NRO-086-14

COMMONWEALTH of VIRGINIA

Molly Joseph Ward
Secretary of Natural Resources

DEPARTMENT OF ENVIRONMENTAL QUALITY
NORTHERN REGIONAL OFFICE
13901 Crown Court, Woodbridge, Virginia 22193-1453
(703) 583-3800 Fax (703) 583-3821
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David K. Paylor
Director

Thomas A. Faha
Regional Director

June 11, 2014

Mr. John A. Andrews
Green Energy Partners / Stonewall, LLC
39100 East Colonial Highway
Hamilton, Virginia 20158

Location: Loudoun County
Registration Number: 73826

Dear Mr. Andrews:

Attached is a minor amendment to your PSD/Non-Attainment New Source Review permit to construct and operate an electric power generation facility in accordance with the provisions of the Virginia State Air Pollution Control Board Regulations for the Control and Abatement of Air Pollution. This permit amendment reflects the facility design changes (increase in the Siemens combustion turbine/heat recovery steam generator (HRSG) exhaust stack diameter from 18.5 feet to 21.5 feet and lower maximum rated heat input capacity (430 MMBtu/hr vs 450 MMBtuhr) of the Siemens HRSG duct burners) as presented in the permit application dated May 12, 2014. The associated permit changes are reflected on Page 1 (Signature page), Page 2 ("Introduction" section), Page 3 (Condition 1 - Equipment List), and Page 15 (Annual GHG Emission table). The attached permit document supersedes your permit document dated April 30, 2013, as amended May 31, 2013.

In the course of evaluating the application and arriving at a final decision to approve the project, the Department of Environmental Quality (DEQ) deemed the application complete on May 23, 2014. Public participation was not required for this minor amendment under 9 VAC 5-80-1170, 9 VAC 5-80-1945 and 9 VAC 5-80-2220.

This permit contains legally enforceable conditions. Failure to comply may result in a Notice of Violation and/or civil charges. <u>Please read all permit conditions carefully.</u>

This permit approval to construct and operate shall not relieve Green Energy Partners / Stonewall, LLC of the responsibility to comply with all other local, state, and federal permit regulations.

Please note that any engine-generator set constructed on or after April 1, 2006 may be an affected facility under 40 CFR 60, New Source Performance Standard (NSPS) Subpart IIII (Stationary Compression Ignition Internal Combustion Engine). Also, any engine-generator set on site, regardless of the date constructed, may be subject to 40 CFR 63, National Emission Standards for Hazardous Air Pollutants for Source Categories (MACT) Subpart ZZZZ

(Stationary Reciprocating Internal Combustion Engines). Consequently, the proposed diesel emergency engine generator set and the diesel fire suppression pump engine may be subject to owner/operator requirements of the MACT and NSPS and would need to comply with certain federal emission standards and operating limitations over their useful life. The DEQ advises you, as the owner/operator of any affected unit, to review the NSPS and MACT to ensure compliance with applicable emission standards, operational limitations, and the monitoring, notification, reporting and recordkeeping requirements. Applicable notifications shall be sent to the EPA, Region III. Both the NSPS and MACT can be found at www.ecfr.gov.

The Board's Regulations as contained in Title 9 of the Virginia Administrative Code 5-170-200 provide that you may request a formal hearing from this case decision by filing a petition with the Board within 30 days after this case decision notice was mailed or delivered to you. 9 VAC 5-170-200 provides that you may request direct consideration of the decision by the Board if the Director of the DEQ made the decision. Please consult the relevant regulations for additional requirements for such requests.

As provided by Rule 2A:2 of the Supreme Court of Virginia, you have 30 days from the date you actually received this permit or the date on which it was mailed to you, whichever occurred first, within which to initiate an appeal of this decision by filing a Notice of Appeal with:

David K. Paylor, Director
Department of Environmental Quality
P. O. Box 1105
Richmond, VA 23218

If this permit was delivered to you by mail, three days are added to the thirty-day period in which to file an appeal. Please refer to Part Two A of the Rules of the Supreme Court of Virginia for information on the required content of the Notice of Appeal and for additional requirements governing appeals from decisions of administrative agencies.

If you have any questions concerning this permit, please contact Tom Valentour at (703) 583-3931.

Sincerely,

Thomas A. Faha
Regional Director

TAF/JBL/TMV/73826PSD (6-11-14).docx

Attachment: Amended April 30, 2013 PSD/NANSR Permit

cc: Director, OAPP (electronic file submission)
Manager, Data Analysis (electronic file submission)
Chief, Office of Air Enforcement and Compliance Assistance, U.S. EPA, Region III (electronic file submission)
Manager, Air Compliance

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PREVENTION OF SIGNIFICANT DETERIORATION PERMIT
NON-ATTAINMENT NEW SOURCE REVIEW PERMIT
STATIONARY SOURCE PERMIT TO CONSTRUCT AND OPERATE

This permit includes designated equipment subject to New Source Performance Standards (NSPS).
This permit document supersedes the permit documents dated April 30, 2013 and May 31, 2013.

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

Green Energy Partners / Stonewall, LLC
P.O. Box 660
Hamilton, Virginia 20158
Registration Number: 73826
Plant ID No. 51-107-01019

is authorized to construct and operate:

An electric power generation facility

located at:

20077 Gant Lane
Leesburg, VA 20175 (Loudoun County)
(approximately 4 miles south/south east of
Leesburg & north of Dulles Toll Road (SR 267)
39.058° N Latitude, 77.545° W Longitude

in accordance with the conditions of this permit

Approved on: April 30, 2013, amended on May 31, 2013, and June 11, 2014

Thomas A. Faha
Regional Director

Permit consists of 37 pages
Permit Conditions 1 to 83.
Source Testing Report Format, 1 page.

INTRODUCTION

This permit approval is based on the permit applications dated July 19, 2012 (with additional information submitted on August 16, 2012, and the modeling analysis and revised application which were both submitted on October 5, 2012, November 15, 2012), May 10, 2013, and May 12, 2014. 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 5-80-1110, 9 VAC 5-80-2010, and 9 VAC 5-10-20 of the Commonwealth of Virginia State Air Pollution Control Board's (Board's) Regulations (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 Department of Environmental Quality (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 Board's Regulations. Information provided to federal officials is subject to appropriate federal law and regulations governing confidentiality of such information.

PROCESS REQUIREMENTS

1. **Equipment List**

   Equipment to be constructed at this facility consists of:

   - Two (2) combined-cycle electric power generating units (Ref. No. CCT1 & CCT2) where each unit includes the following emission units:

     - One (1) General Electric natural gas-fired combustion turbine (CT) generator, Model GE 7FA.05, rated at 2,230 million Btu per hour heat input (Ref. No. CT1 & CT2) with inlet evaporative coolers (NSPS Subpart KKKK) and,

     - One (1) 650 million Btu per hour duct fired (Ref. No. DB1 & DB2) heat recovery steam generator (HRSG) that provides steam to a common steam turbine generator (NSPS Subpart KKKK).

     OR

     - One (1) Siemens natural gas-fired combustion turbine (CT) generator, Model SGT6-5000F5, rated at 2,276 million Btu per hour heat input (Ref. No. CT1 & CT2) with inlet evaporative coolers (NSPS Subpart KKKK) and,

- One (1) 430 million Btu per hour duct fired (Ref. No. DB1 & DB2) heat recovery steam generator (HRSG) that provides steam to a common steam turbine generator (NSPS Subpart KKKK).

- One (1) natural gas-fired auxiliary boiler rated at 75 million Btu per hour heat input (Ref. No. AB1) (NSPS Subpart Dc).

- One (1) natural gas-fired fuel gas heater, rated at 20 million Btu per hour heat input (Ref. No. FGH1) (NSPS Subpart Dc).

- One (1) diesel-fired emergency generator, rated at 15.4 million Btu per hour heat input and 1,500 kW electric power output (Ref. No. EG1) (NSPS Subpart IIII and MACT Subpart ZZZZ).

- One (1) diesel-fired emergency fire pump, rated at 2.54 million Btu per hour heat input and 330 BHP mechanical power output (Ref. No. EFP1) (NSPS Subpart IIII and MACT Subpart ZZZZ).

- One (1) ten cell mechanical draft cooling tower rated at 187,400 gallons/minute of cooling water (Ref. No. MCT1- MCT10).

- One (1) 12,000-gallon aqueous ammonia above ground storage tank (Ref. No. AST1).

- One (1) 1,250-gallon diesel above ground storage tank for the emergency generator (Ref. No. AST2).

- One (1) 400-gallon diesel above ground storage tank for the fire pump (Ref. No. AST3).

- Circuit Breakers containing sulfur hexafluoride (SF_6) (Ref. No. CB1)

Specifications included in the permit under this condition are for informational purposes only and do not form enforceable terms or conditions of the permit.
(9 VAC 5-80-1180 D 3, 9 VAC 5-80-2050, and 9 VAC 5-80-1605 A)

2. **Emission Controls: Combustion Turbines (Ref. No. CT1 & CT2) and Heat Recovery Steam Generators (HRSG) Duct Burners (DB1 & DB2)**

   a. NO_X

      Oxides of nitrogen (NO_X) emissions from each combustion turbine (Ref. No. CT1 & CT2) and each heat recovery steam generator (HRSG) duct burner (Ref. No. DB1 & DB2) shall be controlled by dry low-NO_X combustion with selective catalytic reduction (SCR) control system with ammonia injection. The SCR system shall be provided with adequate access for inspection and shall be in operation when the combustion turbines and duct burners are operating, at all times except during start up and shutdown, as defined in Condition 15.

b. CO and VOC
   Carbon monoxide (CO) and volatile organic compounds (VOC) emissions from each combustion turbine (Ref. No. CT1 & CT2) and each heat recovery steam generator (HRSG) duct burner (Ref. No. DB1 & DB2) shall be controlled by an oxidation catalyst and combustion practices as recommended by the equipment manufacturer. The oxidation catalyst shall be provided with adequate access for inspection and shall be in operation when the combustion turbines and duct burners are operating, at all times except during start up and shutdown, as defined in Condition 15.

c. PM-10 and PM-2.5
   Particulate matter (PM-10 and PM-2.5) emissions from each combustion turbine (Ref. No. CT1 & CT2) and each heat recovery steam generator (HRSG) duct burner (Ref. No. DB1 & DB2) shall be controlled by combustion practices as recommended by the equipment manufacturer, and use of pipeline natural gas, as defined in 40 CFR §72.2.

d. Greenhouse Gases
   Greenhouse gas emissions (including carbon dioxide, methane, and nitrous oxide), as CO_2e from the combined cycle gas turbine generators (CT1 & CT2) for both the GE 7FA.05 and Siemens SGT6-5000F5 and associated heat recovery steam generator (HRSG) duct burner (Ref. No. DB1 & DB2) shall be controlled by combustion practices as recommended by the equipment manufacturer, and use of pipeline natural gas, as defined in 40 CFR § 72.2. The combined cycle gas turbine generators and associated HRSG DBs shall operate at a Higher Heating Value (HHV) heat rate, at full load and corrected to ISO conditions, not to exceed 7,340 Btu HHV/kWh gross output without duct burning and 7,780 Btu HHV/kWh gross output with duct burning. Compliance with this limit shall be demonstrated as contained in Conditions 63 and 68.

