of each consecutive 12-month period. These emissions are derived from the estimated overall emission contribution from operating limits. Exceedance of the operating limits may be considered credible evidence of the exceedance of emission limits. Compliance with these emission limits may be determined as stated in Conditions 0, 0, 0, 0, 0, and 0.
(9 VAC 5-60-320 and 9 VAC 5-80-1625G)

(SOE) Stack Test: Toxic Air Pollutants – An initial performance test shall be conducted for formaldehyde from each combustion turbine generator (CT-1, CT-2, CT-3) to determine compliance with the emission limits contained in Condition 0. The tests shall be performed and demonstrate compliance within 60 days after achieving the maximum production rate at which the facility will be operated but in no event later than 180 days after start-up of the permitted facility. Tests shall be conducted and reported and data reduced as set forth in 9 VAC 5-50-30 and the test methods and procedures contained in each applicable section or subpart listed in 9 VAC 5-50-410. Tests shall be conducted at full load. The details of the tests are to be arranged with the Piedmont Regional Office. The permittee shall submit a test protocol at least 30 days prior to testing. One copy of the test results shall be submitted to the Piedmont Regional Office within 60 days of test completion and shall conform to the test report format enclosed with this permit.
(9 VAC 5-50-30 and 9 VAC 5-80-1675)

(SOE) On Site Records: Toxic Air Pollutants – The permittee shall maintain records of emission data and operating parameters as necessary to demonstrate compliance with this permit. The content and format of such records shall be arranged with the Piedmont Regional Office. These records shall include, but are not limited to the average hourly (in pounds), monthly (in tons), and annual emissions (in tons) of each toxic compound listed in Condition 0. Hourly emissions shall be calculated monthly. Annual emissions shall be calculated monthly as the sum of each consecutive 12-month period. These records shall be available for inspection by DEQ and current for at least the most recent five years.
(9 VAC 5-50-50 and 9 VAC 5-80-1625G)

SOURCE TESTING REPORT FORMAT

Report Cover
1. Plant name and location
2. Units tested at source (indicate Ref. No. used by source in permit or registration)
3. Test Dates.
4. Tester; name, address and report date

Certification
1. Signed by team leader/certified observer (include certification date)
2. Signed by responsible company official
3. *Signed by reviewer

Copy of approved test protocol

Summary
1. Reason for testing
2. Test dates
3. Identification of unit tested & the maximum rated capacity
4. *For each emission unit, a table showing:
    a. Operating rate
    b. Test Methods
    c. Pollutants tested
    d. Test results for each run and the run average
    e. Pollutant standard or limit
5. Summarized process and control equipment data for each run and the average, as required by the test protocol
6. A statement that test was conducted in accordance with the test protocol or identification & discussion of deviations, including the likely impact on results
7. Any other important information

Source Operation
1. Description of process and control devices
2. Process and control equipment flow diagram
3. Sampling port location and dimensioned cross section Attached protocol includes: sketch of stack (elevation view) showing sampling port locations, upstream and downstream flow disturbances and their distances from ports; and a sketch of stack (plan view) showing sampling ports, ducts entering the stack and stack diameter or dimensions

Test Results
1. Detailed test results for each run
2. *Sample calculations
3. *Description of collected samples, to include audits when applicable

Appendix
1. *Raw production data
2. *Raw field data
3. *Laboratory reports
4. *Chain of custody records for lab samples
5. *Calibration procedures and results
6. Project participants and titles
7. Observers' names (industry and agency)
8. Related correspondence
9. Standard procedures

* Not applicable to visible emission evaluations