Commonwealth of Virginia

VIRGINIA DEPARTMENT OF ENVIRONMENTAL QUALITY

TIDEWATER REGIONAL OFFICE
5636 Southern Boulevard, Virginia Beach, Virginia 23462
(757) 518-2000 FAX (804) 698-4178
www.deq.virginia.gov

Travis A. Voyles
Acting Secretary of Natural and Historic Resources

Michael S. Rolband, PE, PWD, PWS Emeritus
Director
(804) 698-4020

Craig R. Nicol
Regional Director

February 1, 2023

Mr. Robert W. Sauer
Vice President, System Operations
Virginia Electric and Power Company
DBA: Dominion - Elizabeth River CT Station
120 Tredegar Street
Richmond, VA 23219
robert.w.sauer@dominionenergy.com

Location: Chesapeake
Registration No.: 61108

Dear Mr. Sauer:

Attached is a renewal of the Title V permit to operate your facility pursuant to 9VAC5 Chapter 80 Article 3 of the Virginia Regulations for the Control and Abatement of Air Pollution. The attached permit will be in effect beginning February 1, 2023.

In the course of evaluating the application and arriving at a final decision to issue this permit, the Department of Environmental Quality (DEQ) deemed the application complete on May 10, 2017 and solicited written public comments by placing a newspaper advertisement in the Virginian-Pilot on Wednesday, December 14, 2022. The thirty-day required comment period, provided for in 9VAC5-80-670, expired on Friday, January 13, 2023.

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

This permit approval to operate shall not relieve Dominion Elizabeth River Combustion Turbine Station of the responsibility to comply with all other local, state, and federal permit regulations.

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. 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:

Michael S. Rolband, Director
Department of Environmental Quality
PO 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 Mayanni McCourty at 757-647-9026 or email at mayanni.mccourty@deq.virginia.gov.

Sincerely,

Janet F. Weyland
Deputy Regional Director

JFW/MSO/MAM/61108_012_23_T5R_DominionElizRiverCTStation_CvrLtr.docx

Attachment: Permit

cc: John Brandt, DEQ TRO Air Compliance Manager (john.brandt@deq.virginia.gov)
Maya Whitaker, DEQ Office of Air Permit Programs (OAPP) (maya.whitaker@deq.virginia.gov)
Yongtian (Tom) He, PhD, U.S. EPA Region III (He.Yongtian@epa.gov)
Todd Alonzo, Director, Manager, Environmental - Corporate Air Programs (Todd.M.Alonzo@dominionenergy.com)

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Article 3
Federal Operating Permit

This permit is based upon federal Clean Air Act acid rain permitting requirements of Title IV, federal operating permit requirements of Title V, and Chapter 80, Article 3 of the State Air Pollution Control Board Regulations for the Control and Abatement of Air Pollution. Until such time as this permit is reopened and revised, modified, revoked, terminated or expires, the permittee is authorized to operate in accordance with the terms and conditions contained herein. This permit is issued under the authority of Title 10.1, Chapter 13: 10.1-1322 of the Air Pollution Control Law of Virginia. This permit is issued consistent with the Administrative Process Act, 9VAC5-80-360 through 9VAC5-80-700 of the State Air Pollution Control Board Regulations for the Control and Abatement of Air Pollution of the Commonwealth of Virginia.

Authorization to operate a Stationary Source of Air Pollution as described in this permit is hereby granted to:

Permittee Name:	**Virginia Electric and Power Company**
Facility Name:	**Dominion – Elizabeth River CT Station**
Facility Location:	**2837 South Military Highway** **Chesapeake, VA 23323**

Registration Number:	**61108**
Permit Number:	**TRO – 61108**

This permit includes the following programs:

Federally Enforceable Requirements - Clean Air Act
Federally Enforceable Requirements - Title IV Acid Rain Program
Federally Enforceable Requirements – Cross State Air Pollution Control Rule (CSAPR)

February 1, 2023
Effective Date

January 31, 2028
Expiration Date

February 1, 2023
Signature Date

Janet F. Weyland
Deputy Regional Director

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Facility Information

Permittee
Virginia Electric and Power Company
DBA: Dominion – Elizabeth River Combustion Turbine (CT) Station
120 Tredegar Street
Richmond, VA 23219

Responsible Official
Robert W. Sauer
Vice President, System Operations

Acid Rain Designated Representative
Robert W. Sauer
Vice President, System Operations
USEPA ATS-AAR ID number: 2099

Alternate Acid Rain Designated Representative
Mohammed Alfayyoumi
Station Director
USEPA ATS-AAR ID number: 2099

Facility
Dominion – Elizabeth River CT Station
2837 South Military Highway
Chesapeake, VA 23323

Contact Person
Todd Alonzo
Manager, Environmental – Corporate Air Programs
804-432-6622

County-Plant Identification Number: 51-550-00161

NATS Facility Identification Number: 05208700CTZ1-CTZ3

Facility Description: NAICS 221112 – Fossil Fuel Electric Power Generation

The Dominion – Elizabeth River Combustion Turbine (CT) Station is a fossil fuel powered electric power generation facility. The facility consists of three Westinghouse W501D5 simple cycle gas turbines that combust both natural gas and distillate oil (No. 2 fuel oil) to generate electricity. The turbines were manufactured and constructed in 1991 and utilize water injection to control NOx emissions. The turbines are low mass emissions (LME) units as defined in 40CFR72.2. As specified in 40CFR75.19, the turbines use optional NOx emission estimation procedures in lieu of continuous NOx emissions monitoring systems to determine NOx emissions. In addition to the electric generating turbines, the facility currently operates a small gasoline dispensing operation that is subject to Federal Requirements.

Emission Units

Process Equipment to be operated consists of:

Combustion Turbines

Emission Unit ID	Stack ID	Emission Unit Description	Size/Rated Capacity*	Pollution Control Device (PCD) Description *	PCD ID	Pollutant Controlled	Applicable Permit Date
CT-1	S1	Westinghouse W501DS simple cycle combustion turbine with water injection, inlet air fogging, and wet compression system – natural gas (primary)/ #2 fuel oil (secondary) Constructed: 1991	1,553 mmBtu/hr (gas) 1,400 mmBtu/hr (oil)	Water Injection	CT-1A	NOx	Issued 3/5/1991, amended 11/28/2005, 6/13/2007, and 4/10/2008
CT-2	S2	Westinghouse W501DS simple cycle combustion turbine with water injection, inlet air fogging, and wet compression system – natural gas (primary)/ #2 fuel oil (secondary) Constructed: 1991	1,553 mmBtu/hr (gas) 1,400 mmBtu/hr (oil)	Water Injection	CT-2A	NOx	Issued 3/5/1991, amended 11/28/2005, 6/13/2007, and 4/10/2008

CT-3	S3	Westinghouse W501DS simple cycle combustion turbine with water injection, inlet air fogging, and wet compression system – natural gas (primary)/ #2 fuel oil (secondary) Constructed: 1991	1,553 mmBtu/hr (gas) 1,400 mmBtu/hr (oil)	Water Injection	CT-3A	NOx	Issued 3/5/1991, amended 11/28/2005, 6/13/2007, and 4/10/2008

Gasoline Dispensing Operations

Emission Unit ID	Stack ID	Emission Unit Description	Size/Rated Capacity*	Pollution Control Device (PCD) Description*	PCD ID	Pollutant Controlled	Applicable Permit Date
ES-4	--	Gasoline fueling station and aboveground storage tank Constructed: 2016	528 gallons	--	--	--	--

*The Size/Rated capacity is provided for informational purposes only, and is not an applicable requirement.

Fuel Burning Equipment Requirements – (Turbines CT-1, CT-2, and CT-3)

Definitions

1. The following terms, as used in Conditions 2 through 18, shall have the meanings specified below:

   Fuel Transfer - means when the unit's load is lowered temporarily to allow for a fuel switch from either natural gas to No. 2 fuel oil or from No. 2 fuel oil to natural gas.

   Natural Gas - means a naturally occurring fluid mixture of hydrocarbons (e.g., methane, ethane, or propane) produced in geological formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions. Natural gas contains 20.0 grains or less of total sulfur per 100 standard cubic feet. Equivalents of this in other units are as follows: 0.068 weight percent total sulfur, 680 parts per million by weight (ppmw) total sulfur, and 338 parts per million by volume (ppmv) at 20 degrees Celsius total sulfur. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1100 British thermal units (Btu) per standard cubic foot. Natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.

   No Load Testing – means testing the turbine when the turbine is spinning but not generating any electricity.

   Start-up – The period starting when fuel is first combusted and ending when the turbine reaches the allowed operating load (as defined in Condition 3), not to exceed 60 minutes.

   Shutdown – the period starting when the operator initiates a shutdown and ending when fuel is no longer being combusted or when the turbine shutdown is aborted to bring the turbine back on line.

   (9VAC5-80-490)

Limitations

2. Fuel Burning Equipment Requirements - Nitrogen dioxide (NOx) emissions from each turbine (CT-1, CT-2, and CT-3) shall be controlled by the use of water injection. (9VAC5-80-490 and Condition 4 of 4/10/2008 Permit)

3. Fuel Burning Equipment Requirements - Each turbine (CT-1, CT-2, and CT-3) shall be operated at not less than 85% and not greater than 100% of rated capacity, with the exception of startup, shutdown, fuel transfer, and no load testing. The operating rate shall be calculated for each clock hour as an arithmetic average of all valid 2-minute readings (readings during startup or shutdown are not considered valid). 100% rated capacity is defined as the maximum load achievable given ambient weather and gas turbine performance conditions.
(9VAC5-80-490 and Condition 6 of 4/10/2008 Permit)

4. Fuel Burning Equipment Requirements - The three turbines (CT-1, CT-2, and CT-3) (combined) shall not operate more than 6,000 hours per year, and no single unit shall operate for more than 2,500 hours per year, each 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.
(9VAC5-80-490 and Condition 7 of 4/10/2008 Permit)

5. Fuel Burning Equipment Requirements - The approved fuels for each turbine (CT-1, CT-2, and CT-3) are natural gas and distillate oil (No. 2 fuel oil). A change in the fuels may require a permit to modify and operate.
(9VAC5-80-490 and Condition 8 of 4/10/2008 Permit)

6. Fuel Burning Equipment Requirements - The three turbines (combined) shall consume no more than 59.6×10^6 gallons of No. 2 fuel oil (distillate oil) and $9,000 \times 10^6$ 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. Fuel consumption shall be determined for each unit in accordance with the "Long Term Fuel Flow" method (40 CFR Part 75), otherwise consumption shall be determined by a method that has been approved by the Department.
(9VAC5-80-490, 40 CFR 75.19(c)(3)(ii), and Condition 9 of 4/10/2008 Permit)

7. Fuel Burning Equipment Requirements - The distillate oil (No. 2 fuel oil) and natural gas shall meet the specifications below:

   No. 2 fuel oil which meets the ASTM D396 specification for numbers 1 or 2 fuel oil:

Maximum sulfur content:	0.2% by weight
Maximum nitrogen content:	0.05% by weight

   Natural Gas:

Maximum sulfur content:	0.06% by weight or
Maximum sulfur content:	20.0 grains/100 standard cubic feet

   (9VAC5-80-490, 40 CFR 60.333(b), and Condition 10 of 4/10/2008 Permit)

8. Fuel Burning Equipment Requirements - Emissions from the operation of each turbine (CT-1, CT-2, and CT-3) shall not exceed the limits specified below:

Pollutant	Natural Gas: Concentration[(a)] (ppmvd)	Natural Gas: Hourly Limit[(b)] (lbs/hr)	Fuel Oil: Concentration[(a)] (ppmvd)	Fuel Oil: Hourly Limit[(b)] (lbs/hr)	Combined Annual Limit for all Turbines (tons/yr)
Particulate Matter[(c)]	-	6.0	-	22.0	66.0
PM-10[(c)]	-	6.0	-	22.0	66.0
Sulfur Dioxide (SO_2)	-	87.0	-	290.0	870.0
Nitrogen Oxides (as NO_2)	25	139.0	42 (FBN ≤ 0.015, wt %) 42 + 400 FBN (0.015 < FBN ≤ 0.05, wt %)	233.0 344.0	1,032.0
Carbon Monoxide[(c)]	30	87.0	30	84.0	261.0
Volatile Organic Compounds (VOC) [(c)]	4	6.5	16	26.7	80.1
Sulfuric Acid Mist (H_2SO_4) [(c)]	-	13.2	-	44.4	133.2
Beryllium	-	-	-	0.0005	0.0015

[(a)] at ISO conditions and 15% Oxygen
[(b)] Averaged for each operating hour
[(c)] Except during start-up, shutdown and malfunction conditions

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 2 through 7, 11, 13, 14, and 15.