(9 VAC 5-80-1180, 9 VAC 5-50-260, 9 VAC 5-80-2050, and 9 VAC 5-80-1705 B)

3. **Emission Controls: Auxiliary Boiler (Ref. No. AB1) and Fuel Gas Heater (Ref. No. FGH1)**

   a. NO_X
      Oxides of nitrogen (NO_X) emissions from the auxiliary boiler (Ref. No. AB1) and the fuel gas heater (Ref. No. FGH1) shall be controlled by ultra low-NO_X burners with a NOx performance of 9 ppmvd at 3% O_2 for natural gas. The low NOx burners shall be installed and operated in accordance with manufacturer's specifications.

   b. CO and VOC
      Carbon monoxide (CO) and volatile organic compounds (VOC) emissions from the auxiliary boiler (Ref. No. AB1) and the fuel gas heater (Ref. No. FGH1) shall be controlled by good combustion practices, operator training, and proper emissions unit design, construction and maintenance to achieve a maximum CO emission rate of 50 ppmvd at 3% O_2. Boiler and heater operators shall be trained in the proper operation of all such equipment. (Refer to Condition 75 for training and record keeping requirements).

c. Particulate Matter (PM-10 and PM-2.5)
PM-10 and PM-2.5 emissions from the auxiliary boiler (AB1) and the fuel gas heater (FGH1) shall be controlled by good combustion practices and the use of pipeline-quality natural gas with a sulfur content of no greater than 0.1 grains per 100 standard cubic feet (scf), on a 12-month rolling average.

d. Greenhouse Gases
CO_2e from the auxiliary boiler (AB1) and the fuel gas heater (FGH1) shall be controlled by the use of pipeline-quality natural gas and high efficiency design and operation.

(9 VAC 5-80-1180, 9 VAC 5-50-260, 9 VAC 5-80-1705 B and 9 VAC 5-80-2050)

4. **Emission Controls: Emergency Generator (Ref. No. EG1)**
Oxides of nitrogen (NO_X), carbon monoxide (CO), volatile organic compounds (VOC), and particulate matter (PM-10 and PM-2.5) emissions from the emergency generator (Ref. No. EG1) shall be controlled by combustion practices as recommended by the equipment manufacturer and the use of ultra low sulfur diesel fuel oil with a maximum sulfur content of 15 ppm by weight. CO_2e emissions shall be controlled by high efficiency design and operation.
(9 VAC 5-80-1180, 9 VAC 5-80-1705 B and 9 VAC 5-50-260)

5. **Emission Controls: Emergency Fire Pump (Ref. No. EFP1)**
Oxides of nitrogen (NO_X), carbon monoxide (CO), volatile organic compounds (VOC), and particulate matter (PM-10 and PM-2.5) emissions from the emergency fire pump (Ref. No. EFP1) shall be controlled by combustion practices as recommended by the equipment manufacturer and the use of ultra low sulfur diesel fuel oil with a maximum sulfur content of 15 ppm by weight. CO_2e emissions shall be controlled by high efficiency design and operation.
(9 VAC 5-80-1180, 9 VAC 5-80-1705 B, 9 VAC 5-80-2050, and 9 VAC 5-50-260)

6. **Monitoring Devices: 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 the device manufacturer's written requirements and recommendations. Each monitoring device shall be provided with adequate access for inspection, and shall be in operation when the SCR system is operating.
(9 VAC 5-80-1180, 9 VAC 5-50-20 C, 9 VAC 5-50-260, 9 VAC 5-80-2050, and 9 VAC 5-80-1705 B)

7. **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 the device manufacturer's written requirements and recommendations. Each monitoring device shall be provided with adequate access for inspection and shall be in operation when the oxidation catalyst is operating.
(9 VAC 5-80-1180, 9 VAC 5-50-20 C, 9 VAC 5-50-260, 9 VAC 5-80-2050, and 9 VAC 5-80-1705 B)

8. **Monitoring Device Observation and Documentation: SCR** – The devices used to continuously measure ammonia feed rate and SCR catalyst bed inlet gas temperature 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 5-50-50 H)

9. **Monitoring Device Observation and Documentation: Oxidation Catalyst** - The devices used to continuously measure the catalyst bed inlet and outlet gas temperatures for each oxidation catalyst shall be observed by the permittee with a frequency sufficient to ensure good performance of the oxidation catalyst, but not less than once per day of operation.
(9 VAC 5-50-50 H)

10. **Monitoring Device: Hour Meter** - The emergency generator (Ref. No. EG1) and the emergency fire pump (Ref. No. EFP-1) shall be equipped with a non-resettable hour metering device to monitor the operating hours of each unit. Each monitoring device shall be observed by the permittee with a frequency of not less than once each day that the generator/fire pump is in operation. The permittee shall keep a log of these observations.

    Each monitoring device shall be installed, maintained, calibrated (as appropriate) and operated in accordance with approved procedures which 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 generator/fire pump is operating.
    (9 VAC 5-80-1180 D and 40 CFR 60.4209)

OPERATIONAL LIMITATIONS

11. **Fuel: Natural Gas Fired Units** – The approved fuel for each combustion turbine (Ref. No. CT1 & CT2), each heat recovery steam generator (HRSG) duct burner (Ref. No. DB1 & DB2), the auxiliary boiler (Ref. No. AB1), and the fuel gas heater (Ref. No. FGH1) is pipeline natural gas as defined in 40 CFR § 72.2, with a maximum sulfur content of 0.1 grains or less of total sulfur per 100 standard cubic feet. A standard cubic foot of gas is defined as a cubic foot of gas at standard conditions (68°F and 29.92 in Hg) as specified in 40 CFR § 72.2. No change in fuel type may occur without DEQ approval. A change in the fuel may require a permit to modify and operate.
(9 VAC 5-50-410, 9 VAC 5-80-1705, 9 VAC 5-80-1715, 9 VAC 5-50-260, 9 VAC 5-80-2050, and 40 CFR 60.4330(a)(2))

12. **Fuel Specification: Diesel Fired Units** - The approved fuel for the emergency engine generator (Ref. No. EG1) and the emergency fire pump (Ref. No. EFP1) shall be diesel fuel that meets the specifications below:

    a. Does not exceed the American Society for Testing and Materials (ASTM) specifications, D975, for grade ultra low sulfur 2-D, or grade 2-D S14, or

    b. Has a maximum sulfur content not to exceed 0.0015% by weight (15 ppm), and either a minimum cetane number of forty or maximum aromatic content of thirty-five percent by volume.

(9 VAC 5-80-1180, 9 VAC 5-80-2050, and 9 VAC 5-50-260)

13. **Fuel Certification** - The permittee must use the sources listed in Condition 13.a to demonstrate compliance with Condition 11 and the sources of information in Condition 13.b to demonstrate compliance with Condition 12:

    a. The fuel characteristic in a current, valid purchase contract, tariff sheet or transportation contract for the natural gas, specifying that the maximum total sulfur content for the natural gas is 0.1 grains of sulfur or less per 100 standard cubic feet and / or representative fuel sampling data, which shows that the sulfur content of the fuels does not exceed 2.61×10^{-4} lb SO_2/MMBtu heat input.

       If the permittee elects not to demonstrate the sulfur content using the above option, the permittee may:

       i. Determine and record the total sulfur content of the natural gas once per unit operating day; or,

       ii. Develop custom schedules for determination of the total 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 CRF 60.4370(c)(1) and (c)(2), custom schedules shall be substantiated with data and shall receive prior EPA approval.

    b. The permittee shall obtain a fuel certification from the fuel supplier with each shipment of diesel fuel oil. Each fuel supplier certificate shall contain the following:

       i. The name of the fuel supplier, and
       ii. The date on which the diesel fuel oil was received, and
       iii. The quantity of diesel fuel oil delivered in the shipment, and
       iv. Either a statement that the diesel fuel oil conforms to the requirements of Condition 12 – Fuel Specification, or
       v. Alternately, the permittee shall obtain approval from the Regional Air Compliance Manager of the DEQ's Northern Regional Office (NRO) at the address listed in Condition 57 if other documentation will be used to certify the diesel fuel oil type.

    Fuel sampling and analysis, independent of that used for certification, as may be periodically required or conducted by the DEQ, may be used to determine compliance with the fuel specifications stipulated in Condition 12. Exceedance of these specifications may be considered credible evidence of the exceedance of emission limits.
    (9 VAC 5-80-1180, 9 VAC 5-50-410, 9 VAC 5-80-2050, 9 VAC 170-160, 40 CFR 60.4365(a), 40 CFR 60.4370(b), and 40 CFR 60.4370(c))

14. **Fuel Throughput** – The two GE 7FA.05 combustion turbines (Ref. No. CT1 & CT2) and two 650 MMBtu/hr duct burners (Ref. No. DB1 & DB2) shall not consume more than 4.01×10^{10} cubic feet of natural gas per year, calculated monthly as the sum of each consecutive 12-month period. The two Siemens SGT6-5000F5 combustion turbines (Ref. No. CT1 & CT2) and two 450 MMBtu/hr duct burners (Ref. No. DB1 & DB2) shall not consume more than 4.00×10^{10} cubic feet 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 5-80-1180 and 9 VAC 5-80-2050)

15. **Startup / Shutdown** – The short-term emission limits contained in Condition 33 apply at all times except during periods of startup and shutdown.

    a. Startup and shutdown periods are defined as the average time per turbine for the two turbine plant to complete startup and shutdown as follows:

        i. Cold Startup – refers to restarts made 72 hours or more after shutdown. Exclusion from the short-term emission limits for cold startup periods shall not exceed 226 minutes per occurrence.

        ii. Warm Startup – refers to restarts made more than 4, but less than 72 hours after shutdown. Exclusion from the short-term emission limits for warm startup periods shall not exceed 128 minutes per occurrence.

        iii. Hot Startup – refers to restarts made 4 hours or less after shutdown. Exclusion from the short-term emissions limits for hot startup periods shall not exceed 38 minutes per occurrence.

        iv. Shutdown – refers to the period between the time the turbine load drops below 50 percent operating level and the fuel supply to the turbines is cut. Exclusion from the short-term emissions limits for shut down shall not exceed 14 minutes per occurrence.

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

    c. The permittee shall record the date, time, and duration of each startup and shutdown period. The records must include calculations of NOx 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.

    d. During startup, the combustion turbine SCR system, including ammonia injection, shall be operated in a manner to minimize emissions, as technologically feasible, and not later than when the load reaches 50% of unit output.

    (9 VAC 5-50-260, 9 VAC 5-80-1715, 9 VAC 5-80-1180, and Table 1 to NSPS KKKK of part 60)

16. **Operational Limit – Duct Burners**
    The duct burners (Ref. No. DB1 & DB2) shall not operate independently of each combustion turbine (Ref. No. CT1 & CT2).
    (9 VAC 5-80-1180, 9 VAC 5-80-2050, 9 VAC 5-40-410, and 40 CFR 60.4320)

17. **Operational Limit – Duct Burners**
Each heat recovery steam generator (HRSG) duct burner (Ref. No. DB1 & DB2) shall not operate more than 1,400 hours per year, calculated monthly as the sum of each consecutive twelve month period.
(9 VAC 5-50-260, 9 VAC 5-80-1180, and 9 VAC 5-80-2050)

18. **Requirements by Reference** – Except where this permit is more restrictive than the applicable requirement, the combustion turbines (Ref. No. CT1 & CT2) and the heat recovery steam generator (HRSG) shall be operated in compliance with the requirements of 40 CFR 60, Subpart KKKK.
(9 VAC 5-50-400, 9 VAC 5-50-410, 9 VAC 5-80-1180, 9 VAC 5-80-2050, and 40 CFR 60, Subpart KKKK)

19. **CAIR (Clean Air Interstate Rule) NO_X Annual Trading Requirements** –The combined-cycle power generating units (Ref. No. CCT1 & CCT2) listed in Condition 1 meet the definition of a CAIR NO_X Unit and are subject to the CAIR NO_X emission limits under 9 VAC 5-140-1040 or for opt in sources under 9 VAC 5-140-1800. As required by 9 VAC 5-140-1200 A, for each CAIR NO_X source required to have a federally enforceable permit, such permit will include the CAIR permit to be administered by the permitting authority. The following requirements pertain to the CAIR NO_X Annual Trading program:

    a. Prior to commencement of operation, the permittee shall obtain a CAIR permit, as required by 9 VAC 5-140-1200 A, to be administered by the Virginia Department of Environmental Quality (DEQ) under the authority of 9 VAC 5-80-360 *et seq.*, and 9 VAC 5-140-1010 *et seq.*

    b. As commencement of operation of the permitted facility (the first day a combustion turbine burns fuel), the permittee shall comply with the requirements of the CAIR NO_X emission limitations under 9 VAC 5-140-1040.

    c. Each combined-cycle power generating unit (combustion turbine and heat recovery steam generator) in Condition 1 meets the applicability requirements as provided in 9 VAC 5-140-1040 A.1 and A.2. The permittee shall meet the monitoring, emission calculation, recordkeeping, reporting, and testing requirements as applicable under 9 VAC 5 Chapter 140, Part II, Article 8.

    (9 VAC 5-80-1180, 9 VAC 5-80-2050, and 9 VAC 5 Chapter 140, Part II, Article 8)

20. **Fuel Throughput – Auxiliary Boiler (AB1)**
The auxiliary boiler (Ref. No. AB1) shall not consume more than 6.44×10^8 cubic feet 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 5-80-1180 and 9 VAC 5-80-2050)

21. **Fuel Throughput – Fuel Gas Heater (Ref. No. FGH1)**
The fuel gas heater (Ref. No. FGH1) shall not consume more than 1.72×10^8 cubic feet 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 5-80-1180 and 9 VAC 5-80-2050)

22. **Requirements by Reference** – Except where this permit is more restrictive than the applicable requirement, the auxiliary boiler (Ref. No. AB1) and the fuel gas heater (Ref. No. FGH1) shall be operated in compliance with the requirements of 40 CFR 60, Subpart Dc.
(9 VAC 5-50-400, 9 VAC 5-50-410, 9 VAC 5-80-1180, 9 VAC 5-80-2050, and 40 CFR 60, Subpart Dc)

23. **Emergency Generator and Emergency Fire Pump Operation** – The operation of the emergency generator (Ref. No. EG1) and the emergency fire pump (Ref. No. EFP1) are limited to emergency situations. Emergency situations include emergency generator use to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted and emergency engine use to pump water in case of fire or flood, etc. The emergency generator (Ref. No. EG1) and the emergency fire pump (Ref. No. EFP1) may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by the federal, state, or local government, the manufacturer, the vendor, or the insurance company associated with the engine. Maintenance checks and readiness testing of such units is limited to 100 hours per year for each unit.
(9 VAC 5-80-1180, 40 CFR 60.4211(e), and 40 CFR 60.4219)

24. **Operating Hours: Emergency Generator** – The emergency generator (Ref. No. EG1) shall not operate more than 500 hours 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 5-80-1180 and 9 VAC 5-80-2050)

25. **Operating Hours: Emergency Fire Pump** – The emergency fire pump (Ref. No. EFP1) shall not operate more than 500 hours 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 5-80-1180)

26. **Maintenance and Operation** – The permittee must maintain and operate the emergency generator (Ref. No. EG1) and the emergency fire pump (Ref. No. EFP1) in accordance with the manufacturer's written requirements. In addition, the permittee may only change those settings that are allowed by the equipment manufacturer's written requirements.
(9 VAC 5-80-1180, 9 VAC 5-50-260, 40 CFR 60.4206, and 40 CFR 60.4211)

27. **Emission Controls: Cooling Tower** – Particulate matter emissions from the ten cell mechanical draft cooling tower (Ref. No. MCT1 – MCT10) shall be controlled to a drift rate of 0.0005 percent of the circulating water flow and a total dissolved solids content of the cooling water of no more than 5,000 ppm total dissolved solids.
(9 VAC 5-80-1705 B, 9 VAC 5-50-280 and 9 VAC 5 -80-2050)

28. **Sampling & Monitoring – Ten Cell Mechanical Draft Cooling Tower (Ref. No. MCT1-MCT10)**
The facility shall sample the water used by the ten cell mechanical draft cooling tower (Ref. No. MCT1 – MCT10) for total dissolved solids (TDS) at a frequency of not less than once per month to ensure compliance with the TDS in Condition 27. If the TDS sampling demonstrates compliance for three years of cooling tower operation, then the permittee can request a reduction in the sampling frequency. Samples taken as required by this permit shall be analyzed in accordance with 1 VAC 30-45, Certification for Noncommercial Laboratories, or 1 VAC 30-46, Accreditation for Commercial Environmental Laboratories.
(9 VAC 5-50-260, 9 VAC 5-170-160, 9 VAC 5-80- 2050, and 9 VAC 5-80-2080)

29. **Emission Controls: Electrical Breakers** – Greenhouse gas emissions (including SF_6) from the electrical circuit breakers (Ref No. CB1) shall be controlled by an enclosed circuit breaker, with a maximum annual leakage rate of 1.0 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. Emissions shall be monitored in accordance with the requirements of the Mandatory Greenhouse Gas Reporting Rule for Electrical Transmission and Distribution Equipment Use (40 CFR Part 98, Subpart DD).
(9 VAC 5-80-1705 B, 9 VAC 5-50-280)

30. **Re-tuning** – Excess emissions resulting from the retuning of the combustion turbines (Ref. No. CT1 & CT2) shall be permitted provided that:

    a. Best operational practices are adhered to and the duration of excess emissions shall be minimized but in no case exceed twelve hours per combustion turbine (Ref. No. CT1 & CT2) re-tuning event in any 24 hour period. The operator may request additional hours from the DEQ as long as the notification is done as soon as the source is aware that the re-tuning event will exceed twelve hours.

    b. During each combustion turbine (Ref. No. CT1 & CT2) retuning event, NO_X emission concentrations, based on an hourly average, shall not exceed the NO_X standards of the New Source Performance Standards (NSPS) 40 CFR 60 Subpart KKKK – Standards of Performance for Stationary Combustion Turbines (60.4300 et seq.).

    c. The permittee shall notify the Regional Air Compliance Manager of the DEQ's NRO at the address listed in Condition 57 no less than 24 hours prior to each turbine's retuning event. The notification shall include, but is not limited to:

        i. Identification of the specific turbine to be retuned.
        ii. Reason for the retuning event.
        iii. Measures to be taken to minimize the length of the retuning event.

d. The permittee shall furnish a written report to the Regional Air Compliance Manager of the DEQ's NRO of all the pertinent facts concerning the retuning event, as soon as practicable, but not later than 14 business days after the retuning event. The notification shall include, but is not limited to:

   i. Identification of the turbine that was retuned.
   ii. The magnitude of excess emissions per turbine, 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.

e. NO_X emissions during each turbine's retuning shall be recorded and included in the associated quarterly reports and the total annual emissions as required by this permit.

f. The retuning event for each turbine shall be identified on the Data Acquisition Report.