(9VAC5-80-490, 40 CFR 60.332(a)(1), 40 CFR 60.332(a)(4), 40 CFR 60.332(b), and Condition 12 of 4/10/2008 Permit)

9. Fuel Burning Equipment Requirements - Visible Emissions from each turbine (CT-1, CT-2, and CT-3) 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 determined by 40 CFR 60, Appendix A, Method 9. This condition applies at all times except during startup, shutdown, and malfunction.
(9VAC5-80-490, 9VAC5-50-80, and Condition 13 of 4/10/2008 Permit)

10. Fuel Burning Equipment Requirements - At all times, including periods of start-up, shutdown and malfunction, the permittee shall, to the extent practicable, maintain and operate the affected source, including associated air pollution control equipment, in a manner consistent with good air pollution control practices for minimizing emissions.

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.
(9VAC5-80-490, 9VAC5-50-20 E, and Condition 25 of 4/10/2008 Permit)

Monitoring

11. Monitoring Devices - Each turbine shall be equipped with a device to continuously monitor and record, in 1-hour clock averages, the fuel consumption, water injection and the ratio of water to fuel being fired in the turbine. Each monitoring device shall be installed, maintained 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 turbines are operating.
(9VAC5-80-490, 40 CFR 60.334(a), and Condition 5 of 4/10/2008 Permit)

12. Visible Emission Observations (VEO) - The permittee shall perform VEOs on the exhaust stack of each Westinghouse W501D5 simple cycle combustion turbine (CT-1, CT-2, and CT-3) according to the following operation frequency guidelines:

Operating Schedule/History	Observation Frequency
< 20 hrs / year with no OV* Testing	No Observations Required
< 20 hrs / year with OV* Testing	Once per year
20 hrs/yr < hours operated < 200 hrs/yr	Once per year
Hours operated > 200 hrs/yr	Once every 200 hours

* OV testing means Operability Verification testing. Operability Verification testing refers to any periodic tests conducted by the source to assure that the combustion turbines could be put into operation if needed. A visible emissions observation can only be conducted when the combustion turbines are operating at a normal load, which is between 85 and 100 percent.

Each VEO shall be performed for a sufficient period of time (minimum of 6 minutes) to identify the presence of visible emissions. If visible emissions are observed, a Method 9-certified observer shall conduct a VEO. If visible emissions do not appear to exceed 10% opacity, no action shall be required. However, if the observed visible emissions appear to exceed 10% opacity, a visible emission evaluation (VEE) shall be conducted using 40 CFR Part 60, Appendix A, Method 9, for a period of not less than 6 minutes. If the average opacity exceeds 10%, modifications and/or repairs shall be performed to correct the problem. Once the problem is corrected another 6 minute VEE shall be performed to prove that the corrective action taken was effective. The VEE observer shall be Method 9-certified. The permittee shall maintain a log to demonstrate compliance with this condition. The log shall include the date and time of the observations, the observer’s name, whether or not there were visible emissions, any VEO and VEE recordings and any necessary

corrective action taken. The logbook shall be kept at the facility and available for inspection by the DEQ.
(9VAC5-80-490 and Condition 14 of 4/10/2008 Permit)

Recordkeeping

13. Fuel Certification - The permittee shall:

    a. Pipeline No. 2 Fuel Oil:

        i. Sample the oil in the storage tank using approved American Society for Testing and Materials (ASTM) methods after each receipt of oil. The sulfur content and the nitrogen content of the sample shall be determined using approved ASTM methods (ASTM D129, D1266, D1552, D2622, D4294, or D5453 for sulfur and ASTM D2597, D4629 or D5762 for nitrogen.), or any approved ASTM method incorporated in 40 CFR by reference; and
        ii. Receive a statement from the fuel supplier for each delivery stating that the fuel oil received complies with the ASTM specifications (D-396) for numbers 1 or 2 fuel oil or sample the oil and have it tested to verify that the distillate oil complies with the ASTM specifications for numbers 1 or 2 fuel oil.

    b. Natural gas: Obtain documentation that the maximum sulfur content is less than or equal to 20.0 grains/100scf or 0.06 % by weight. Acceptable documentation can be in the form of any of the following if valid and current;

        i. Purchase contract,
        ii. Tariff sheets of transportation,
        iii. Pipeline transportation contracts, and
        iv. Analysis of samples in accordance with 40 CFR Part 75.

    (9VAC5-80-490, 40 CFR 60.333(b), 40 CFR 60.335(b)(10), 40 CFR 60.334(h)(3)(i), and Condition 11 of 4/10/2008 Permit)

14. Fuel Burning Equipment Requirements - The permittee shall maintain records of all emission data and operating parameters necessary to demonstrate compliance with this permit. The content and format of such records shall be arranged with the Tidewater Regional Office. These records shall include, but are not limited to:

    a. Records of the one-hour averages of the water to fuel ratio for each turbine and acceptable range for that hour.
    b. One-hour average records of the operating rate (load rate) expressed as a percentage of rated capacity of each turbine to demonstrate compliance with Condition 3.
    c. Annual hours of operation of each of the combustion turbines and the combined number of hours, calculated monthly as the sum of each consecutive 12-month period.
    d. Annual throughput of No. 2 fuel oil, calculated monthly as the sum of each consecutive 12-month period.

e. Annual throughput of natural gas, calculated monthly as the sum of each consecutive 12-month period.
f. Fuel analyses/certifications to satisfy Conditions 7 and 13.
g. Parameter monitoring plan required by 40 CFR 60.334(g) shall be available on-site.
h. Records of VEO and VEE logs to satisfy Condition 12.
i. Scheduled and unscheduled maintenance and operator training.
j. Monthly and annual NOx emissions (in pounds or tons) from the operation of the three gas turbines (combined). Annual emissions shall be calculated monthly as the sum of each consecutive 12-month period.
k. Description of method used to calculate NOx emissions including equations, examples calculations and procedures used to determine Btu/gal, fuel usage, unit lb/mmBtu, or Btu/cf.

These records shall be available on site for inspection by the Department of Environmental Quality (DEQ) and shall be current for the most recent five years.
(9VAC5-80-490, 9VAC5-50-50, 40 CFR 60.334(g), and Condition 18 and 22 of 4/10/2008 Permit)

Testing

15. Fuel Burning Equipment Requirements – Periodically and upon request by the DEQ, the permittee shall conduct additional performance tests for NOx (by methods referenced in 40 CFR Part 60, Subpart GG), CO (by method 10 or 10B) and VOC (by method pre-approved by DEQ in protocol) from the turbines (as specified below) to demonstrate compliance with the emission limits contained in this permit. Data from the monitoring of water to fuel ratio obtained during the test must be included in the stack test emission report. Two of the three gas turbines shall be tested during each five-year period. Each turbine shall be tested at least once every other testing cycle. Each test shall be conducted while operating the turbine at 85% and 100% load capacities, firing natural gas only and firing fuel oil only. The testing shall be conducted and reported and data reduced as set forth in 9VAC5-50-30. The details and schedule of the tests shall be arranged in advance with the Tidewater Regional Office. The permittee shall submit an approvable test protocol at least 30 days prior to testing. One copy of the test results shall be submitted to the Tidewater Regional Office within 60 days after test completion and shall conform to the test report format enclosed with this permit. A Visible Emissions Evaluation (VEE), in accordance with 40 CFR Part 60, Appendix A, Method 9, shall also be conducted on the gas turbine's exhaust stack at each of the specified load conditions while firing oil. The VEE shall consist of 1 set of 24 consecutive observations (at 15 second intervals) to yield a 6-minute average.
(9VAC5-80-490 E & F and Condition 16 of 4/10/2008 Permit)

16. Fuel Burning Equipment Requirements - The permitted facility shall be constructed so as to allow for emissions testing at any time using appropriate methods. Upon request from DEQ, test ports shall be provided at the appropriate locations.
(9VAC5-80-490, 9VAC5-50-30, and Condition 17 of 4/10/2008 Permit)

Reporting

17. Semi-Annual Reports - The permittee shall submit excess emissions and monitoring downtime reports in accordance with 40 CFR 60.7(c) to the Director, Tidewater Regional Office within 30 days after the end of each semi-annual period. (The semi-annual periods are defined as January 1-June 30 and July 1–December 31. Reports are due by January 30 and July 30 of each year.)

    a. NOx emissions

        i. Periods of excess NOx emissions are defined as any unit operating hour during which the average water-to-fuel ratio, as measured by the continuous monitoring system (CMS), falls below the acceptable water-to-fuel ratio determined to demonstrate compliance with Condition 8 by the most recent performance test. Any unit operating hour in which no water is injected into the turbine shall also be considered an excess emission, including times of startup, shutdown and malfunction.

        ii. Monitor downtime includes, but is not limited to, any unit operating hour in which water is injected into the turbine, but essential parametric data needed to determine the appropriate water to fuel ratio are unavailable or invalid.

        iii. Other excess emissions and downtime period defined:

            a. Periods of excess NOx emissions are defined as any period of time during which the fuel-bound nitrogen (FBN) is greater than 0.05% by weight. The excess emission begins on the date and hour of the sample which shows that N is greater than 0.05% by weight, and ends with the date and hour of a subsequent sample which shows a fuel nitrogen content less than or equal to 0.05% by weight.

            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 that a required sample is taken, if invalid results are obtained. The period of monitor downtime ends on the date and hour of the next valid sample.

    b. SO_2 Emissions

        i. An excess emission occurs for each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel oil being fired in the gas turbine exceeds 0.2% by weight and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit.

ii. An excess emission occurs for each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the natural gas being fired in the gas turbine exceeds 0.06% by weight or 20.0 grains/100 scf and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit.

iii. 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 shall include only unit operating hours, and ends on the date and hour of the next valid sample.

c. Each NOx excess emissions period reported shall include the average water to fuel ratio, average fuel consumption, the fuel sulfur content, ambient conditions (temperature, pressure, and humidity), gas turbine load, and (if applicable) the nitrogen content of the fuel during each excess emission. The permittee does not have to report ambient conditions if they have opted to use the worst case ISO correction factor as specified in 40 CFR60.334(b)(3)(ii), or if they opted not to use the ISO correction equation under the provisions of 40 CFR60.335(b)(1).

One copy of the semi-annual report shall be submitted to the U.S. Environmental Protection Agency at the address specified below:

U.S. Environmental Protection Agency
Region III, Enforcement & Compliance Assurance Division
Air, RCRA & Toxics Branch (3ED21)
Four Penn Center
1600 John F. Kennedy Boulevard
Philadelphia, PA 19103-2852

(9VAC5-80-490 F, 40 CFR 60.334(j), and Condition 19 of 4/10/2008 Permit)

18. Stack Test Notifications - The permittee shall furnish written notification to the Director, Tidewater Regional Office of the anticipated date of performance tests of the Combustion Turbines postmarked at least 30 days prior to such date.

Copies of the written notification referenced above are to be sent to:

U.S. Environmental Protection Agency
Region III, Enforcement & Compliance Assurance Division
Air, RCRA & Toxics Branch (3ED21)
Four Penn Center
1600 John F. Kennedy Boulevard
Philadelphia, PA 19103-2852

(9VAC5-80-490 F, 9VAC5-50-50, and Condition 20 of 4/10/2008 Permit)

Gasoline Dispensing Operations

Limitations

19. Limitations – MACT CCCCCC – The facility must, at all times, operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to DEQ which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source. (9VAC5-80-490, 40 CFR 63.11111, and 40 CFR 63.11115)

20. Limitations – MACT CCCCCC – In accordance with 40 CFR 63 Subpart CCCCCC for gasoline dispensing facilities with monthly throughput less than 10,000 gallons of gasoline:

    a. The permittee must not allow gasoline to be handled in a manner that would result in vapor releases to the atmosphere for extended periods of time. Measures to be taken include, but are not limited to, the following:

        i. Minimize gasoline spills;

        ii. Clean up spills as expeditiously as practicable;

        iii. Cover all open gasoline containers and all gasoline storage tank fill-pipes with a gasketed seal when not in use; and

        iv. Minimize gasoline sent to open waste collection systems that collect and transport gasoline to reclamation and recycling devices, such as oil/water separators.

    b. The permittee is not required to submit notifications or reports as specified in 40 CFR 63.11125, 40 CFR 63.11126, or 40 CFR 63 Subpart A, but you must have records available within 24 hours of a request by DEQ to document your gasoline throughput.

    c. Portable gasoline containers that meet the requirements of 40 CFR Part 59, Subpart F, are considered acceptable for compliance with (a)(iii) of this condition.