(9 VAC 5-20-180, 9 VAC 5-50-50, and 9 VAC 5-50-410)

31. **Pollution Prevention: Ammonia** – Compliance with the ammonia emission limit in Condition 33 shall be determined based on a one-hour block average. At least three months prior to startup, the permittee shall submit a plan for approval for monitoring the ammonia emissions and demonstrating compliance with the ammonia emission limit from each SCR system to the Regional Air Compliance Manager of the DEQ's NRO at the address listed in Condition 57. Implementation of the plan shall commence upon startup of the facility. The permittee shall demonstrate compliance with the ammonia emission limit at least 95 percent of the time that the SCR is operating. Compliance with the 95 percent time percentage requirement shall be calculated daily and based on a 30-day rolling period. Alternatively, if on a given day less than 100 hours of operation has occurred in the prior thirty days, compliance with the 95 percent limits may be based on the most recent 100 hours of SCR operation.
(9 VAC 5-80-1180, 9 VAC 170-160, and the Virginia Pollution Prevention Act Subsection 10.1-1425.11)

32. **Pollution Prevention: SCR Replacement** – At least two years prior to a planned replacement of the entire SCR system, the permittee shall conduct a study of technically and economically feasible and commercially available NO_X control devices. The study shall include the cost effectiveness for each control device evaluated, including SCR. The results of the evaluation shall be submitted to the Regional Air Permitting Manager of the DEQ's NRO at the address listed in Condition 57 prior to ordering the new system. In the event the permittee wants to replace the SCR with an alternative control device, such a replacement may not require a permit to modify and operate, providing the new system provides an equal or better level of control.
(9 VAC 5-80-1180, 9 VAC 5-80-2050, 9 VAC 5-170-160, and the Virginia Pollution Prevention Act Subsection 10.1-1425.11)

EMISSION LIMITS

33. Emission Limits - Combined-Cycle Power Generation Units (Ref. No. CCT1 & CCT2)

Short-Term Emission Limits - Emissions from the operation of each combined-cycle power generating unit (Ref. No. CCT1 & CCT2) shall not exceed the limits specified below:

GE 7FA.05

Air Pollutant	Short-Term Emission Limits
Oxides of Nitrogen (as NO_2)	▪ 2.0 ppmvd at 15% O_2 W & w/o DB firing ▪ 21.0 lb/hr with HRSG duct burner firing ▪ 16.2 lb/hr without HRSG duct burner firing
Carbon Monoxide (CO)	▪ 2.0 ppmvd at 15% O_2 with & w/o duct burning. ▪ 12.7 lb/hr with HRSG duct burner firing ▪ 9.9 lb/hr without HRSG duct burner firing
Volatile Organic Compounds (VOCs) (as methane)	▪ 2.4 ppmwv at 15% O_2 with duct burner firing ▪ 1.0 ppmwv at 15% O_2 without duct burner firing ▪ 7.3 lb/hr with HRSG duct burner firing ▪ 2.8 lb/hr without HRSG duct burner firing
PM-10 (Includes filterable and condensibles)	▪ 3.34×10^{-3} lb/MMBtu at full load ▪ 16.2 lb/hr with HRSG duct burner firing ▪ 9.6 lb/hr without HRSG duct burner firing
PM-2.5 (Includes filterable and condensibles)	▪ 3.34×10^{-3} lb/MMBtu at full load ▪ 16.2 lb/hr with HRSG duct burner firing ▪ 9.6 lb/hr without HRSG duct burner firing
Sulfur Dioxide (SO_2)	▪ 2.61×10^{-4} lb/MMBtu ▪ 0.75 lb/hr with HRSG duct burner firing ▪ 0.58 lb/hr without HRSG duct burner firing
Ammonia (NH_3)	▪ 5.0 ppmvd at 15% O_2

Siemens SGT6-5000F5

Air Pollutant	Short-Term Emission Limits
Oxides of Nitrogen (as NO_2)	▪ 2.0 ppmvd at 15% O_2 ▪ 20.4 lb/hr with HRSG duct burner firing ▪ 17.1 lb/hr without HRSG duct burner firing
Carbon Monoxide (CO)	▪ 2.0 ppmvd at 15% O_2 with & w/o duct burning. ▪ 12.5 lb/hr with HRSG duct burner firing ▪ 10.4 lb/hr without HRSG duct burner firing
Volatile Organic Compounds (VOCs) (as methane)	▪ 1.5 ppmwv at 15% O_2 with duct burner firing ▪ 1.0 ppmwv at 15% O_2 without duct burner firing ▪ 5.7 lb/hr with HRSG duct burner firing ▪ 3.0 lb/hr without HRSG duct burner firing
PM-10 (Includes filterable and condensables)	▪ 3.74×10^{-3} lb/MMBtu at full load ▪ 14.5 lb/hr with HRSG duct burner firing ▪ 10.1 lb/hr without HRSG duct burner firing
PM-2.5 (Includes filterable and condensables)	▪ 3.74×10^{-3} lb/MMBtu at full load ▪ 14.5 lb/hr with HRSG duct burner firing ▪ 10.1 lb/hr without HRSG duct burner firing

Sulfur Dioxide (SO_2)	▪ 2.61×10^{-4} lb/MMBtu ▪ 0.70 lb/hr with HRSG duct burner firing ▪ 0.58 lb/hr without HRSG duct burner firing
Ammonia (NH_3)	▪ 5.0 ppmvd at 15% O_2

Where:

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

ppmwv = parts per million by volume on a wet gas basis, corrected to 15 percent O_2.

Short-term emission limits for VOC, PM-10 and PM-2.5 represent averages for a three-hour sampling period. Short-term emission limits for nitrogen oxides and carbon monoxide shall be calculated as one-hour averages.

Unless otherwise specified, limits apply at all times except during startup, shutdown, and malfunction. Periods considered startup and shutdown are defined in Condition 15 of this permit.

Compliance with the SO_2 limit may be determined as stated in Condition 11.

This permit may be changed in accordance with 9 VAC 5-80-1925 and 9 VAC 5-80-2000, to reduce the emission limits based on results from stack testing as required in Conditions 56, 58 and 59 of this permit.

(9 VAC 5-80-1180, 9 VAC 5-50-260, 9 VAC 5-50-410, 9 VAC 5-80-2050, 9 VAC 5-80-1705, 40 CFR 60.4320, 40 CFR 60.4330 and the Virginia Pollution Prevention Act Subsection 10.1-1425.11)

34. **Emission Limits: Combined-Cycle Power Generating Units (Ref. No. CCT1 & CCT2) -** CO_2e emissions from the combined cycle gas turbine generators and associated HRSGs shall not exceed 903 lb/MWh (gross) calculated monthly on a 12-operating month annual average basis. Compliance shall be determined each month by summing the CO_2e emissions for all hours in which power is being generated to the grid during the previous 12 months and dividing that value by the sum of the gross electrical energy output over that same period.
(9 VAC 5-50-280, 9 VAC 5-80-1705, and 9 VAC 5-80-1715)

35. **Annual Process Emission Limits** – Total emissions from the combined operation of the two combined-cycle power generating units (Ref. No. CCT1 & CCT2), including duct burners, shall not exceed the limits specified below:

GE 7FA.05

Pollutant	Annual Emissions (tons per year)
Oxides of Nitrogen (as NO_2)	148.6
Carbon Monoxide (CO)	188.8
Volatile Organic Compounds (VOC)	31.0

PM-10 (Includes filterable and condensables)	93.7
PM-2.5 (Includes filterable and condensables)	93.7
Sulfur Dioxide (SO_2)	5.3
Greenhouse Gases (GHG) Carbon Dioxide Equivalent (CO_2e)	2,418,273

Or:

Siemens SGT6-5000F5

Air Pollutant	Annual Emissions (tons per year)
Oxides of Nitrogen (as NO_2)	154.45
Carbon Monoxide (CO)	124.8
Volatile Organic Compounds (VOC)	45.26
PM-10 (Includes filterable and condensables)	94.68
PM-2.5 (Includes filterable and condensables)	94.68
Sulfur Dioxide (SO_2)	5.26
Greenhouse Gases (GHG) Carbon Dioxide Equivalent (CO_2e)	2,424,396

Annual emission limits 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 limits may be determined as stated in Conditions 11, 14, 17, 47, and 70. Annual emissions shall be calculated as the sum of each consecutive 12-month period.

This permit may be changed in accordance with 9 VAC 5-80-1925, to reduce the emission limit based on results from stack testing as required in Conditions 56, 58 and 59 of this permit.

(9 VAC 5-80-1180, 9 VAC 5-50-260, 9 VAC 5-50-410, 9 VAC 5-80-2050, 9 VAC 5-80-1705, and 9 VAC 5-80-1715)

36. **Visible Emission Limit** – Visible emissions from each combined-cycle power generating unit (Ref. No. CCT1 & CCT2) stack 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 EPA Method 9 (Reference 40 CFR 60, Appendix A). This condition applies at all times except during start up, shutdown (as defined in Condition 15), and malfunction.
(9 VAC 5-50-20, 9 VAC 5-50-260, and 9 VAC 5-80-1705)

37. **Process Emission Limits – Auxiliary Boiler (Ref. No. AB1)**
Emissions from the auxiliary boiler (Ref. No. AB1) shall not exceed the limits specified below:

Pollutant	lb/hr	tons/year
Oxides of Nitrogen (as NO_2)	0.83	3.61
Carbon Monoxide (CO)	2.78	12.15
Volatile Organic Compounds (VOC)	0.15	0.66
PM-10 (Includes filterable and condensibles)	0.15	0.66
PM-2.5 (Includes filterable and condensibles)	0.15	0.66
Greenhouse Gases (GHG) Carbon Dioxide Equivalent (CO_2e)	8,873	38,856

These emissions are derived from the estimated overall emission contribution from operating limits. Exceedance of the operating limits shall be considered credible evidence of the exceedance of emission limits.
(9 VAC 5-50-260 and 9 VAC 5-80-1180)

38. **Process Emission Limits – Fuel Gas Heater (Ref. No. FGH1)**
Emissions from the fuel gas heater (Ref. No. FGH1) shall not exceed the limits specified below:

Pollutant	lb/hr	tons/year
Oxides of Nitrogen (as NO_2)	0.22	0.96
Carbon Monoxide (CO)	0.74	3.24
Greenhouse Gases (GHG) Carbon Dioxide Equivalent (CO_2e)	2,365	10,362

These emissions are derived from the estimated overall emission contribution from the operating limits. Exceedance of the operating limits shall be considered credible evidence of the exceedance of emission limits.
(9 VAC 5-50-260 and 9 VAC 5-80-1180)

39. **Visible Emission Limit** – Visible emissions from both the auxiliary boiler (Ref. No. AB1) and the fuel gas heater (Ref. No. FGH1) stacks shall not exceed 10 percent opacity as determined by EPA Method 9 (Reference 40 CFR 60, Appendix A).
(9 VAC 5-80-1180)

40. **Process Emission Limits – Emergency Generator (Ref. No. EG1)**
Emissions from the emergency generator (Ref. No. EG1) shall not exceed the limits specified below:

Pollutant	lb/hr	tons/year
Oxides of Nitrogen (as NO_2)	21.16	5.29
Carbon Monoxide (CO)	11.57	2.89
Volatile Organic Compounds (VOC)	21.16	5.29
Greenhouse Gases (GHG) Carbon Dioxide Equivalent (CO_2e)	2,534	634

These emissions are derived from the estimated overall emission contribution from operating limits. Exceedance of the operating limits shall be considered credible evidence of the exceedance of emission limits. Compliance with the annual emission limits may be determined as stated in Condition 24.
(9 VAC 5-50-260, 9 VAC 5-80-1180, 9 VAC 5-80- 1785 and 9 VAC 5-80-2050)

41. **Process Emission Limits – Emergency Fire Pump (Ref. No. EFP1)**
Emissions from the emergency fire pump (Ref. No. EFP1) shall not exceed the limits specified below:

Pollutant	lb/hr	tons/year
Oxides of Nitrogen (as NO_2)	2.17	0.54
Carbon Monoxide (CO)	1.90	0.47
Volatile Organic Compounds (VOC)	2.17	0.54
Greenhouse Gases (GHG) Carbon Dioxide Equivalent (CO_2e)	416	104

These emissions are derived from the estimated overall emission contribution from operating limits. Exceedance of the operating limits shall be considered credible evidence of the exceedance of emission limits. Compliance with the annual emission limits may be determined as stated in Condition 25.
(9 VAC 5-50-260, 9 VAC 5-80-1773 and 9 VAC 5-80-2050)

42. **Process Emission Limits – Ten Cell Mechanical Draft Cooling Tower (Ref. No. MCT1 - MCT10)**
Emissions from the ten cell mechanical draft cooling tower (Ref. No. MCT1 – MCT10) shall not exceed the limits specified below:

Pollutant	lb/hr	tons/year
PM-10 (includes filterable and condensibles)	2.35	10.27
PM-2.5 (includes filterable and condensibles)	0.73	3.19

These emissions are derived from the estimated overall emission contribution from operating limits. Exceedance of the operating limits shall be considered credible evidence of the exceedance of emission limits. Compliance with these emission limits may be determined as stated in Conditions 27 and 28.
(9 VAC 5-50-260, 9 VAC 5-80-1180, and 9 VAC 5-80-2050)

43. **Process Emission Limits – Total Annual Facility-Wide Emission Limits**
Emissions from the facility shall not exceed the limits specified below:

Pollutant	GE 7FA.05 tons/year	Siemens SGT6-5000F5 tons/year
Oxides of Nitrogen (as NO_2)	159.0	164.9
Carbon Monoxide (CO)	205.6	143.6
Volatile Organic Compounds (VOC)	37.6	51.9
PM-10 (includes filterable and condensibles)	105.2	106.1
PM-2.5 (includes filterable and condensibles	98.1	99.1
Sulfur Dioxide (SO_2)	5.44	5.37
Greenhouse Gases (GHG) Carbon Dioxide Equivalent (CO_2e)	2,468,468	2,464,490

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.
(9 VAC 5-50-260, 9 VAC 5-80-1180, 9 VAC 5-80-1785 and 9 VAC 5-80-2050)

EMISSION OFFSETS

44. **NO_X (and VOC) Offsets** – The permittee shall secure NO_X emission offsets if the GE 7FA.05 combustion turbines are installed, and NO_X and VOC emission offsets if the Siemens SGT6-5000F5 combustion turbines are installed in accordance with 9 VAC 5-80-2120 and 40 CFR Part 51, Appendix S. The emission offsets are based on total annual facility-wide emissions limits in Condition 43. The offsets shall, at a minimum, meet the following conditions:

    a. The permittee shall secure NO_X emission offsets of no less than 159 tons x 1.15 = 182.85 tons for the GE 7FA.05 combustion turbines, and 164.9 tons x 1.15 = 189.64 tons for the Siemens SGT6-5000F5 combustion turbines. The permittee shall secure VOC emission offsets of no less than 51.9 tons x 1.15 = 59.69 tons for the Siemens SGT6-5000F5 combustion turbines.

    b. The emission reduction credits shall be creditable, surplus, quantifiable, permanent and state and federally enforceable. The baseline for calculating the offsets shall be determined pursuant to the method set forth in 40 CFR Part 51, App S, Subsection IV.C.

    c. The offsets shall be obtained within the Northern Virginia ozone nonattainment area or from another ozone nonattainment area. If the offsets are obtained from another ozone nonattainment area, the following requirements apply:

i. The ozone nonattainment area must have an equal or higher nonattainment classification than the area in which the source is to be located.

ii. For any offsets secured from outside of the Commonwealth of Virginia, the emission reductions must be certified to be surplus, quantifiable, permanent and state and federally enforceable by the state or locality where the emission reductions occurred. Documentation of the certification must be provided to and approved by the DEQ Northern Regional Office prior to the beginning of operation of the facility.

d. Prior to beginning operation, the offsets shall be secured, in effect, and state and federally enforceable.

(9 VAC 5-80-2120 and 40 CFR Part 51, Appendix S)

45. **Offset Timing** – Initial startup and operation of the permitted equipment shall not be initiated until the permittee has provided the DEQ-NRO with an official document from the DEQ and / or the State Agency of the state the offsets were obtained indicating that it recognizes the reduction as creditable and permanent. At a minimum, the document shall state that the emission reduction has not been and will not be credited toward another reduction requirement and that the emissions cannot be resurrected from the same facility without the owner first obtaining a permit under a federally-enforceable new source review program. The document must also provide evidence that the U.S. EPA accepts that the emission reductions are creditable for offset purposes.
(9 VAC 5-80-2120 and 9 VAC 5-80-2050 A.3.a)

46. **Offset Recordkeeping** - The permittee shall maintain at the permitted facility a copy of the following:

i. Identification of each source from which the offsets were obtained. Identification shall include the name, address, and Universal Transverse Mercator (UTM) coordinates of the facility and any identification number assigned to the facility by the air pollution control facility that regulates it.
ii. Certification Document from each air pollution control agency required by Condition 44.c and any supporting documentation.

(9 VAC 5-80-2050 and 9 VAC 5-80-2120)

CONTINOUS EMISSION MONITORING SYSTEMS (CEMS)

47. **CEMS** – Continuous Emission Monitoring Systems (CEMS) shall be installed on CCT1 and CCT2 to measure and record the emissions of NO_X (measured as NO_2) and carbon monoxide (CO), in parts per million by volume (ppmvd) corrected to 15 percent O_2, from each combined-cycle power generating unit (Ref. No. CCT1 & CCT2). CEMS shall also be installed to measure and record the emissions of carbon dioxide (CO2). The NOx CEMS shall be installed, evaluated, and operated, and meet the design specifications of 40 CFR 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 be installed on CCT1 and CCT2 to measure and record the oxygen content of the flue gas at each location where

NO_X and CO emissions are monitored. Heat input and power output for CCT1 and CCT2 shall also be measured and recorded. A CEMS or alternative method as allowed by 40 CFR 75 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 33, NO_X data and CO data shall each be reduced to one-hour rolling blocks. The relative accuracy test audit (RATA) of the NO_X/O_2 CEMS shall be performed on a lb/MMBtu basis.
(9 VAC 5-50-40, 9 VAC 5-80-410, 9 VAC 5-50-420, 40 CFR 75, 40 CFR 60.13, and 40 CFR 60.4340 (b))

48. **CEMS Performance Evaluations (NO_X CEMS)**– Performance evaluations of the NO_X and, if applicable, SO_2 CEMS shall be conducted in accordance with 40 CFR 75, Appendix B , and shall take place during the performance tests under 9 VAC 5-50-30 or within 30 days thereafter. One copy of the performance evaluation report shall be submitted to the DEQ, within 45 days of the evaluation. The continuous monitoring systems shall be installed and operational prior to conducting the initial performance tests. Verification of operational status shall, at a minimum, include completion of the manufacturer's written requirements or recommendations for demonstration of the continuous monitoring system's performance, and subsequent notifications shall be submitted to the DEQ.
(9 VAC 5-50-40, 40 CFR 75, and 40 CFR 60.4345(a))

49. **CEMS Performance Evaluations (CO CEMS)** – Performance evaluations of the CO CEMS shall be conducted in accordance with 40 CFR 60, Appendix B, and shall take place during the performance tests under 9 VAC 5-50-30 or within 30 days thereafter. One copy of the performance evaluation report shall be submitted to the DEQ, within 45 days of the evaluation. The continuous monitoring systems shall be installed and operational prior to conducting the initial performance tests. Verification of operational status shall, at a minimum, include completion of the manufacturer's written requirements or recommendations for demonstration of the continuous monitoring system's performance, and subsequent notifications shall be submitted to the DEQ.
(9 VAC 5-50-40, 40 CFR 60, and 40 CFR 60.4345(a))

50. **CEMS Quality Control Program** – For the NO_X and diluent CEMS, the quality control requirements of 40 CFR Part 75 shall be met. The Quality Assurance Accuracy Specifications for the CO CEMS shall be 40 CFR 60 Appendix F, Procedure 1. A linearity test for NO_X and diluent, and a Cylinder Gas Audit (CGA) for CO shall be performed once per QA operating quarter (≥ 168 hours operation) not to exceed four calendar quarters. A RATA test for each installed CEMS shall be conducted once every four Quality Assurance (QA) operating quarters (≥ 168 hours operation each), not to exceed eight calendar quarters. The provisions for a grace period to complete testing shall apply (40 CFR 75, Appendix B 2.2.4 & 2.3.3). Data validation shall be as defined in 40 CFR Part 75, Appendix B, 2.3.2 with the exception that missing data for CO, resulting from continuous monitor system breakdown, repair, calibration checks, and zero and span adjustments, shall be reported as monitor downtime and not substituted. No bias factor shall be applied to the CO monitored value as per 40 CFR Part 60.
(9 VAC 5-50-40, 40 CFR 60.13, 40 CFR 60.4543(e), and 40 CFR 60)

51. **Excess Emissions and Monitor Downtime for NO_X Continuous Monitoring Systems** – For the purpose of this permit, periods of excess emissions and monitor downtime that must be reported under Condition 53 are defined as follows:

    a. An excess emission is any unit operating period in which the one-hour average NO_X emission rate exceeds the applicable emission limit in Condition 33, and

    b. 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, O_2 concentration, fuel flow rate, steam flow rate, steam temperature, steam pressure, or megawatts. The steam flow rate, steam temperature, and steam pressure are 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)

52. **Excess Emissions and Monitor Downtime for SO_2 Monitoring Systems:** For the purpose of this permit, periods of excess emissions and monitor downtime that must be reported under Condition 53 are defined as follows:

    a. An excess emission occurs each unit operating hour included in the hour beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the combustion turbine exceeds the applicable limit and ending on the date and hour that a subsequent sample is taken that 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 and hour of a required sample, if invalid results are obtained. The period of monitor downtime ends on the date and hour of the next valid sample.

    (9 VAC 5-50-50, 9 VAC 5-50-410, 40 CFR 60.7(c), and 40 CFR 60.4385)

53. **Reports for Continuous Monitoring Systems** – The permittee shall furnish written reports to the Regional Air Compliance Manager of the DEQ's NRO at the address listed in Condition 57 from any process monitored by a CEMS, 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:

    a. 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. For each month in the quarter, report each hour in which a NO_X permit limit is exceeded. The report shall include for each excess emission of NO_X: start time, duration, equipment involved, actual NO_X emissions in ppmvd @ 15% O_2, fuel consumption rate, actual weather conditions (temperature and barometric pressure) and turbine load.

    b. Specific identification of each period of excess emissions that occur during startups, shutdowns or malfunctions of the process, and the nature and cause of the malfunction the corrective action taken, and preventative measures adopted;

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

d. If during the calendar quarter no excess emissions have occurred or the continuous monitoring systems have not been inoperative, repaired or adjusted, such information shall be stated in the report.

e. Excess emission reports for sulfur dioxide and nitrogen dioxide as required in 40 CFR 60.4395.