    If the throughput of the gasoline dispensing facility ever exceeds an applicable throughput threshold in 40 CFR 63.11111, the gasoline dispensing facility will remain subject to the requirements for sources above the threshold, even if the throughput later falls below the applicable throughput threshold.
    (9VAC5-80-490 and 40 CFR 63.11116)

Monitoring

21. Monitoring - MACT CCCCCC GDF Requirements - The permittee shall monitor the monthly throughput of gasoline to the GDF. Monthly throughput is the total volume of gasoline loaded into, or dispensed from, all the gasoline storage tanks located at a single affected GDF. If an area source has two or more GDF at separate locations within the area source, each GDF is treated as a separate affected source.
(9VAC5-80-490, 9VAC5-60-100, and 40 CFR 63.11111(h))

Recordkeeping

22. Recordkeeping – MACT CCCCCC – The permittee must keep applicable records as specified in 40 CFR 63.11116(b) and 40 CFR 63.11125(d). The records shall include:

    a. Records of the occurrence and duration of each malfunction of operation (i.e., process equipment) or the air pollution control and monitoring equipment.

    b. Records of actions taken during periods of malfunction to minimize emissions in accordance with 40 CFR 63.11115(a), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

    c. Documentation of gasoline throughput.

    The permittee shall maintain records of emission data and operating parameters as necessary to demonstrate compliance with this permit. These records shall be available for inspection by the DEQ and shall be current for the most recent five years.
    (9VAC5-80-490, 40 CFR 63.11111(b), 40 CFR 63.11115, 40 CFR 63.11116(b), and 40 CFR 63.11125(d))

Insignificant Emission Units

23. Insignificant Emission Units - The following emission units at the facility are identified in the application as insignificant emission units under 9VAC5-80-720:

Emission Unit No.	Emission Unit Description	Citation	Pollutants Emitted (9VAC5-80-720B)	Rated Capacity (9VAC5-80-720C)
IL-2	Fuel oil valves, pumps, flanges	9VAC5-80-720 B	VOC	-
IL-5	Turbine lube oil venting	9VAC5-80-720 B	VOC	-

These emission units are presumed to be in compliance with all requirements of the federal Clean Air Act as may apply. Based on this presumption, no monitoring, recordkeeping, or reporting shall be required for these emission units in accordance with 9VAC5-80-490. (9VAC5-80-490)

Permit Shield & Inapplicable Requirements

24. Permit Shield & Inapplicable Requirements - Compliance with the provisions of this permit shall be deemed compliance with all applicable requirements in effect as of the permit issuance date as identified in this permit. This permit shield covers only those applicable requirements covered by terms and conditions in this permit and the following requirements which have been specifically identified as being not applicable to this permitted facility:

Citation	Title of Citation	Description of Applicability
40 CFR 63 Subpart T	National Emission Standards for Halogenated Solvent Cleaning	Dominion does not own or operate any equipment meeting the applicability criteria of this subpart.
40 CFR 63 Subpart VV	National Emission Standards for Oil-Water Separators and Organic-Water Separators	This section is applicable only to facilities subject to other subparts that reference this subpart. Dominion is not subject to any subparts that reference this subpart.
9VAC5-70-10 9VAC5-70-70	Applicability of, and Compliance with, Air Quality Standards; Nonattainment Areas	The Hampton Roads area has been re-designated as an attainment area; therefore, despite its listing in Appendix K, the requirements do not apply.
40 CFR 63 Subpart YYYY	National Emission Standards for Stationary Combustion Turbines	The turbines (CT-1 – CT-3) are considered existing units and are specifically exempted in Section 63.6090(b)(4).
40 CFR 60 Subpart KKKK	Standards of Performance for Stationary Combustion Turbines	This subpart is applicable only to stationary combustion turbines that commenced construction, modification or reconstruction after February 18, 2005.
40 CFR 64	Compliance Assurance Monitoring (CAM)	Units subject to the Acid Rain Program are exempt from the requirements of 40 CFR Part 64, Compliance Assurance Monitoring (CAM).

Nothing in this permit shield shall alter the provisions of §303 of the federal Clean Air Act, including the authority of the administrator under that section, the liability of the owner for any violation of applicable requirements prior to or at the time of permit issuance, or the ability to obtain information by (i) the administrator pursuant to §114 of the federal Clean Air Act or (ii) the DEQ pursuant to §10.1-1307.3 or §10.1-1315 of the Virginia Air Pollution Control Law.
(9VAC5-80-490 and 9VAC5-80-500)

General Conditions

25. General Conditions - Federal Enforceability - All terms and conditions in this permit are enforceable by the administrator and citizens under the federal Clean Air Act, except those that have been designated as only state-enforceable.
(9VAC5-80-490)

26. General Conditions - Permit Expiration

    a. This permit has a fixed term of five years. The expiration date shall be the date five years from the date of issuance. Unless the owner submits a timely and complete application for renewal to the DEQ consistent with the requirements of 9VAC5-80-430, the right of the facility to operate shall be terminated upon permit expiration.

    b. The owner shall submit an application for renewal at least six months but no earlier than eighteen months prior to the date of permit expiration.

    c. If an applicant submits a timely and complete application for an initial permit or renewal under this section, the failure of the source to have a permit or the operation of the source without a permit shall not be a violation of Article 3, Part II of 9VAC5 Chapter 80, until the DEQ takes final action on the application under 9VAC5-80-510.

    d. In accordance with 9VAC5-80-430F.7.d, a complete acid rain permit application shall be binding on the owners and operators and the designated representative of the affected source and the affected units covered by the permit application and shall be enforceable as an acid rain permit from the date of submission of the permit application until the issuance or denial of such permit as a final agency action subject to judicial review.

    e. No source shall operate after the time that it is required to submit a timely and complete application under subsections C and D of 9VAC5-80-430 for a renewal permit, except in compliance with a permit issued under Article 3, Part II of 9VAC5 Chapter 80.

    f. If an applicant submits a timely and complete application under section 9VAC5-80-430 for a permit renewal but the DEQ fails to issue or deny the renewal permit before the end of the term of the previous permit, (i) the previous permit shall not expire until the renewal permit has been issued or denied and (ii) all the terms and conditions of the previous permit, including any permit shield granted pursuant to 9VAC5-80-500, shall remain in effect from the date the application is determined to be complete until the renewal permit is issued or denied.

g. The protection under subsections F 1 and F 5 (ii) of section 9VAC5-80-430 F shall cease to apply if, subsequent to the completeness determination made pursuant section 9VAC5-80-430 D, the applicant fails to submit by the deadline specified in writing by the DEQ any additional information identified as being needed to process the application.

(9VAC5-80-490, 9VAC5-80-430, and 9VAC5-80-530)

27. General Conditions - Recordkeeping and Reporting - All records of monitoring information maintained to demonstrate compliance with the terms and conditions of this permit shall contain, where applicable, the following:

    a. The date, place as defined in the permit, and time of sampling or measurements;

    b. The date(s) analyses were performed;

    c. The company or entity that performed the analyses;

    d. The analytical techniques or methods used;

    e. The results of such analyses; and

    f. The operating conditions existing at the time of sampling or measurement.

    (9VAC5-80-490)

28. General Conditions - Recordkeeping and Reporting - Records of all monitoring data and support information shall be retained for at least five years from the date of the monitoring sample, measurement, report, or application. Support information includes all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by the permit.
(9VAC5-80-490)

29. General Conditions - Recordkeeping and Reporting - The permittee shall submit the results of monitoring contained in any applicable requirement to the DEQ no later than March 1 and September 1 of each calendar year. This report must be signed by a responsible official, consistent with 9VAC5-80-430 G, and shall include:

    a. The time period included in the report. The time periods to be addressed are January 1 to June 30 and July 1 to December 31; and

    b. All deviations from permit requirements. For purpose of this permit, deviations include, but are not limited to:

        i. Exceedances of emissions limitations or operational restrictions;

ii. Excursions from control device operating parameter requirements, as documented by continuous emission monitoring or periodic monitoring, or Compliance Assurance Monitoring (CAM) which indicates an exceedance of emission limitations or operational restrictions; or,

iii. Failure to meet monitoring, recordkeeping, or reporting requirements contained in this permit.

c. If there were no deviations from permit conditions during the time period, the permittee shall include a statement in the report that "no deviations from permit requirements occurred during this semi-annual reporting period."

(9VAC5-80-490)

30. General Conditions - Annual Compliance Certification - Exclusive of any reporting required to assure compliance with the terms and conditions of this permit or as part of a schedule of compliance contained in this permit, the permittee shall submit to the Environmental Protection Agency (EPA) and the DEQ no later than March 1 each calendar year a certification of compliance with all terms and conditions of this permit including emission limitation standards or work practices for the period ending December 31. The compliance certification shall comply with such additional requirements that may be specified pursuant to §114(a)(3) and §504(b) of the federal Clean Air Act. The permittee shall maintain a copy of the certification for five (5) years after submittal of the certification. This certification shall be signed by a responsible official, consistent with 9VAC5-80-430 G, and shall include:

a. The time period included in the certification. The time period to be addressed is January 1 to December 31;

b. The identification of each term or condition of the permit that is the basis of the certification;

c. The compliance status;

d. Whether compliance was continuous or intermittent, and if not continuous, documentation of each incident of non-compliance;

e. Consistent with subsection 9VAC5-80-490 E, the method or methods used for determining the compliance status of the source at the time of certification and over the reporting period;

f. Such other facts as the permit may require to determine the compliance status of the source; and

g. One copy of the annual compliance certification shall be submitted to the EPA in electronic format only. The certification document should be sent to the following electronic mailing address:

R3_APD_Permits@epa.gov
(9VAC5-80-490)

31. General Conditions - Permit Deviation Reporting - The permittee shall notify the Tidewater Regional Office within four daytime business hours after discovery of any deviations from permit requirements which may cause excess emissions for more than one hour, including those attributable to upset conditions as may be defined in this permit. In addition, within 14 days of the discovery, the permittee shall provide a written statement explaining the problem, any corrective actions or preventative measures taken, and the estimated duration of the permit deviation. Owners subject to the requirements of 9VAC5-40-50 C and 9VAC5-50-50 C are not required to provide the written statement prescribed in this paragraph for facilities subject to the monitoring requirements of 9VAC5-40-40 and 9VAC5-50-40. The occurrence should also be reported in the next semi-annual compliance monitoring report pursuant to Condition 31 of this permit.
(9VAC5-80-490)

32. General Conditions - Failure/Malfunction Reporting - In the event that any affected facility or related air pollution control equipment fails or malfunctions in such a manner that may cause excess emissions for more than one hour, the owner shall no later than four daytime business hours after the malfunction is discovered, notify the Tidewater Regional Office of such failure or malfunction and within 14 days provide a written statement giving all pertinent facts, including the estimated duration of the breakdown. Owners subject to the requirements of 9VAC5-40-50 C or 9VAC5-50-50 C are not required to provide the written statement prescribed in this paragraph for facilities subject to the monitoring requirements of 9VAC5-40-40 or 9VAC5-50-40. When the condition causing the failure or malfunction has been corrected and the equipment is again in operation, the owner shall notify the Tidewater Regional Office.
(9VAC5-80-490 and 9VAC5-20-180 C)

33. General Conditions - Failure/Malfunction Reporting - The emission units that have continuous monitors subject to 9VAC5-40-50 C or 9VAC5-50-50 C are not subject to the 14 day written notification.
(9VAC5-80-490, 9VAC5-20-180 C, and 9VAC5-50-50)

34. General Conditions - Failure/Malfunction Reporting - The emission units subject to the reporting and the procedure requirements of 9VAC5-40-50 C or the procedures of 9VAC5-50-50 C are listed below:

a. CT-1

b. CT-2

c. CT-3

(9VAC5-80-490, 9VAC5-20-180 C, and 9VAC5-50-50)

35. General Conditions - Failure/Malfunction Reporting - Each owner required to install a continuous monitoring system (CMS) or monitoring device subject to 9VAC5-40-41 or 9VAC5-50-410 shall submit a written report of excess emissions (as defined in the applicable subpart in 9VAC5-50-410) and either a monitoring systems performance report or a summary report form, or both, to the DEQ semiannually. All semi-annual reports shall be postmarked by the 30th day following the end of each calendar semi-annual period (June 30th and January 30th). All reports shall include the following information:

    a. The magnitude of excess emissions computed in accordance with 40 CFR 60.13(h) or 9VAC5-40-41 B.6, any conversion factors used, and the date and time of commencement and completion of each period of excess emissions;

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

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

    d. When 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.