Copies of the written reports referenced in items a through d above are to be sent to:

Associate Director
Office of Air Enforcement (3 AP 10)
U.S. Environmental Protection Agency
Region III
1650 Arch Street
Philadelphia, PA19103 – 2029

(9 VAC 5-50-50, 9 VAC 5-50-410, 40 CFR 60.7(c), 40 CFR 60.4375(a), and 40 CFR 60.4395)

54. **Excess Emissions for Continuous Monitoring Systems** – For purposes of identifying excess emissions:

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

b. 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 60, Appendix A Method 19. For any hour in which the hourly average of 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.

c. 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, Subpart 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)

TESTING

55. **Testing/Monitoring Ports** – 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 such that volumetric flow rates and pollutant emission rates can be accurately determined by applicable test methods and providing stacks and ducts

that are free from cyclonic flow. Test ports shall be provided in accordance with the applicable performance specification (reference 40 CFR Part 60, Appendices A & B). (9 VAC 5-50-30 F)

56. **Initial Performance Test (CO, VOCs, PM-10 & PM-2.5) – Combustion Turbines** - Initial performance tests shall be conducted on each combined-cycle power generation unit (Ref. No. CCT1 & CCT2) for the following pollutants using the specified methods, as appropriate:

Pollutant	Test Method
Carbon Monoxide (CO)	40 CFR 60, Appendix A, Method 10
Volatile Organic Compounds (VOC)	40 CFR 60, Appendix A, Method 25A
PM-10 & PM-2.5 (includes condensables)	40 CFR 60, Appendix A, Methods 5 or 17 and 19 and 40 CFR 51, Appendix M, Method 201A and 202

Tests shall be conducted to determine compliance with the emission limits contained in Condition 33. 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 startup of the permitted unit. The tests shall be conducted on each combined-cycle power generation unit for two different operating scenarios: natural gas firing with the duct burners off; and natural gas firing with the duct burners on. The 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 Regional Air Compliance Manager of the DEQ's NRO at the address listed in Condition 57. The permittee shall submit a test protocol at least 30 days prior to testing. Two copies, one hard copy, and one electronic copy on removable electronic media, of the test results shall be submitted to the Regional Air Compliance Manager of the DEQ's NRO within 60 days after test completion, but no later than 180 days after startup of the permitted unit 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 5-80-2080)

57. **Correspondence** - All correspondence to DEQ concerning compliance with this permit shall be submitted to the following address:

Regional Air Compliance Manager
Department of Environmental Quality
Northern Regional Office
13901 Crown Court
Woodbridge, VA 22193

(9 VAC 5-50-30, 9 VAC 5-50-410 and 9 VAC 5-80-2050)

58. **Initial Performance Test (NOx) – Combustion Turbines** - Initial performance tests shall be conducted on each combined-cycle power generating unit (Ref. No. CCT1 & CCT2) for oxides of nitrogen (as NO_2) to determine compliance with the limits in Condition 33 as follows:

a. 40 CFR 60, Appendix A, Methods 7E or 20 shall be used to measure the NO_X concentration (in ppm). Sampling traverse points for NO_X and (if applicable) diluent gas are to be selected following EPA Method 20 or EPA Method 1 (non particulate procedures), and sampled for equal time intervals. The sampling must be performed with a transversing single hole probe, or, if feasible, with a stationary multi probe hole that samples each of the points sequentially. Alternatively, a multi-hole probe designed and documented to sample equal volumes from each hole may be used to sample simultaneously at the required points.

b. Notwithstanding Condition 58a above, the permittee may test at fewer points than are specified in Method 1 or Method 20 if the following conditions are met:

   The permittee may perform stratification tests for NO_X and dilutant pursuant to the procedures specified in 40 CFR 75, Appendix A, Section 6.5.6.1(a) through (e). Once the stratification sampling is completed, the permittee may use following alternate sample point section criteria for the performance test:

   i. If each of the individual transverse point NO_X concentrations is within +- 10 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differ by no more than +-5 ppm, or +- 5 percent O_2 from the mean for all traverse points, three points located either 16.7, 50.0, or 83.3 percent of the way across the stack or duct, or for circular stacks or ducts greater than 2.4 meters (7.8 feet) in diameter, at 0.4, 1.2 and 2.0 meters from the wall may be used. The three points must be located along the measurement line that exhibited the highest average NO_X concentration during the stratification test, or

   ii. The permittee may sample at a single point, located at least one meter from the stack wall or at the stack centroid if each of the individual transverse point NO_X concentrations is within +- 2.5 percent of the mean concentration for all transverse points, or the individual transverse point diluent concentration differs by no more than +- 1 ppm or +- 0.15 percent O_2 from the mean for all traverse points.

c. The performance test must be done at any load condition within +- 25 percent of 100 percent peak load. Testing may be performed at the highest achievable load point, if at least 75 percent of peak load cannot be achieved in practice. Three separate test runs for each performance test must be conducted. The minimum time per run is 20 minutes.

d. The permittee must measure the total NO_X emissions after the duct burner rather than after the turbine. The duct burner must be in operation during the performance test.

e. Compliance with the applicable emission limit in Condition 33 must be demonstrated at each tested load level. Compliance is achieved if the three run arithmetic average NO_X emission rate at each tested level meets the applicable emission limit in Condition 33.

f. The performance evaluation of the CEMS may either be conducted separately or (as described in 40 CFR 60.4405) as part of the initial performance test of the affected unit.

g. The ambient temperature must be greater than 0°F during the performance test.

h. The permittee may use the following alternatives to the reference methods and procedures in this condition:

   i. Perform a minimum of nine RATA reference method runs, with a minimum time per run of 21 minutes, at a single load level, within ±25 percent of 100 percent of peak load. The ambient temperature must be greater than 0°F during the RATA runs.

   ii. Compliance with the applicable emission limits in Condition 33 is achieved if the arithmetic average of all the NO_X emission rates for the RATA runs, expressed in ppm, does not exceed the emissions limit.

The tests shall be performed, reported and demonstrate compliance within sixty days after achieving the maximum production rate at which the unit will be operated, but in no event later than 180 days after startup of the permitted unit. Tests shall be conducted and reported and the data reduced as set forth in 9 VAC 5-50-30 and the test methods and procedures contained in each applicable section of 9 VAC 5-50-410. The details of the tests are to be arranged with the Regional Air Compliance Manager of the DEQ's NRO at the address listed in Condition 57. The permittee shall submit a test protocol at least 30 days prior to testing. Two copies of the test results shall be submitted (one on paper, and one on removable electronic media) to the Regional Air Compliance Manager of the DEQ's NRO within 60 days after test completion, but no later than 180 days after startup of the permitted unit and shall conform to the test report format enclosed with this permit.
(9 VAC 5-50-30, 9 VAC 5-80-1180, 9 VAC 5-80-2050, 9 VAC 5-80-2080, 9 VAC 5-50-410, 40 CFR 60.8, 40 CFR 60.4405 and 40 CFR 60.4400)

59. **Initial Performance Test (SO_2) – Combustion Turbines –** Initial performance tests shall be conducted on each combined-cycle power generating unit (Ref. No. CCT1 & CCT2) for sulfur dioxide (SO_2) to determine compliance with the limits in Condition 33. The permittee may use one of the following three (a, b, or c below) to conduct the performance test:

   a. 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 alternately D3246, D4084, D4468, D4810, D6228, D6667, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see 40 CFR 60.17).

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

   c. 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 manual methods for sulfur dioxide ASME PTC 9-10-1981-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 startup of the permitted unit. Tests shall be conducted and reported and the data reduced as set forth in 9 VAC 5-50-30 and the test methods and procedures contained in each applicable section of 9 VAC 5-50-410. The details of the tests are to be arranged with the Regional Air Compliance Manager of the DEQ's NRO at the address listed in Condition 57. The permittee shall submit a test protocol at least 30 days prior to testing. Two copies of the test results (one on paper, and one copy electronically on removable electronic media) shall be submitted to the Regional Air Compliance Manager of the DEQ's NRO within 60 days after test completion, but no later than 180 days after startup of the permitted unit and shall conform to the test report format enclosed with this permit.
(9 VAC 5-50-30, 9 VAC 5-80-1180, 9 VAC 5-80-2050, 9 VAC 5-80-2080, 9 VAC 5-50-410, 40 CFR 60.8, 40 CFR 60.4405 and 40 CFR 60.4400)

60. **Initial Performance Test – Auxiliary Boiler and Fuel Gas Heater** - Initial performance tests shall be conducted on the auxiliary boiler (Ref. No. AB1) and the fuel gas heater (Ref. No. FGH1) for NO_X and CO to determine compliance with the emission limits in Conditions 37 and 38. The tests shall be performed, reported, and demonstrate compliance within 60 days after the boiler 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 startup. Tests shall be conducted and reported and data reduced as set forth in 9 VAC 5-50-30. The details of the tests are to be arranged with the Regional Air Compliance Manager of the DEQ's NRO at the address listed in Condition 57. The permittee shall submit a test protocol at least 30 days prior to testing. Two copies of the test results (one on paper, and one copy electronically on removable electronic media) shall be submitted to the Regional Air Compliance Manager of the DEQ's NRO within 60 days of the test completion but no later than 180 days from after startup of the permitted unit and shall conform to the test report format enclosed with this permit.
(9 VAC 5-50-30, 9 VAC 5-80-1180, 9 VAC 5-80-2050, and 9 VAC 5-80-2080)

61. **Visible Emissions Evaluation – Combustion Turbines** - 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 combined-cycle power generating unit (Ref. No. CCT1 & CCT2) exhaust stack. Each test shall consist of 30 sets of 24 consecutive observations (at 15 second intervals) to yield a six-minute average. The tests shall be conducted on each combined-cycle power generation unit for two different operating scenarios: natural gas firing with the duct burners off; and natural gas firing with the duct burners on. The details of the tests are to be arranged with the Regional Air Compliance Manager of the DEQ's NRO at the listed referenced in Condition 57. The permittee shall submit a test protocol at least 30 days prior to testing. The evaluation shall be performed 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 occur which require rescheduling the testing, the Regional Air Compliance Manager of the DEQ's NRO 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. Two copies, one hard copy and one electronic copy on removable electronic media, of the test results shall be submitted to the Regional Air Compliance Manager of the DEQ's NRO within 60 days after test completion but no later than 180 days after startup of the permitted facility and shall conform to the test report format enclosed with this permit.
(9 VAC 5-50-30, 9 VAC 5-80-1180, 9 VAC 5-80-2050 and 9 VAC 5-80-2080)

62. **Visible Emissions Evaluation – Auxiliary Boiler and Fuel Gas Heater** - Concurrently with the initial performance tests, Visible Emission Evaluations (VEE) in accordance with 40 CFR Part 60, Appendix A, Method 9, shall also be conducted on the auxiliary boiler (Ref. No. AB1) and the fuel gas heater (Ref. No. FGH1) exhaust stacks. 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 Regional Air Compliance Manager of the DEQ's NRO at the address listed in Condition 57. The permittee shall submit a test protocol at least 30 days prior to testing. The evaluation shall be performed within 60 days after achieving the maximum production rate at which the boiler or fuel gas heater, as applicable, will be operated, but in no event later than 180 days after start-up of the permitted unit.