    All malfunctions of emission units not subject to 9VAC5-40-50 C and 9VAC5-50-50 C require written reports within 14 days of the discovery of the malfunction.
    (9VAC5-80-490, 9VAC5-20-180 C, and 9VAC5-50-50)

36. General Conditions - Severability - The terms of this permit are severable. If any condition, requirement or portion of the permit is held invalid or inapplicable under any circumstance, such invalidity or inapplicability shall not affect or impair the remaining conditions, requirements, or portions of the permit.
    (9VAC5-80-490)

37. General Conditions - Duty to Comply - The permittee shall comply with all terms and conditions of this permit. Any permit noncompliance constitutes a violation of the federal Clean Air Act or the Virginia Air Pollution Control Law or both and is ground for enforcement action; for permit termination, revocation and reissuance, or modification; or, for denial of a permit renewal application.
(9VAC5-80-490)

38. General Conditions - Need to Halt or Reduce Activity not a Defense - It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit.
(9VAC5-80-490)

39. General Conditions - Permit Modification - A physical change in, or change in the method of operation of, this stationary source may be subject to permitting under State Regulations 9VAC5-80-360, 9VAC5-80-1100, 9VAC5-80-1605, or 9VAC5-80-2000 and may require a permit modification and/or revisions except as may be authorized in any approved alternative operating scenarios.
(9VAC5-80-490, 9VAC5-80-550, and 9VAC5-80-660)

40. General Conditions - Property Rights - The permit does not convey any property rights of any sort, or any exclusive privilege.
(9VAC5-80-490)

41. General Conditions - Duty to Submit Information - The permittee shall furnish to the DEQ, within a reasonable time, any information that the DEQ may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit or to determine compliance with the permit. Upon request, the permittee shall also furnish to the DEQ copies of records required to be kept by the permit and, for information claimed to be confidential, the permittee shall furnish such records to the DEQ along with a claim of confidentiality.
(9VAC5-80-490)

42. General Conditions – Duty to Submit Information – Any document (including reports) required in a permit condition to be submitted to the DEQ shall contain a certification by a responsible official that meets the requirements of 9VAC5-80-430 G.
(9VAC5-80-490)

43. General Conditions - Duty to Pay Permit Fees - The owner of any source for which a permit was issued under 9VAC5-80-360 through 9VAC5-80-700 shall pay annual emissions fees, as applicable, consistent with the requirements of 9VAC5-80-310 through 9VAC5-80-350 and annual maintenance fees, as applicable, consistent with the requirements of 9VAC5-80-2310 through 9VAC5-80-2350.
(9VAC5-80-490, 9VAC5-80-310 et seq. and 9VAC5-80-2310 et seq.)

44. General Conditions - Fugitive Dust Emission Standards - During the operation of a stationary source or any other building, structure, facility, or installation, no owner or other person shall cause or permit any materials or property to be handled, transported, stored, used, constructed, altered, repaired, or demolished without taking reasonable precautions to prevent particulate matter from becoming airborne. Such reasonable precautions may include, but are not limited to, the following:

    a. Use, where possible, of water or chemicals for control of dust in the demolition of existing buildings or structures, construction operations, the grading of roads, or the clearing of land;

    b. Application of asphalt, water, or suitable chemicals on dirt roads, materials stockpiles, and other surfaces which may create airborne dust; the paving of roadways and the maintaining of them in a clean condition;

    c. Installation and use of hoods, fans, and fabric filters to enclose and vent the handling of dusty material. Adequate containment methods shall be employed during sandblasting or similar operations;

    d. Open equipment for conveying or transporting material likely to create objectionable air pollution when airborne shall be covered or treated in an equally effective manner at all times when in motion; and,

    e. The prompt removal of spilled or tracked dirt or other materials from paved streets and of dried sediments resulting from soil erosion.

    (9VAC5-80-490 and 9VAC5-50-90)

45. General Conditions - Startup, Shutdown, and Malfunction - At all times, including periods of startup, shutdown, and soot blowing, and malfunction, owners 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 DEQ, which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.
(9VAC5-80-490 and 9VAC5-50-20 E)

46. General Conditions - Alternative Operating Scenarios - Contemporaneously with making a change between reasonably anticipated operating scenarios identified in this permit, the permittee shall record in a log at the permitted facility a record of the scenario under which it is operating. The permit shield described in 9VAC5-80-500 shall extend to all terms and conditions under each such operating scenario. The terms and conditions of each such alternative scenario shall meet all applicable requirements including the requirements of 9VAC5 Chapter 80, Article 3.
(9VAC5-80-490)

47. General Conditions - Inspection and Entry Requirements - The permittee shall allow the DEQ, upon presentation of credentials and other documents as may be required by law, to perform the following:

    a. Enter upon the premises where the source is located or emissions-related activity is conducted, or where records must be kept under the terms and conditions of the permit.

    b. Have access to and copy, at reasonable times, any records that must be kept under the terms and conditions of the permit.

    c. Inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the permit.

    d. Sample or monitor at reasonable times substances or parameters for the purpose of assuring compliance with the permit or applicable requirements.

    (9VAC5-80-490)

48. General Conditions - Reopening for Cause - The permit shall be reopened by the DEQ if additional federal requirements become applicable to a major source with a remaining permit term of three years or more. Such reopening shall be completed no later than 18 months after promulgation of the applicable requirement. No such reopening is required if the effective date of the requirement is later than the date on which the permit is due to expire, unless the original permit or any of its terms and conditions has been extended pursuant to 9VAC5-80-430 F. The conditions for reopening a permit are as follows:

    a. The permit shall be reopened if the DEQ or the administrator determines that the permit contains a material mistake or that inaccurate statements were made in establishing the emissions standards or other terms or conditions of the permit.

b. The permit shall be reopened if the administrator or the DEQ determines that the permit must be revised or revoked to assure compliance with the applicable requirements.

c. The permit shall not be reopened by the DEQ if additional applicable state requirements become applicable to a major source prior to the expiration date established under 9VAC5-80-490 D.

(9VAC5-80-490)

49. General Conditions - Permit Availability - Within five days after receipt of the issued permit, the permittee shall maintain the permit on the premises for which the permit has been issued and shall make the permit immediately available to the DEQ upon request.
(9VAC5-80-490 and 9VAC5-80-510)

50. General Conditions - Transfer of Permits

a. No person shall transfer a permit from one location to another.

b. In the case of a transfer of ownership of an affected source, the new owner shall comply with any current permit issued to the previous owner. The new owner shall notify the DEQ of the change in ownership within 30 days of the transfer and shall comply with the requirements of 9VAC5-80-560.

c. In the case of a name change of an affected source, the owner shall comply with any current permit issued under the previous source name. The owner shall notify the DEQ of the change in source name within 30 days of the name change and shall comply with the requirements of 9VAC5-80-560.

(9VAC5-80-490 and 9VAC5-80-520)

51. General Conditions - Permit Revocation or Termination for Cause - A permit may be revoked or terminated prior to its expiration date if the owner knowingly makes material misstatements in the permit application or any amendments thereto or if the permittee violates, fails, neglects or refuses to comply with the terms or conditions of the permit, any applicable requirements, or the applicable provisions of 9VAC5 Chapter 80 Article 3. The DEQ may suspend, under such conditions and for such period of time as the DEQ may prescribe any permit for any grounds for revocation or termination or for any other violations of these regulations.
(9VAC5-80-490, 9VAC5-80-550, and 9VAC5-80-660)

52. General Conditions - Duty to Supplement or Correct Application - Any applicant who fails to submit any relevant facts or who has submitted incorrect information in a permit application shall, upon becoming aware of such failure or incorrect submittal, promptly submit such supplementary facts or corrections. An applicant shall also provide additional

information as necessary to address any requirements that become applicable to the source after the date a complete application was filed but prior to release of a draft permit.
(9VAC5-80-490 and 9VAC5-80-430)

53. General Conditions - Stratospheric Ozone Protection - If the permittee handles or emits one or more Class I or II substances subject to a standard promulgated under or established by Title VI (Stratospheric Ozone Protection) of the federal Clean Air Act, the permittee shall comply with all applicable sections of 40 CFR Part 82, Subparts A to F.
(9VAC5-80-490 and 40 CFR Part 82, Subparts A-F)

54. General Conditions - Asbestos Requirements – The permittee shall comply with the requirements of National Emissions Standards for Hazardous Air Pollutants (40 CFR 61) Subpart M, National Emission Standards for Asbestos as it applies to the following: Standards for Demolition and Renovation (40 CFR 61.145), Standards for Insulating Materials (40 CFR 61.148), and Standards for Waste Disposal (40 CFR 61.150).
(9VAC5-80-490 and 9VAC5-60-70)

55. General Conditions - Accidental Release Prevention - If the permittee has more, or will have more than a threshold quantity of a regulated substance in a process, as determined by 40 CFR 68.115, the permittee shall comply with the requirements of 40 CFR Part 68.
(9VAC5-80-490 and 40 CFR Part 68)

56. General Conditions - Changes to Permits for Emissions Trading - No permit revision shall be required under any federally approved economic incentives, marketable permits, emissions trading and other similar programs or processes for changes that are provided for in this permit.
(9VAC5-80-490)

57. General Conditions - Emissions Trading - Where the trading of emissions increases and decreases within the permitted facility is to occur within the context of this permit and to the extent that the regulations provide for trading such increases and decreases without a case-by-case approval of each emissions trade:

    a. All terms and conditions required under 9VAC5-80-490, except subsection N, shall be included to determine compliance.

    b. The permit shield described in 9VAC5-80-500 shall extend to all terms and conditions that allow such increases and decreases in emissions.

    c. The owner shall meet all applicable requirements including the requirements of 9VAC5-80-360 through 9VAC5-80-700.

    (9VAC5-80-490)

Title IV (Phase II Acid Rain Program) Permit Allowances and Requirements

58. Phase II Acid Rain Program - Statutory and Regulatory Authorities - In accordance with the Air Pollution Control Law of Virginia §10.1-1308 and §10.1-1322, the Environmental Protection Agency (EPA) Final Full Approval of the Operating Permits Program (Titles IV and V) published in the Federal Register December 4, 2001, Volume 66, Number 233, Rules and Regulations, Pages 62961-62967 and effective November 30, 2001, and Title 40, the Code of Federal Regulations §§72.1 through 76.16, the Commonwealth of Virginia Department of Environmental Quality (DEQ) issues this permit pursuant to 9VAC5 Chapter 80, Article 3 of the Virginia Regulations for the Control and Abatement of Air Pollution (Federal Operating Permit Article 3).
(9VAC5-80-490)

59. Phase II Acid Rain Program - Permit Requirements

    a. The designated representative of each affected source and each affected unit at the source shall:

        i. Submit a complete Acid Rain Permit application and acid rain compliance plan under 40 CFR Part 72 in accordance with the deadlines specified in 40 CFR 72.30; and

        ii. Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review an Acid Rain permit application and issue or deny an Acid Rain permit.

    b. The owners and operators of each affected source and each affected unit at the source shall:

        i. Operate the unit in compliance with a complete Acid Rain permit application or a superseding Acid Rain permit issued by the permitting authority; and

        ii. Have an Acid Rain Permit.

    (9VAC5-80-420, 9VAC5-80-430, 9VAC5-80-490, and 40 CFR Part 72.9(a))

60. Phase II Acid Rain Program - Monitoring Requirements

    a. The owners and operators and, to the extent applicable, designated representative of each affected source and each affected unit at the source shall comply with the monitoring requirements as provided in 40 CFR Part 75.

    b. The emissions measurements recorded and reported in accordance with 40 CFR Part 75 shall be used to determine compliance by the source or unit, as appropriate, with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.

c. The requirements of 40 CFR Part 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements of the federal Clean Air Act and other provisions of the operating permit for the source.

(9VAC5-80-490 and 40 CFR 72.9(b))

61. Phase II Acid Rain Program - Sulfur Dioxide Requirements

a. The owners and operators of each source and each affected unit at the source shall:

i. Hold allowances, as of the allowance transfer deadline, in the source's compliance account (after deductions under 40 CFR 73.34(c)), not less than the total annual emissions of sulfur dioxide for the previous calendar year from the affected units at the source; and

ii. SO_2 Allowance Allocations for affected units - Because Emission Units CT-1, CT-2, and CT-3 were not eligible for SO_2 allowance allocations by the U.S. EPA under Section 405 of the Clean Air Act and the Acid Rain Program, no allocations were assigned in 40 CFR Part 73, Table 2 to comply with the applicable Acid Rain emissions limitations for sulfur dioxide as listed in Table 2 of 40 CFR 73.10.

(9VAC5-80-420, 9VAC5-80-490, and 40 CFR Parts 72 and 73)

62. Phase II Acid Rain Program – Sulfur Dioxide Requirements

a. Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the federal Clean Air Act.

b. An affected unit shall be subject to the requirements under 9VAC5-80-420 C.1. as follows:

i. Starting January 1, 1995, an affected unit under 9VAC5-80-380 A.2.; or

ii. Starting on the later of January 1, 1995, in accordance with 40 CFR 72.41 and 72.43, an affected unit under 40 CFR 72.6(a)(2) or (3) that is a substitution or compensating unit; or

iii. Starting January 1, 2000, an affected unit under 40 CFR 72.6(a)(2) that is not a substitution or compensating unit; or

iv. Starting on the later of January 1, 2000 or the deadline for monitor certification under 40 CFR Part 75, an affected unit under 9VAC5-80-380 A.3. that is not a substitution or compensating unit.

c. Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.

d. An allowance shall not be deducted in order to comply with the sulfur dioxide requirements of 40 CFR 72.9(c)(1)(i) prior to the calendar year for which the allowance was allocated.

e. An allowance allocated by the EPA Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.

f. An allowance allocated by the EPA Administrator under the Acid Rain Program does not constitute a property right.

(9VAC5-80-420, 9VAC5-80-490, and 40 CFR 72.9(c))

63. Phase II Acid Rain Program - Nitrogen Oxides Requirements - The emission units (CT-1, CT-2, and CT-3) do not burn coal so there are no NO_X emission limits.
(9VAC5-80-490 and 40 CFR 72.9(d))

64. Phase II Acid Rain Program - Excess Emissions Requirements

a. The designated representative of an affected source that has excess emissions in any calendar year shall submit a proposed offset plan, as required under 40 CFR Part 77.

b. The owners and operators of an affected source that has excess emissions in any calendar year shall:

i. Pay without demand the penalty required, and pay upon demand the interest on that penalty, as required by 40 CFR Part 77; and

ii. Comply with the terms of an approved offset plan, as required by 40 CFR Part 77.

(9VAC5-80-420, 9VAC5-80-490, and 40 CFR 72.9(e))

65. Phase II Acid Rain Program - Recordkeeping and Reporting Requirements

a. Unless otherwise provided, the owners and operators of the source and each affected unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the Administrator or permitting authority:

i. The certificate of representation for the designated representative for the source and each affected unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with 40 CFR 72.24; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative;

ii. All emissions monitoring information, in accordance with 40 CFR Part 75, provided that to the extent that 40 CFR Part 75 provides for a 3-year period for recordkeeping, the 3-year period shall apply.

iii. Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,

iv. Copies of all documents used to complete an Acid Rain permit application and any other submission under the Acid Rain Program or to demonstrate compliance with the requirements of the Acid Rain Program.

b. The designated representative of an affected source and each affected unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR Part 72 Subpart I and 40 CFR Part 75.

(9VAC5-80-420, 9VAC5-80-490, and 40 CFR 72.9(f))

66. Phase II Acid Rain Program - Liability

a. Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain permit application, an Acid Rain permit, or an exemption under 9VAC5-80-390 or 9VAC5-80-400 and 40 CFR 72.7 or 72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to section 113(c) of the federal Clean Air Act and by the DEQ pursuant to §§ 10.1-1316 and 10.1-1320 of the Code of Virginia.

b. Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to section 113(c) of the federal Clean Air Act and 18 U.S.C. 1001 and by the DEQ pursuant to §§ 10.1-1316 and 10.1-1320 of the Code of Virginia.

c. No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.

d. Each affected source and each affected unit shall meet the requirements of the Acid Rain Program.

e. Any provision of the Acid Rain Program that applies to an affected source (including a provision applicable to the designated representative of an affected source) shall also apply to the owners and operators of such source and of the affected units at the source.

f. Any provision of the Acid Rain Program that applies to an affected unit (including a provision applicable to the designated representative of an affected unit) shall also apply to the owners and operators of such unit.

g. Each violation of a provision of the Acid Rain Program regulations (40 CFR Parts 72, 73, 74, 75, 76, 77, and 78) by an affected source or affected unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the federal Clean Air Act.

(9VAC5-80-420, 9VAC5-80-490, and 40 CFR 72.9(g))

67. Phase II Acid Rain Program - Effect on Other Authorities - No provision of the Acid Rain Program, an Acid Rain permit application, an Acid Rain permit, or an exemption under 9VAC5-80-390 or 9VAC5-80-400 and 40 CFR 72.7 or 72.8 shall be construed as:

a. Except as expressly provided in Title IV of the federal Clean Air Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an affected source or affected unit from compliance with any other provision of the federal Clean Air Act, including the provisions of title I of the federal Clean Air Act relating to applicable National Ambient Air Quality Standards or State Implementation Plans;

b. Limiting the number of allowances a source can hold; *provided*, that the number of allowances held by the source shall not affect the source's obligation to comply with any other provisions of the federal Clean Air Act;

c. Requiring a change of any kind in any State law regulating electric utility rates and charges, affecting any State law regarding such State regulation, or limiting such State regulation, including any prudence review requirements under such State law;

d. Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or,

e. Interfering with or impairing any program for competitive bidding for power supply in a State in which such program is established.

(9VAC5-80-420, 9VAC5-80-490, and 40 CFR 72.9(h))

Cross State Air Pollution Rule (CSAPR)

The CSAPR subject units and the unit-specific monitoring provisions are identified in the following table. The units are subject to the requirements for the CSAPR NOx Annual Trading Program, CSAPR SO_2 Group 1 Trading Program, and CSAPR NOx Ozone Season Group 3 Trading Program.

Unit ID: CT-1, CT-2, and CT-3

Parameter	**Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR 75 Subpart B (for SO_2 monitoring) and 40 CFR 75 Subpart H (for NO_X monitoring)**	**Excepted monitoring system requirements for gas- and oil-fired units pursuant to 40 CFR 75 Appendix D**	**Excepted monitoring system requirements for gas- and oil-fired peaking units pursuant to 40 CFR 75 Appendix E**	**Low Mass Emissions excepted monitoring (LME) requirements for gas- and oil-fired units pursuant to 40 CFR 75.19**	**EPA-approved alternative monitoring system requirements pursuant to 40 CFR 75 Subpart E**
SO_2	--------	--------	--------	X	--------
NO_X	--------	--------	--------	X	--------
Heat Input	--------	--------	--------	X	--------

68. **CSAPR –** The above description of the monitoring used by a unit does not change, create an exemption from, or otherwise affect the monitoring, recordkeeping, and reporting requirements applicable to the unit under 40 CFR 97.430 through 97.435 (CSAPR NOx Annual Trading Program), 97.630 through 97.635 (CSAPR SO_2 Group 1 Trading Program), and 97.1030 through 97.1035 (CSAPR NOx Ozone Season Group 3 Trading Program). The monitoring, recordkeeping and reporting requirements applicable to each unit are included below in the standard conditions for the applicable CSAPR trading programs. (9VAC5-80-490 and 40 CFR 97)

69. **CSAPR –** Owners and operators must submit to the Administrator a monitoring plan for each unit in accordance with 40 CFR 75.53, 75.62 and 75.73, as applicable. The monitoring plan for each unit is available at www.epa.gov/airmarkets/monitoring-plans-part-75-sources.
(9VAC5-80-490 and 40 CFR 97)

70. **CSAPR –** Owners and operators that want to use an alternative monitoring system must submit to the Administrator a petition requesting approval of the alternative monitoring system in accordance with 40 CFR part 75, subpart E and 40 CFR 75.66 and 97.435 (CSAPR NOx Annual Trading Program), 97.635 (CSAPR SO_2 Group 1 Trading Program), and 97.1035 (CSAPR NOx Ozone Season Group 3 Trading Program). The Administrator's response approving or disapproving any petition for an alternative monitoring system is available on the EPA's website at www.epa.gov/airmarkets/part-75-petition-responses.
(9VAC5-80-490 and 40 CFR 97)

71. **CSAPR –** Owners and operators that want to use an alternative to any monitoring, recordkeeping, or reporting requirement under 40 CFR 97.430 through 97.434 (CSAPR NOx Annual Trading Program), 97.630 through 97.634 (CSAPR SO_2 Group 1 Trading Program), and 97.1030 through 97.1034 (CSAPR NOx Ozone Season Group 3 Trading Program) must submit to the Administrator a petition requesting approval of the alternative in accordance with 40 CFR 75.66 and 97.435 (CSAPR NOx Annual Trading Program), 97.635 (CSAPR SO_2 Group 1 Trading Program), and 97.1035 (CSAPR NOx Ozone Season Group 3 Trading Program). The Administrator's response approving or disapproving any petition for an alternative to a monitoring, recordkeeping, or reporting requirement is available on EPA's website at www.epa.gov/airmarkets/part-75-petition-responses.
(9VAC5-80-490 and 40 CFR 97)

72. **CSAPR –** The descriptions of monitoring applicable to a unit included above meet the requirement of 40 CFR 97.430 through 97.434 (CSAPR NOx Annual Trading Program), 97.630 through 97.634 (CSAPR SO_2 Group 1 Trading Program), and 97.1030 through 97.1034 (CSAPR NOx Ozone Season Group 3 Trading Program), and therefore minor permit modification procedures, in accordance with 40 CFR 70.7(e)(2)(i)(B) or 71.7(e)(1)(i)(B), may be used to add to or change the unit's monitoring system description.
(9VAC5-80-490 and 40 CFR 97)

CSAPR NOx Annual Trading Program requirements (40 CFR 97.406)

73. **CSAPR NOx Annual Trading Program** - The following conditions must be adhered to the combustion turbines (CT-1, CT-2, and CT-3), which are subject to the CSAPR NOx Annual Trading Program:

a. *Designated representative requirements*. - The owners and operators shall comply with the requirement to have a designated representative, and may have an alternate designated representative, in accordance with 40 CFR 97.413 through 97.418.

b. *Emissions monitoring, reporting, and recordkeeping requirements.*

i. The owners and operators, and the designated representative, of each CSAPR NOx Annual source and each CSAPR NOx Annual unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of 40 CFR 97.430 (general requirements, including installation, certification, and data accounting, compliance deadlines, reporting data, prohibitions, and long-term cold storage), 97.431 (initial monitoring system certification and recertification procedures), 97.432 (monitoring system out-of-control periods), 97.433 (notifications concerning monitoring), 97.434 (recordkeeping and reporting, including monitoring plans, certification applications, quarterly reports, and compliance certification), and 97.435 (petitions for alternatives to monitoring, recordkeeping, or reporting requirements).

ii. The emissions data determined in accordance with 40 CFR 97.430 through 97.435 shall be used to calculate allocations of CSAPR NOx Annual allowances under 40 CFR 97.411(a)(2) and (b) and 97.412 and to determine compliance with the CSAPR NOx Annual emissions limitation and assurance provisions under paragraph (c) below, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with 40 CFR 97.430 through 97.435 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

c. NOx emissions requirements.

i. CSAPR NOx Annual emissions limitation.

(1) As of the allowance transfer deadline for a control period in a given year, the owners and operators of each CSAPR NOx Annual source and each CSAPR NOx Annual unit at the source shall hold, in the source's compliance account, CSAPR NOx Annual allowances available for deduction for such control period under 40 CFR 97.424(a) in an amount not less than the tons of total NOx emissions for such control period from all CSAPR NOx Annual units at the source.

(2) If total NOx emissions during a control period in a given year from the CSAPR NOx Annual units at a CSAPR NOx Annual source are in excess of the CSAPR NOx Annual emissions limitation set forth in Condition 73.c.i(1) above, then:

a. The owners and operators of the source and each CSAPR NOx Annual unit at the source shall hold the CSAPR NOx Annual allowances required for deduction under 40 CFR 97.424(d); and

b. The owners and operators of the source and each CSAPR NOx Annual unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation of 40 CFR 97, subpart AAAAA and the Clean Air Act.

ii. CSAPR NOx Annual assurance provisions.

(1) If total NOx emissions during a control period in a given year from all CSAPR NOx Annual units at CSAPR NOx Annual sources in the state exceed the state assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative’s share of such NOx emissions during such control period exceeds the common designated representative’s assurance level for the state and such control period, shall hold (in the assurance account established for the owners and operators of such group) CSAPR NOx Annual allowances available for deduction for such control period under 40 CFR 97.425(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with 40 CFR 97.425(b), of multiplying -

a. The quotient of the amount by which the common designated representative’s share of such NOx emissions exceeds the common designated representative’s assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in the state for such control period, by which each common designated representative’s share of such NOx emissions exceeds the respective common designated representative’s assurance level; and

b. The amount by which total NOx emissions from all CSAPR NOx Annual units at CSAPR NOx Annual sources in the state for such control period exceed the state assurance level.