    Should conditions occur which require rescheduling the testing, the Regional Air Compliance Manager of the DEQ's NRO 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. Two copies, one hard copy, and one on removable electronic media of the test results shall be submitted to the Regional Air Compliance Manager of the DEQ's NRO within 60 days after test completion but no later than 180 days after startup of the permitted facility and shall conform to the test report format enclosed with this permit
    (9 VAC 5-50-30, 9 VAC 5-80-1180,.9 VAC 5-80-2050, and 9 VAC 5-80-2080)

63. **Testing: Heat Rate Limit** – Initial compliance testing, using ASME Performance Test Code on Overall Plant Performance (ASME PTC 46-1996) or equivalent method approved by the DEQ's NRO, shall be conducted for the heat rate limit of the combined cycle power generating plant (i.e., a combination of the combustion turbines, HRSG DBs and the steam turbine generator) to show compliance with the heat rate limit contained in Condition 2.d. 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 start-up of the permitted facility. The details of the tests are to be arranged with DEQ's NRO. The permittee shall submit a test protocol at least 30 days prior to testing. Two copies of the test results (one on paper, and one copy electronically on removable electronic media) shall be submitted to the Regional Air Compliance Manager of the DEQ's NRO within 60 days of the test completion but no later than 180 days from after startup of the permitted unit and shall conform to the test report format enclosed with this permit. An exceedance of the heat rate limit is not considered a violation of this permit, but triggers a requirement for the permittee to submit a maintenance plan to DEQ's NRO which specifies the actions the permittee plans to take in order to achieve the heat rate limit contained in Condition 2.d. The details of this plan are to be arranged with DEQ's NRO.
(9 VAC 5-50-30 and 9 VAC 5-80-1675)

64. **Annual SO_2 Performance Test – Combustion Turbines** – Annual performance tests shall be conducted on each combined-cycle combustion turbine (Ref. No. CCT1 & CCT2) for

sulfur dioxide (SO_2) to determine compliance with the limits contained in Condition 33. The permittee may use one of the following three methods (a, b, or c below) to conduct the performance test:

a. 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 analysis 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 alternately D3246, D4084, D4468, D4810, D6228, D6667, or Gas Processors Association Standard 2377 (all of which are incorporated by reference , see 40 CFR 60.17).

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

c. 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 manual methods for sulfur dioxide ASME PTC 9-10-1981-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 Regional Air Compliance Manager of the DEQ's NRO at the address listed in Condition 57. The permittee shall submit a test protocol at least 30 days prior to testing. Two copies of the test results (one on paper, and one copy electronically on removable electronic media) shall be submitted to the Regional Air Compliance Manager of the DEQ's NRO 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 5-80-1180, 9 VAC 5-80-2050, 9 VAC 5-80-2080, 9 VAC 5-50-410, and 40 CFR 60.4415(a))

65. **Biennial VOC, PM-10 & PM-2.5 Performance Test – Combustion Turbines** - Upon completion of the initial performance tests required by Condition 56, the permittee shall conduct biennial performance tests on each combined-cycle power generating unit (Ref. No. CCT1 & CCT2) at 24 month intervals for VOC, PM-10, and PM-2.5 emissions as prescribed in Condition 56. The first such biennial test event shall occur no later than 24 months following completion of the initial performance tests required by Condition 56. If during three consecutive test events, including the initial performance tests, neither unit has tests results that show emissions at greater than 80 percent of the emission limits in Condition 33, the testing interval for each turbine may be expanded up to 60 months upon approval from the Regional Air Compliance Manager of the DEQ's NRO. If any subsequent test results in emissions of greater than 80 percent, biennial testing at no more than 24 month intervals

shall resume. The tests for each turbine may be staggered within the schedule above, so that they are not necessarily conducted for both units in the same calendar year. The tests need only be conducted at the maximum load in the normal operating range and the minimum load of the normal operating range, unless the minimum load is within ten percent of the maximum load, in which case testing is required at only the maximum load. The normal operating range shall be determined from records of actual operation. Upon request by the DEQ, the permittee shall conduct additional performance tests for each combined-cycle power generating unit (Ref. No. CCT1 & CCT2) to demonstrate compliance with the emission limits contained in this permit. The details of the tests shall be agreed upon with the Regional Air Compliance Manager of the DEQ's NRO.
(9 VAC 5-50-30 G, 9 VAC 5-80-1180, 9 VAC 5-80-2050, 9 VAC 5-80-2080, and 9 VAC 5-50-410)

66. **Visible Emissions Evaluation – Combustion Turbines –** After the initial Visible Emissions Evaluation, the permittee shall conduct visible emission inspections on each combined-cycle power generating unit (Ref. No. CCT1 & CCT2) stack in accordance with the following procedures and frequencies:

    a. At a minimum of once per week, the permittee shall observe the exhaust stack of each combined-cycle power generating unit (Ref. No. CCT1 & CCT2) when in operation for the presence of visible emissions. If during the inspection, visible emissions are observed, a visible emissions evaluation (VEE) shall be conducted in accordance with 40 CFR 60, Appendix A, EPA Method 9. The VEE shall be conducted for a minimum of six minutes. If any of the individual observations exceed the applicable standard, the VEE shall be continued for 60 minutes.

    b. If visible emissions inspections conducted during 12 consecutive weeks show no visible emissions for a particular unit stack, the permittee may reduce the monitoring frequency to once per month for that unit stack. Anytime the monthly visible emissions inspections show visible emissions, or when requested by the DEQ, the monitoring frequency shall be increased to once per week for that stack.

    c. The details and results of all visible emission inspections and observations, and VEEs shall be recorded. The permittee shall maintain records of all such events.

    (9 VAC 5-50-20 and 9 VAC 5-80-2080)

67. **Visible Emissions Evaluation – Auxiliary Boiler and Fuel Gas Heater –**The permittee shall conduct visible emission inspections on the auxiliary boiler (Ref. No. AB1) and fuel gas heater (Ref. No. FGH1) stacks in accordance with the following procedures and frequencies:

    a. At a minimum of once per month, the permittee shall observe the exhaust stack of the auxiliary boiler (Ref. No. AB1) and the fuel gas heater (Ref. No. FGH1) when in operation for the presence of visible emissions. If during the inspection, visible emissions are observed, a visible emissions evaluation (VEE) shall be conducted in accordance with 40 CFR 60, Appendix A, EPA Method 9. The VEE shall be conducted for a minimum of six minutes. If any of the observations exceed the applicable standard, the VEE shall be continued for 60 minutes.

b. If visible emission inspections conducted during 12 consecutive months show no visible emissions, the permittee may reduce the monitoring frequency to once per quarter. Anytime the quarterly visible emissions inspections show visible emissions, or when requested by the DEQ, the monitoring frequency shall be increased to once per month.

c. The details and results of all visible emission inspections and observations, and VEEs shall be recorded. The permittee shall maintain records of all such events.

(9 VAC 5-50-20 and 9 VAC 5-80-2080)

68. **Periodic Testing: Heat Rate Limit** – Every five years after initial evaluation of the heat rate limit of the power generation block, the permittee shall conduct a heat rate evaluation of the power generation block to show compliance with the heat rate limit contained in Condition 2 d. The details of the evaluation are to be arranged with DEQ's NRO.
(9 VAC 5-50-30 and 9 VAC 5-80-1675)

69. **Stack Tests** – Upon request by the DEQ, the permittee shall conduct additional performance tests to demonstrate compliance with the emission limits contained in this permit. The details of the stack tests shall be arranged with the Regional Air Compliance Manager of the DEQ's NRO.
(9 VAC 5-50-30 G)

RECORDKEEPING

70. **On Site Records** – 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 Regional Air Compliance Manager of the DEQ's NRO. These records shall include, but are not limited to:

   a. Fuel records to demonstrate compliance with Conditions 11, 12 and 13.

   b. Fuel monitoring device QA/QC for the CEMS per 40 CFR Part 75.

   c. Monthly and annual throughput of natural gas to each combustion turbine (Ref. No. CT1 & CT2). calculated monthly as the sum of each consecutive 12 month period.

   d. Monthly and annual throughput of natural gas to each duct burner (Ref. No. DB1 & DB2), calculated monthly as the sum of each consecutive 12-month period.

   e. Time, date, and duration of each startup, shutdown, malfunction and turbine retuning period for each combined-cycle power generating unit (Ref. No. CCT1 & CCT2).

   f. Annual number of startup and shutdown occurrences for each combined-cycle power generating unit (Ref. No. CCT1 & CCT2), calculated monthly as the sum of each consecutive 12-month period.

   g. Emissions calculations sufficient to verify compliance with the annual emission limits in Condition 35 (Ref. No. CCT1 & CCT2), Condition 37 (Ref. No. AB1), Condition 38 (Ref.