(2) The owners and operators shall hold the CSAPR NOx Annual allowances required under Condition 73.c.ii(1) above, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after such control period.

(3) Total NOx emissions from all CSAPR NOx Annual units at CSAPR NOx Annual sources in the state during a control period in a given year exceed the state assurance level if such total NOx emissions exceed the sum, for such control period, of the state NOx Annual trading budget under 40 CFR 97.410(a) and the state's variability limit under 40 CFR 97.410(b).

(4) It shall not be a violation of 40 CFR 97 Subpart AAAAA or of the Clean Air Act if total NOx emissions from all CSAPR NOx Annual units at CSAPR NOx Annual sources in a state during a control period exceed the state assurance level or if a common designated representative's share of total NOx emissions from the CSAPR NOx Annual units at CSAPR NOx Annual sources in the state during a control period exceeds the common designated representative's assurance level.

(5) To the extent the owners and operators fail to hold CSAPR NOx Annual allowances for a control period in a given year in accordance with Conditions 73.c.ii(1) through 73.c.ii(3) above,

a. The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and

b. Each CSAPR NOx Annual allowance that the owners and operators fail to hold for such control period in accordance with Conditions 73.c.ii(1) through 73.c.ii(3) above and each day of such control period shall constitute a separate violation of 40 CFR 97 Subpart AAAAA and the Clean Air Act.

iii. Compliance periods.

(1) A CSAPR NOx Annual unit shall be subject to the requirements under Condition 73.c.i above for the control period starting on the later of January 1, 2015, or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.430(b) and for each control period thereafter.

(2) A CSAPR NOx Annual unit shall be subject to the requirements under Condition 73.c.ii above for the control period starting on the later of January 1, 2017 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.430(b) and for each control period thereafter.

iv. Vintage of CSAPR NOx Annual allowances held for compliance.

(1) A CSAPR NOx Annual allowance held for compliance with the requirements under Condition 73.c.i(1) above for a control period in a given year must be a CSAPR NOx Annual allowance that was allocated or auctioned for such control period or a control period in a prior year.

(2) A CSAPR NOx Annual allowance held for compliance with the requirements under Conditions 73.c.i(2)a and 73.c.ii(1) through 73.c.ii(3) above for a control period in a given year must be a CSAPR NOx Annual allowance that was allocated or auctioned for a control period in a prior year or the control period in the given year or in the immediately following year.

v. *Allowance Management System requirements*. Each CSAPR NOx Annual allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with 40 CFR 97 Subpart AAAAA.

vi. *Limited authorization*. A CSAPR NOx Annual allowance is a limited authorization to emit one ton of NOx during the control period in one year. Such authorization is limited in its use and duration as follows:

(1) Such authorization shall only be used in accordance with the CSAPR NOx Annual Trading Program; and

(2) Notwithstanding any other provision of 40 CFR 97 Subpart AAAAA, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

vii. *Property right*. A CSAPR NOx Annual allowance does not constitute a property right.

d. Title V permit requirements.

i. No Title V permit revision shall be required for any allocation, holding, deduction, or transfer of CSAPR NOx Annual allowances in accordance with 40 CFR 97, Subpart AAAAA.

ii. A description of whether a unit is required to monitor and report NOx emissions using a continuous emissions monitoring system (under Subpart H of 40 CFR 75), an excepted monitoring system (under Appendices D and E to 40 CFR 75), a low mass emissions excepted monitoring methodology (under 40 CFR 75.19), or an alternative monitoring system (under Subpart E of 40 CFR 75) in accordance with 40 CFR 97.430 through 97.435 may be added to, or changed in, a Title V permit using minor permit modification procedures in accordance with 40 CFR 70.7(e)(2) and 71.7(e)(1), provided that the requirements applicable to the described monitoring and reporting (as added or changed, respectively) are already incorporated in such permit. This paragraph explicitly provides that the addition of, or change to, a unit's description as described in the prior sentence is eligible for minor permit modification procedures in accordance with 40 CFR 70.7(e)(2)(i)(B) and 71.7(e)(1)(i)(B).

e. Additional recordkeeping and reporting requirements.

i. Unless otherwise provided, the owners and operators of each CSAPR NOx Annual source and each CSAPR NOx Annual unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a period of five years from the date the document is created. This period may be extended for cause, at any time before the end of five years, in writing by the Administrator.

(1) The certificate of representation under 40 CFR 97.416 for the designated representative for the source and each CSAPR NOx Annual unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such five-year period until such certificate of representation and documents are superseded because of the submission of a new certificate of representation under 40 CFR 97.416 changing the designated representative.

(2) All emissions monitoring information, in accordance with 40 CFR 97 Subpart AAAAA.

(3) Copies of all reports, compliance certifications, and other submissions and all records made or required under, or to demonstrate compliance with the requirements of, the CSAPR NOx Annual Trading Program.

ii. The designated representative of a CSAPR NOx Annual source and each CSAPR NOx Annual unit at the source shall make all submissions required under the CSAPR NOx Annual Trading Program, except as provided in 40 CFR 97.418. This requirement does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a Title V operating permit program in 40 CFR 70 and 71.

f. Liability.

i. Any provision of the CSAPR NOx Annual Trading Program that applies to a CSAPR NOx Annual source or the designated representative of a CSAPR NOx Annual source shall also apply to the owners and operators of such source and of the CSAPR NOx Annual units at the source.

ii. Any provision of the CSAPR NOx Annual Trading Program that applies to a CSAPR NOx Annual unit or the designated representative of a CSAPR NOx Annual unit shall also apply to the owners and operators of such unit.

g. *Effect on other authorities*. No provision of the CSAPR NOx Annual Trading Program or exemption under 40 CFR 97.405 shall be construed as exempting or excluding the owners and operators, and the designated representative, of a CSAPR NOx Annual source or CSAPR NOx Annual unit from compliance with any other provision of the applicable, approved state implementation plan, a federally enforceable permit, or the Clean Air Act.

(9VAC5-80-490 and 40 CFR 97.406)

CSAPR SO_2 Group 1 Trading Program requirements (40 CFR 97.606)

74. **CSAPR SO_2 Group 1 Trading Program -** The following conditions must be adhered to the combustion turbines (CT-1, CT-2, and CT-3), which are subject to the CSAPR SO_2 Group 1 Trading Program:

a. *Designated representative requirements*. The owners and operators shall comply with the requirement to have a designated representative, and may have an alternate designated representative, in accordance with 40 CFR 97.613 through 97.618.

b. Emissions monitoring, reporting, and recordkeeping requirements.

i. The owners and operators, and the designated representative, of each CSAPR SO_2 Group 1 source and each CSAPR SO_2 Group 1 unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of 40 CFR 97.630 (general requirements, including installation, certification, and data accounting, compliance deadlines, reporting data, prohibitions, and long-term cold storage), 97.631 (initial monitoring system certification and recertification procedures), 97.632 (monitoring system out-of-control periods), 97.633 (notifications concerning monitoring), 97.634 (recordkeeping and reporting, including monitoring plans, certification applications, quarterly reports, and compliance certification), and 97.635 (petitions for alternatives to monitoring, recordkeeping, or reporting requirements).

ii. The emissions data determined in accordance with 40 CFR 97.630 through 97.635 shall be used to calculate allocations of CSAPR SO_2 Group 1 allowances under 40 CFR 97.611(a)(2) and (b) and 97.612 and to determine compliance with the CSAPR SO_2 Group 1 emissions limitation and assurance provisions under Condition 74.c below, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with 40 CFR 97.630 through 97.635 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

c. SO_2 emissions requirements.

i. CSAPR SO_2 Group 1 emissions limitation.

(1) As of the allowance transfer deadline for a control period in a given year, the owners and operators of each CSAPR SO_2 Group 1 source and each CSAPR SO_2 Group 1 unit at the source shall hold, in the source's compliance account, CSAPR SO_2 Group 1 allowances available for deduction for such control period under 40 CFR 97.624(a) in an amount not less than the tons of total SO_2 emissions for such control period from all CSAPR SO_2 Group 1 units at the source.

(2) If total SO_2 emissions during a control period in a given year from the CSAPR SO_2 Group 1 units at a CSAPR SO_2 Group 1 source are in excess of the CSAPR SO_2 Group 1 emissions limitation set forth in Condition 74.c.i(1) above, then:

a. The owners and operators of the source and each CSAPR SO_2 Group 1 unit at the source shall hold the CSAPR SO_2 Group 1 allowances required for deduction under 40 CFR 97.624(d); and

b. The owners and operators of the source and each CSAPR SO_2 Group 1 unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation 40 CFR 97 Subpart CCCCC and the Clean Air Act.

ii. CSAPR SO_2 Group 1 assurance provisions.

(1) If total SO_2 emissions during a control period in a given year from all CSAPR SO_2 Group 1 units at CSAPR SO_2 Group 1 sources in the state exceed the state assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative's share of such SO_2 emissions during such control period exceeds the common designated representative's assurance level for the state and such control period, shall hold (in the assurance account established for the owners and operators of such group) CSAPR SO_2 Group 1 allowances available for deduction for such control period under 40 CFR 97.625(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with 40 CFR 97.625(b), of multiplying -

a. The quotient of the amount by which the common designated representative's share of such SO_2 emissions exceeds the common designated representative's assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in the state for such control period, by which each common designated representative's share of such SO_2 emissions exceeds the respective common designated representative's assurance level; and

b. The amount by which total SO_2 emissions from all CSAPR SO_2 Group 1 units at CSAPR SO_2 Group 1 sources in the state for such control period exceed the state assurance level.

(2) The owners and operators shall hold the CSAPR SO_2 Group 1 allowances required under Condition 74.c.ii(1) above, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after the year of such control period.

(3) Total SO_2 emissions from all CSAPR SO_2 Group 1 units at CSAPR SO_2 Group 1 sources in the state during a control period in a given year exceed the state assurance level if such total SO_2 emissions exceed the sum, for such control period, of the state SO_2 Group 1 trading budget under 40 CFR 97.610(a) and the state's variability limit under 40 CFR 97.610(b).

(4) It shall not be a violation of 40 CFR 97 Subpart CCCCC or of the Clean Air Act if total SO_2 emissions from all CSAPR SO_2 Group 1 units at CSAPR SO_2 Group 1 sources in the state during a control period exceed the state assurance level or if a common designated representative's share of total SO_2 emissions from the CSAPR SO_2 Group 1 units at CSAPR SO_2 Group 1 sources in the state during a control period exceeds the common designated representative's assurance level.

(5) To the extent the owners and operators fail to hold CSAPR SO_2 Group 1 allowances for a control period in a given year in accordance with Conditions 74.c.ii(1) through 74.c.ii(3) above,

a. The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and

b. Each CSAPR SO_2 Group 1 allowance that the owners and operators fail to hold for such control period in accordance with Conditions 74.c.ii(1) through 74.c.ii(3) above and each day of such control period shall constitute a separate violation of 40 CFR 97 Subpart CCCCC and the Clean Air Act.

iii. Compliance periods.

(1) A CSAPR SO_2 Group 1 unit shall be subject to the requirements under Condition 74.c.i above for the control period starting on the later of January 1, 2015, or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.630(b) and for each control period thereafter.

(2) A CSAPR SO_2 Group 1 unit shall be subject to the requirements under Condition 74.c.ii above for the control period starting on the later of January 1, 2017, or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.630(b) and for each control period thereafter.

iv. Vintage of CSAPR SO_2 Group 1 allowances held for compliance.

(1) A CSAPR SO_2 Group 1 allowance held for compliance with the requirements under Condition 74.c.i(1) above for a control period in a given year must be a CSAPR SO_2 Group 1 allowance that was allocated or auctioned for such control period or a control period in a prior year.

(2) A CSAPR SO_2 Group 1 allowance held for compliance with the requirements under Conditions 74.c.i(2)a and 74.c.ii(1) through 74.c.ii(3) above for a control period in a given year must be a CSAPR SO_2 Group 1 allowance that was allocated or auctioned for a control period in a prior year or the control period in the given year or in the immediately following year.

v. *Allowance Management System requirements*. Each CSAPR SO_2 Group 1 allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with 40 CFR 97 Subpart CCCCC.

vi. *Limited authorization*. A CSAPR SO_2 Group 1 allowance is a limited authorization to emit one ton of SO_2 during the control period in one year. Such authorization is limited in its use and duration as follows:

(1) Such authorization shall only be used in accordance with the CSAPR SO_2 Group 1 Trading Program; and

(2) Notwithstanding any other provision of 40 CFR 97 Subpart CCCCC, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

vii. *Property right*. A CSAPR SO_2 Group 1 allowance does not constitute a property right.

d. Title V permit requirements.

i. No Title V permit revision shall be required for any allocation, holding, deduction, or transfer of CSAPR SO_2 Group 1 allowances in accordance with 40 CFR 97 Subpart CCCCC.

ii. A description of whether a unit is required to monitor and report SO_2 emissions using a continuous emission monitoring system (under subpart B of 40 CFR 75), an excepted monitoring system (under appendices D and E to 40 CFR 75), a low mass emissions excepted monitoring methodology (under 40 CFR 75.19), or an alternative monitoring system (under Subpart E of 40 CFR 75) in accordance with 40 CFR 97.630 through 97.635 may be added to, or changed in, a Title V permit using minor permit modification procedures in accordance with 40 CFR 70.7(e)(2) and 71.7(e)(1), provided that the requirements applicable to the described monitoring and reporting (as added or changed, respectively) are already incorporated in such permit. This paragraph explicitly provides that the addition of, or change to, a unit's description as described in the prior sentence is eligible for minor permit modification procedures in accordance with 40 CFR 70.7(e)(2)(i)(B) and 71.7(e)(1)(i)(B).

e. Additional recordkeeping and reporting requirements.

i. Unless otherwise provided, the owners and operators of each CSAPR SO_2 Group 1 source and each CSAPR SO_2 Group 1 unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a period of five years from the date the document is created. This period may be extended for cause, at any time before the end of five years, in writing by the Administrator.

(1) The certificate of representation under 40 CFR 97.616 for the designated representative for the source and each CSAPR SO_2 Group 1 unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such five-year period until such certificate of representation and documents are superseded because of the submission of a new certificate of representation under 40 CFR 97.616 changing the designated representative.

(2) All emissions monitoring information, in accordance with 40 CFR 97 Subpart CCCCC.

(3) Copies of all reports, compliance certifications, and other submissions and all records made or required under, or to demonstrate compliance with the requirements of, the CSAPR SO_2 Group 1 Trading Program.

ii. The designated representative of a CSAPR SO_2 Group 1 source and each CSAPR SO_2 Group 1 unit at the source shall make all submissions required under the CSAPR SO_2 Group 1 Trading Program, except as provided in 40 CFR 97.618. This requirement does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a Title V operating permit program in 40 CFR 70 and 71.

f. Liability.

i. Any provision of the CSAPR SO_2 Group 1 Trading Program that applies to a CSAPR SO_2 Group 1 source or the designated representative of a CSAPR SO_2 Group 1 source shall also apply to the owners and operators of such source and of the CSAPR SO_2 Group 1 units at the source.

ii. Any provision of the CSAPR SO_2 Group 1 Trading Program that applies to a CSAPR SO_2 Group 1 unit or the designated representative of a CSAPR SO_2 Group 1 unit shall also apply to the owners and operators of such unit.

g. *Effect on other authorities*. No provision of the CSAPR SO_2 Group 1 Trading Program or exemption under 40 CFR 97.605 shall be construed as exempting or excluding the owners and operators, and the designated representative, of a CSAPR SO_2 Group 1 source or CSAPR SO_2 Group 1 unit from compliance with any other provision of the applicable, approved state implementation plan, a federally enforceable permit, or the Clean Air Act.

(9VAC5-80-490 and 40 CFR 97.606)

CSAPR NOx Ozone Season Group 3 Trading Program requirements (40 CFR 97.1006)

75. **CSAPR NOx Ozone Season Group 3 Trading Program -** The following conditions must be adhered to the combustion turbines (CT-1, CT-2, and CT-3), which are subject to the CSAPR NOx Group 3 Trading Program.

a. *Designated representative requirements*. The owners and operators shall comply with the requirement to have a designated representative, and may have an alternate designated representative, in accordance with 40 CFR 97.1013 through 97.1018.

b. Emissions monitoring, reporting, and recordkeeping requirements.

i. The owners and operators, and the designated representative, of each CSAPR NOx Ozone Season Group 3 source and each CSAPR NOx Ozone Season Group 3 unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of 40 CFR 97.1030 (general requirements, including installation, certification, and data accounting, compliance deadlines, reporting data, prohibitions, and long-term cold storage), 97.1031 (initial monitoring system certification and recertification procedures), 97.1032 (monitoring system out-of-control periods), 97.1033 (notifications concerning monitoring), 97.1034 (recordkeeping and reporting, including monitoring plans, certification applications, quarterly reports, and compliance certification), and 97.1035 (petitions for alternatives to monitoring, recordkeeping, or reporting requirements).

ii. The emissions data determined in accordance with 40 CFR 97.1030 through 97.1035 shall be used to calculate allocations of CSAPR NOx Ozone Season Group 3 allowances under 40 CFR 97.1011(a)(2) and (b) and 97.1012 and to determine compliance with the CSAPR NOx Ozone Season Group 3 emissions limitation and assurance provisions under Condition 75.c below, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with 40 CFR 97.1030 through 97.1035 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

c. NOx emissions requirements.

i. CSAPR NOx Ozone Season Group 3 emissions limitation.

(1) As of the allowance transfer deadline for a control period in a given year, the owners and operators of each CSAPR NOx Ozone Season Group 3 source and each CSAPR NOx Ozone Season Group 3 unit at the source shall hold, in the source's compliance account, CSAPR NOx Ozone Season Group 3 allowances available for deduction for such control period under 40 CFR 97.1024(a) in an amount not less than the tons of total NOx emissions for such control period from all CSAPR NOx Ozone Season Group 3 units at the source.

(2) If total NOx emissions during a control period in a given year from the CSAPR NOx Ozone Season Group 3 units at a CSAPR NOx Ozone Season Group 3 source are in excess of the CSAPR NOx Ozone Season Group 3 emissions limitation set forth in Condition 75.c.i(1) above, then:

a. The owners and operators of the source and each CSAPR NOx Ozone Season Group 3 unit at the source shall hold the CSAPR NOx Ozone Season Group 3 allowances required for deduction under 40 CFR 97.1024(d); and

b. The owners and operators of the source and each CSAPR NOx Ozone Season Group 3 unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation 40 CFR 97 Subpart GGGGG and the Clean Air Act.

ii. CSAPR NOx Ozone Season Group 3 assurance provisions.

(1) If total NOx emissions during a control period in a given year from all base CSAPR NOx Ozone Season Group 3 units at base CSAPR NOx Ozone Season Group 3 sources in a state exceed the state assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative's share of such NOx emissions during such control period exceeds the common designated representative's assurance level for the state and such control period, shall hold (in the assurance account established for the owners and operators of such group) CSAPR NOx Ozone Season Group 3 allowances available for deduction for such control period under 40 CFR 97.1025(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with 40 CFR 97.1025(b), of multiplying -

a. The quotient of the amount by which the common designated representative's share of such NOx emissions exceeds the common designated representative's assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in the state for such control period, by which each common designated representative's share of such NOx emissions exceeds the respective common designated representative's assurance level; and

b. The amount by which total NOx emissions from all base CSAPR NOx Ozone Season Group 3 units at base CSAPR NOx Ozone Season Group 3 sources in the state for such control period exceed the state assurance level.

(2) The owners and operators shall hold the CSAPR NOx Ozone Season Group 3 allowances required under Condition 75.c.ii(1) above, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after the year of such control period.

(3) Total NOx emissions from all base CSAPR NOx Ozone Season Group 3 units at base CSAPR NOx Ozone Season Group 3 sources in a state during a control period in a given year exceed the state assurance level if such total NOx emissions exceed the sum, for such control period, of the state NOx Ozone Season Group 3 trading budget under 40 CFR 97.1010(a) and the state's variability limit under 40 CFR 97.1010(b).

(4) It shall not be a violation of 40 CFR 97 Subpart GGGGG or of the Clean Air Act if total NOx emissions from all base CSAPR NOx Ozone Season Group 3 units at base CSAPR NOx Ozone Season Group 3 sources in a state during a control period exceed the state assurance level or if a common designated representative's share of total NOx emissions from the base CSAPR NOx Ozone Season Group 3 units at base CSAPR NOx Ozone Season Group 3 sources in the state during a control period exceeds the common designated representative's assurance level.

(5) To the extent the owners and operators fail to hold CSAPR NOx Ozone Season Group 3 allowances for a control period in a given year in accordance with Conditions 75.c.ii(1) through 75.c.ii(3) above,

a. The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and

b. Each CSAPR NOx Ozone Season Group 3 allowance that the owners and operators fail to hold for such control period in accordance with Conditions 75.c.ii(1) through 75.c.ii(3) above and each day of such control period shall constitute a separate violation of 40 CFR 97 Subpart GGGGG and the Clean Air Act.

iii. Compliance periods.

(1) A CSAPR NOx Ozone Season Group 3 unit shall be subject to the requirements under Condition 75.c.i above for the control period starting on the later of May 1, 2021, or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.30(b) and for each control period thereafter.

(2) A base CSAPR NOx Ozone Season Group 3 unit shall be subject to the requirements under Condition 75.c.ii above for the control period starting on the later of May 1, 2021 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.1030(b) and for each control period thereafter.

iv. Vintage of CSAPR NOx Ozone Season Group 3 allowances held for compliance.

(1) A CSAPR NOx Ozone Season Group 3 allowance held for compliance with the requirements under Condition 75.c.i(1) above for a control period in a given year must be a CSAPR NOx Ozone Season Group 3 allowance that

was allocated or auctioned for such control period or a control period in a prior year.

(2) A CSAPR NOx Ozone Season Group 3 allowance held for compliance with the requirements under Conditions 75.c.i(2)a and 75.c.ii(1) through 75.c.ii(3) above for a control period in a given year must be a CSAPR NOx Ozone Season Group 3 allowance that was allocated or auctioned for a control period in a prior year or the control period in the given year or in the immediately following year.

v. *Allowance Management System requirements*. Each CSAPR NOx Ozone Season Group 3 allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with 40 CFR 97 Subpart GGGGG.

vi. *Limited authorization*. A CSAPR NOx Ozone Season Group 3 allowance is a limited authorization to emit one ton of NOx during the control period in one year. Such authorization is limited in its use and duration as follows:

(1) Such authorization shall only be used in accordance with the CSAPR NOx Ozone Season Group 3 Trading Program; and

(2) Notwithstanding any other provision of 40 CFR 97 Subpart GGGGG, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

vii. *Property right*. A CSAPR NOx Ozone Season Group 3 allowance does not constitute a property right.

d. Title V permit requirements.

i. No Title V permit revision shall be required for any allocation, holding, deduction, or transfer of CSAPR NOx Ozone Season Group 3 allowances in accordance with 40 CFR 97 Subpart GGGGG.

ii. A description of whether a unit is required to monitor and report NOx emissions using a continuous emission monitoring system (under Subpart H of 40 CFR 75), an excepted monitoring system (under Appendices D and E to 40 CFR 75), a low mass emissions excepted monitoring methodology (under 40 CFR 75.19), or an alternative monitoring system (under Subpart E of 40 CFR 75) in accordance with 40 CFR 97.1030 through 97.1035 may be added to, or changed in, a Title V permit using minor permit modification procedures in accordance with 40 CFR

70.7(e)(2) and 71.7(e)(1), provided that the requirements applicable to the described monitoring and reporting (as added or changed, respectively) are already incorporated in such permit. This paragraph explicitly provides that the addition of, or change to, a unit's description as described in the prior sentence is eligible for minor permit modification procedures in accordance with 40 CFR 70.7(e)(2)(i)(B) and 71.7(e)(1)(i)(B).

e. Additional recordkeeping and reporting requirements.

i. Unless otherwise provided, the owners and operators of each CSAPR NOx Ozone Season Group 3 source and each CSAPR NOx Ozone Season Group 3 unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a period of five years from the date the document is created. This period may be extended for cause, at any time before the end of five years, in writing by the Administrator.

(1) The certificate of representation under 40 CFR 97.1016 for the designated representative for the source and each CSAPR NOx Ozone Season Group 3 unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such five-year period until such certificate of representation and documents are superseded because of the submission of a new certificate of representation under 40 CFR 97.1016 changing the designated representative.

(2) All emissions monitoring information, in accordance with 40 CFR 97 Subpart GGGGG.