No. FGH1), Condition 40 (Ref. No. EG1), Condition 41 (Ref. No. EFP1), Condition 42 (Ref. No. MCT1 – MCT10), and facility-wide emission limits in Condition 43, calculated monthly as the sum of each consecutive 12-month period. Calculation methods shall be approved by the Regional Air Compliance Manager of the DEQ's NRO

h. Monthly total dissolved solids sampling results from the water used by the ten cell mechanical draft cooling tower.

i. Continuous records of heat input for each combined-cycle power generating unit (Ref. No. CCT1 & CCT2).

j. Continuous records of power output for each combined-cycle power generating unit (Ref. No. CCT1 & CCT2) and the steam turbine generator.

k. Continuous monitoring systems emissions data, calibrations and calibration checks, percent operating time, and excess emissions.

l. Annual hours of operation for the emergency generator (Ref. No. EG1) and the emergency fire pump (Ref. No. EFP1) for emergency purposes, calculated monthly as the sum of each consecutive 12-month period.

m. Records of time, date and duration of operation for the emergency fire water pump (Ref. No. EFP1) and the emergency generator (Ref. No. EG1) for maintenance checks and readiness testing and the operational status of each combined-cycle power generating unit (Ref. No. CCT1 & CCT2) during those maintenance checks and readiness testing.

n. Annual hours of operation for the emergency generator (Ref. No. EG1) and the emergency fire pump (Ref. No. EFP1) for maintenance checks and readiness testing, calculated monthly as the sum of each consecutive 12-month period.

o. All fuel supplier certifications for the emergency generator (Ref. No. EG1) and the emergency fire pump (Ref. No. EFP1) to demonstrate compliance with Condition 13.

p. Operation and control device monitoring records for each SCR system and each oxidation catalyst.

q. Logs of dissolved solids content of cooling water to the ten cell mechanical draft cooling tower (Ref. No. MCT1- MCT10)

r. Records for each combined-cycle power generating unit (Ref. No. CCT1 & CCT2) showing steady state vs. non steady state operation during a given hour, the ammonia emissions monitoring plan, and the ammonia emission monitoring results as required by Condition 31.

s. Scheduled and unscheduled maintenance and operator training.

t. Results of all stack tests, visible emissions evaluations, visible emission inspection results, and performance evaluations.

u. Monthly and annual throughput of natural gas and hours of operation for the auxiliary boiler (Ref. No. AB1) and the fuel gas heater (Ref. No. FGH1), calculated monthly as the sum of each consecutive 12-month period.

v. Records of manufacturer's instructions for proper operation of equipment for the auxiliary boiler (Ref. No. AB1) and the fuel gas heater (Ref. No. FGH1) as required by Condition 3.

w. Records related to NO_X offsets as required by Conditions 44, 45 and 46.

x. Records related to the CEMS quality control program as required in Condition 50.

y. Records to verify compliance with the short term emission factors for GHG in Conditions 33 and 34.

These records shall be available for inspection by the DEQ and shall be current for the most recent five years.
(9 VAC 5-80-1180, 9 VAC 5-80-2050, and 9 VAC 5-50-50)

NOTIFICATIONS

71. **Initial Notifications** – The permittee shall furnish written notification to the Regional Air Compliance Manager of the DEQ's NRO of:

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

b. The actual date of the selection of the turbine and HRSG manufacturer has been selected including model number, and heat input rating within 30 days after such date.

c. Date that emission offsets are identified, and the nature of the offsets within 30 days after such date.

d. 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.

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

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

g. The anticipated date of performance tests of each combined-cycle power generating unit (Ref. No. CCT1 & CCT2) postmarked at least 30 days prior to such date.

h. The actual date on which construction of the auxiliary boiler (Ref. No. AB1) commenced within 30 days after such date.

i. The anticipated start-up date of the auxiliary boiler (Ref. No. AB1) postmarked not more than 60 days nor less than 30 days prior to such date.

j. The actual start-up date of the auxiliary boiler (Ref. No. AB1) within 15 days after such date.

k. The actual date on which construction of the emergency generator (Ref. No. EG1) and emergency fire water pump (Ref. No. EFP1) commenced within 30 days after such date. The notification must contain the following:

   i. Name and address of the permittee,
   ii. The address of the affected source,
   iii. Engine information including make, model, engine family, serial number, model year, maximum engine power and engine displacement.
   iv. Fuel used

l. The anticipated start-up date of the emergency generator (Ref. No. EG1) and emergency fire water pump (Ref. No. EFP1) postmarked not more than 60 days nor less than 30 days prior to such date.

m. The actual start-up date of the emergency generator (Ref. No. EG1) and the emergency fire water pump (Ref. No. EFP1) within 15 days after such date.

Copies of the written notification referenced in items a through d and f through h above are to be sent to the Associate Director of the U.S. EPA at the address in Condition 53.
(9 VAC 5-50-50 and 9 VAC 5-80-1180)

GENERAL CONDITIONS

72. **Permit Invalidation** - This permit to construct and operate an electric power generation facility shall become invalid, unless an extension is granted by the DEQ, if:

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

    b. A program of construction is discontinued for a period of 18 months or more, or is not completed within a reasonable time. This provision does not apply to the period between construction of the approved phases of a phased construction project; each phase must commence construction within 18 months of the projected and approved commencement date.

    DEQ may extend the 18-month period upon a satisfactory showing that an extension is justified
    (9 VAC 5-80-1210, 9 VAC 5-80-1985 and 9-VAC 5-80-2180)

73. **Permit Suspension/Revocation** - The Board may suspend or revoke any permit if the permittee:

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

b. Fails to comply with the terms or conditions of this permit;

c. Fails to comply with any emission standards applicable to an emissions unit included in this permit;

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

e. Fails to operate this facility in conformance with any applicable control strategy, including any emission standards or emission limitations, in the State Implementation Plan if effect at the time an application for this permit is submitted

(9 VAC 5-80-1210 F, 9 VAC 5-80-1985 F and 9 VAC 5-80-1210 G)

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

a. 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;

b. 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;

c. 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

d. 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, 9 VAC 5-80-1180, and 9 VAC 5-80-2050)

75. **Maintenance/Operating Procedures** - At all times, including periods of start-up, shutdown, and malfunction, the permittee shall, to the extent practicable, maintain and operate any affected facility, including associated air pollution control equipment, in a manner consistent with air pollution control practices for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Regional Air Compliance Manager of the DEQ's NRO, which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.

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, monitoring devices, and process equipment which affect such emissions:

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

b. Maintain an inventory of spare parts.

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

d. 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, 9 VAC 5-80-1180 D, and 9 VAC 5-80-2050)

76. **Record of Malfunctions** – The permittee shall maintain records of the occurrence and duration of any bypass, malfunction, shut-down or failure of the facility or its associated air pollution control equipment that results in excess emissions for more than one hour. The records shall be maintained in a form suitable for inspection and maintained for at least two years (unless a longer period is specified in the applicable emission standard) following the date of occurrence. Records shall include the date, time, duration, description (emission unit, pollutant affected, cause of malfunction), corrective action, preventive measures taken and name of person generating the record.
(9 VAC 5-20-180 J, 9 VAC 5-80-1180 D, and 9 VAC 5-80-2050)

77. **Notification for Facility or Control Equipment Malfunction** - The permittee shall furnish notification to the DEQ, 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 or telegraph. Such notification shall be made as soon as practicable, but not 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 14 days of the discovery. Owners subject to the requirements of 9 VAC 5-40-50 C and 9 VAC 5-50-50 C are not required to provide the written statement prescribed in this paragraph for facilities subject to the monitoring requirements of 9 VAC 5-40-40 and 9 VAC 5-50-40. When the condition causing the failure or malfunction has been corrected and the equipment is again operating the permittee shall notify the DEQ, in writing.
(9 VAC 5-20-180 C, 9 VAC 5-80-1180, and 9 VAC 5-80-2050)

78. **Notification for Control Equipment Maintenance** - The permittee shall furnish notification to the Regional Air Compliance Manager of the DEQ's NRO in case of shutdown or bypassing, or both, of air pollution control equipment for necessary scheduled maintenance, which results in excess emissions for more than one hour. The intent to shut down or

bypass such equipment shall be reported to the Regional Air Compliance Manager of the DEQ's NRO and local air pollution control agency, if any, at least 24 hours prior to the planned shutdown. Such prior notice shall include, but is not limited to the following information:

a. Identification of air pollution control equipment to be taken out of service, as well as its location and registration number;

b. The expected length of time that the air pollution control equipment will be out of service;

c. The nature and quantity of emissions of air pollution likely to occur during the shutdown period; and

d. Measures that will be taken to minimize the length of the shutdown or to negate the effect of the outage.

(9 VAC 5-20-180 B)

79. **Violation of Ambient Air Quality Standard** - Regardless of any other provision of this permit, the permittee shall, upon request of the DEQ, reduce the level of operation of the facility if the DEQ determines that is necessary to prevent a violation of any primary ambient air quality standard. Under worst-case conditions, the DEQ may order that the permittee shut down the facility if there is no other method of operation to avoid a violation of the primary ambient air quality standard. The DEQ reserves the right to prescribe the method of determining if a facility will cause such a violation. In such cases, the facility shall not be returned to operation until it and the associated air pollution control equipment are able to operate without violation of any primary ambient air quality standard.
(9 VAC 5-20-180 I)

80. **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 DEQ of the change of ownership within 30 days of the transfer.
(9 VAC 5-80-1985 E and 9 VAC 5-80-1240 B)

81. **Permit Copy** - The permittee shall keep a copy of this permit on the premises of the facility to which it applies.
(9 VAC 5-80-1180, 9 VAC 5-80-1985 E and 9 VAC 5-80-2050)

STATE ONLY ENFORCEABLE REQUIREMENTS

The following terms and conditions are included to implement the requirements of 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.

82. **Emission Limits** – Emissions from the electric power generation facility shall not exceed the limits specified below:

Pollutant	CAS#	lb/hr	Tons/yr
Acrolyn	107-02-8	2.03E-02[a]/2.06 E-02[b]	8.76E-02[a]/ 8.88E-02[b]
Formaldehyde	50-00-0	7.65E-01[a]/7.54E-01[b]	3.09E-00[a]/ 3.11E-00[b]
Cadimum	7440-43-9	6.31E-03[a]/5.95E-03[b]	2.25E-02[a]/2.25E-02[b]
Chromium	7440-47-3	8.04E-03[a]/7.57E-03[b]	2.86E-02[a]/2.86E-02[b]
Nickel	7440-02-0	1.21E-02[a]/1.14E-02[b]	4.29E-02[a]/4.29E-02[b]

[a] Emissions based on GE 7FA.05
[b] Emissions based on Siemens SGT6-5000F5

Annual emissions shall be calculated monthly as the sum of each consecutive 12-month period.
(9 VAC 5-60-320 and 9 VAC 5-80-1625G)

83. **Onsite Records** - 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 Northern Regional Office. These records shall include, but are not limited to the average hourly, monthly, and annual emissions (in pounds and tons) listed in Condition 82 for each toxic compound using the appropriate emission factor from AP-42, (Section 3-1 dated 4/2000 for stationary gas turbines), (Section 1.4 dated 7/1998 for natural gas combustion), (Section 3.3 dated 4/2000 for gasoline and diesel industrial engines) and (Section 3.4 dated 4/2000 for large stationary dual fuel engines) times the appropriate fuel usage for the period.. 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 the 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