(3) Copies of all reports, compliance certifications, and other submissions and all records made or required under, or to demonstrate compliance with the requirements of, the CSAPR NOx Ozone Season Group 3 Trading Program.

ii. The designated representative of a CSAPR NOx Ozone Season Group 3 source and each CSAPR NOx Ozone Season Group 3 unit at the source shall make all submissions required under the CSAPR NOx Ozone Season Group 3 Trading Program, except as provided in 40 CFR 97.1018. This requirement does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a Title V operating permit program in 40 CFR 70 and 71.

f. Liability.

i. Any provision of the CSAPR NOx Ozone Season Group 3 Trading Program that applies to a CSAPR NOx Ozone Season Group 3 source or the designated representative of a CSAPR NOx Ozone Season Group 3 source shall also apply to the owners and operators of such source and of the CSAPR NOx Ozone Season Group 3 units at the source.

ii. Any provision of the CSAPR NOx Ozone Season Group 3 Trading Program that applies to a CSAPR NOx Ozone Season Group 3 unit or the designated representative of a CSAPR NOx Ozone Season Group 3 unit shall also apply to the owners and operators of such unit.

g. *Effect on other authorities.* No provision of the CSAPR NOx Ozone Season Group 3 Trading Program or exemption under 40 CFR 97.1005 shall be construed as exempting or excluding the owners and operators, and the designated representative, of a CSAPR NOx Ozone Season Group 3 source or CSAPR NOx Ozone Season Group 3 unit from compliance with any other provision of the applicable, approved state implementation plan, a federally enforceable permit, or the Clean Air Act.

(9VAC5-80-490 and 40 CFR 97.1006)

Commonwealth of Virginia

VIRGINIA DEPARTMENT OF ENVIRONMENTAL QUALITY

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STATEMENT OF LEGAL AND FACTUAL BASIS

Virginia Electric and Power Company
Dominion – Elizabeth River Combustion Turbine Station
Chesapeake, Virginia
Permit No. TRO – 61108

Title V of the 1990 Clean Air Act Amendments required each state to develop a permit program to ensure that certain facilities have federal Air Pollution Operating Permits, called Title V Operating Permits. As required by 40 CFR Part 70 and 9VAC5 Chapter 80, Virginia Electric and Power Company has applied for a Title V Operating Permit for its Chesapeake City facility. The Department has reviewed the application and has prepared a draft Title V Operating Permit.

Permit Writer: ______________________ Date: **February 1, 2023**
Mayanni McCourty
(757) 647-9026

Air Permit Manager: ______________________ Date: **February 1, 2023**
Mariama Ouedraogo

Regional Director: ______________________ Date: **February 1, 2023**
Janet F. Weyland
Deputy Regional Director

FACILITY INFORMATION

Permittee
Virginia Electric and Power Company
DBA: Dominion – Elizabeth River Combustion Turbine (CT) Station
120 Tredegar Street
Richmond, VA 23219

Facility
Dominion – Elizabeth River CT Station
2837 South Military Highway
Chesapeake, VA 23323

County-Plant Identification Number: 51-550-00161

FACILITY DESCRIPTION

NAICS Code: 221112 – Fossil Fuel Electric Power Generation

The Dominion – Elizabeth River Combustion Turbine (CT) Station is an electric power generation facility. The facility consists of three Westinghouse W501D5 simple cycle gas turbines (CT1-A&B, CT2-A&B, CT3-A&B) that combust both natural gas and distillate oil (fuel oil #2) to generate electricity. The turbines were manufactured and constructed in 1991 and utilize water injection for NOx control. The turbines are low mass emissions (LME) units as defined in 40CFR72.2. As specified in 40CFR75.19, the turbines use optional NOx emission estimation procedures in lieu of continuous NOx emissions monitoring systems to determine NOx emissions. In addition to the electric generating turbines, the facility currently operates a small gasoline dispensing operation that is subject to the requirements of 40 CFR 63 Subpart CCCCCC, as well as the following insignificant emission units: fuel oil valves, pumps, and flanges (IL-2) and turbine lube oil venting (IL-5).

The Dominion – Elizabeth River CT Station is a Title V major source for CO, NOx, and SO_2 pollutants. The source is located in Chesapeake City, which is an attainment area for all air pollutants and is a Prevention of Significant Deterioration (PSD) source under 9VAC5-80 Article 8 of the Virginia Regulations. The facility is currently permitted under a PSD Permit issued on March 5, 1991 and amended on November 28, 2005, June 13, 2007, and April 10, 2008.

The facility is currently subject to the provisions of the Acid Rain Program (ARP) and the requirements of the Cross State Air Pollution Rule (CSAPR) for NOx and SO_2 pollutants. The ARP, based on Title IV (Acid Rain) of the Clean Air Act, applies to fossil-fuel-fired electric generating units (EGUs) having a capacity greater than 25 MW. The CSAPR requires certain states (including the Commonwealth of Virginia) to significantly improve air quality by reducing power plant emissions that contribute to ozone and/or fine particle pollution in other states. The facility submitted a renewal application for the Title IV Acid Rain Permit dated June 22, 2016.

The requirements of the CSAPR Program and the Acid Rain Program are incorporated in the federal operating permit.

The facility had also applied for a CO_2 budget trading program permit, which was issued on March 10, 2021 as a State Operating Permit (SOP). Due to all of the permit requirements being state-only enforceable, the Article 3 permit for the facility does not contain CO_2 budget permit requirements.

COMPLIANCE STATUS

A full compliance evaluation of this facility, including a site visit, was most recently conducted on February 16, 2021. All reports and other data required by permit conditions or regulations, which are submitted to DEQ, have been evaluated for compliance. Based on these compliance evaluations, the facility has not been found to be in violation of any state or federal applicable requirements at this time.

EMISSION UNITS

Please refer to the Emission Units table in the Article 3 permit on Page 6 and 7.

EMISSIONS INVENTORY

Emissions from the facility in 2021 are summarized in the following tables. The annual emissions are derived from the 2021 CEDs emission report. A copy of the report and information submitted by the facility are included as Attachment A.

2021 Criteria Pollutant and Greenhouse Gas Emissions in Tons/Year

Emissions	VOC	CO	SO_2	PM10	PM2.5	NOx
Total	0.2	4.9	4.9	2.3	2.3	49.2

2021 Facility Hazardous Air Pollutant (HAP) Emissions

Pollutant	2021 Hazardous Air Pollutant Emission in Tons/Yr
Sulfuric Acid Mist (H_2SO_4)	0.95
Formaldehyde (FORM)	0.16
Lead (PB)	0
Beryllium Compounds (BEC)	0

FUEL BURNING EQUIPMENT REQUIREMENTS - (Turbines CT-1, CT-2, and CT-3)

Citations

The following citations from the Virginia Administrative Codes identify the underlying authorities to implement the specific requirements determined to be applicable in the permit:

9VAC5 Chapter 80, Article 1 - Federal Operating Permits

9VAC5 Chapter 80, Article 2 - Permit Program Fees

9VAC5 Chapter 80, Article 3 - Acid Rain

9VAC5 Chapter 80, Article 4 - Insignificant Activities

9VAC5 Chapter 80, Article 6 - Permits for New and Modified Sources

9VAC5 Chapter 80, Article 8 - Prevention of Significant Deterioration

9VAC5 Chapter 50 New and Modified Stationary Sources, Part 1, Special Provisions

9VAC5 Chapter 50 Article 4: Standards of Performance for Stationary Sources

9VAC5 Chapter 50 Article 5: EPA Standards of Performance for New Stationary Sources

The following federal regulations have been determined to be applicable:

40 CFR Part 60 Subpart GG - Standards of Performance for Stationary Gas Turbines.
40 CFR Part 68 - Chemical Accident Prevention Provisions
40 CFR Part 75 Section 75.19 - Optional SO_2, NO_x, and CO_2 emissions calculation for low mass emissions (LME) units.
40 CFR Part 82 - Protection of Stratospheric Ozone
40 CFR Part 97 - NO_x Budget Trading Program and CSAPR NO_x and SO_2 Trading Programs
40 CFR Part 98 - Mandatory Greenhouse Gas Reporting

Limitations

The following limitations are state BACT requirements from the PSD permit issued on March 5, 1991 and amended on November 28, 2005, June 13, 2007, and April 10, 2008. The condition numbers below are from the PSD permit; a copy of the permit is enclosed in Attachment B.

Condition 4: Nitrogen dioxide (NOx) emissions from each turbine (CT-1, CT-2, and CT-3) shall be controlled by the use of water injection.

Condition 6: Each turbine shall be operated at not less than 85% and not greater than 100% of rated capacity, with the exception of startup, shutdown and no load testing.

Condition 7: The three turbines (combined) shall not operate more than 6,000 hours per year, and no single unit shall operate for more than 2,500 hours per year.

Condition 8: The approved fuels for the turbines are No. 2 fuel oil and natural gas.

Condition 9: The three turbines (combined) shall consume no more than 59.6 x 10^6 gallons of No. 2 fuel oil (distillate oil) and 9,000 x 10^6 cubic feet of natural gas per year.

Condition 10: The No. 2 fuel oil shall meet the maximum sulfur content of 0.2% by weight and 0.05% nitrogen content by weight and the natural gas shall meet the maximum sulfur content of 0.06% by weight (20 grains/100 standard cubic feet). The condition is more stringent than the applicable NSPS Subpart GG requirements; the NSPS citations have been included in this condition.

Condition 11: The condition establishes fuel certification requirements for Pipeline No. 2 Fuel Oil and Natural Gas. The condition is more stringent than the applicable NSPS Subpart GG requirements; the NSPS citations have been included in this condition.

Condition 12: The condition establishes the hourly and annual emission limitations for PM, PM10, NOx, CO, VOC, H_2SO4, and Beryllium. The condition is more stringent than the applicable NSPS Subpart GG requirements; the NSPS citations have been included in this condition.

Condition 13: The condition establishes the visible emission limitation for each combined-cycle (CT-1, CT-2, and CT-3).

Condition 14: The condition establishes guidelines for visible emission observations (VEO).

In addition to the limitations provided by the PSD Permit and Virginia Administrative Code, the combined-cycle units (CT-1, CT-2, and CT-3) are subject to 40 CFR 60 Subpart GG (Standards of Performance for Stationary Gas Turbines).

The provisions of Subpart GG apply to stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules (10 million Btu) per hour, based on the lower heating value of the fuel fired, and that commenced construction, modification, or reconstruction after October 3, 1977. NSPS Subpart GG establishes NOx and SO_2 limitations as described in 40 CFR 60.332 and 60.333. Applicable NSPS Subpart GG requirements are included in the Title V permit as streamlined conditions. The regulatory citations for the NSPS are included with the applicable PSD permit requirements in the Article 3 permit. A discussion of the streamlined requirements are provided in the Streamlined Requirements section below.

Monitoring

The following monitoring requirements are from the PSD permit issued on March 5, 1991 and amended on November 28, 2005, June 13, 2007, and April 10, 2008. The condition numbers below are from the PSD permit; a copy of the permit is enclosed in Attachment B.

Condition 5: Each turbine shall be equipped with a device to continuously monitor and record the fuel consumption, water injection and the ratio of water to fuel being fired in the turbine. The condition is more stringent than the applicable NSPS Subpart GG requirements; the NSPS citations have been included in the condition.

Condition 14: The permit establishes the Visible Emissions Observation schedule for each of the turbines.

The requirement to install and continuously monitor and record the water injection, and ratio of water to fuel being fired, provides a means of demonstrating continuous compliance of the water injection control requirements for minimizing NOx emissions. The recordkeeping section below requires the facility to keep records of one-hour averages of the fuel to water ratio.

The device to monitor and record the fuel consumption for each turbine, required by the permit, provides a means of demonstrating continuous compliance with the fuel throughput limitations for each unit, as well as the combined fuel limitations. Additionally, the fuel usage provided by each monitor provides a means of calculating emissions; emissions from each turbine are calculated using the following information:

Table 1: Calculation Methods

Pollutant	**Distillate Oil Lb/MMBtu – Fuel Input**	**Source**	**Natural Gas Lb/MMBtu – Fuel Input**	**Source**
PM-10	0.012	AP-42, Table 3.1-2a	0.0066	AP-42, Table 3.1-2a
PM-2.5	0.012	AP-42, Table 3.1-2a	0.0066	AP-42, Table 3.1-2a
VOC	0.0015	Stack Testing	0.0004	Stack Testing

Pollutant	**Distillate Oil Lb/MMBtu – Fuel Input**	**Source**	**Natural Gas Lb/MMBtu – Fuel Input**	**Source**
CO	0.006	Stack Testing	0.024	Stack Testing
NOx	--	40 CFR Part 75 LME data	--	40 CFR Part 75 LME data
SO_2	--	40 CFR Part 75 LME data	--	40 CFR Part 75 LME data

In addition to the calculation methods specified above, the permit also requires stack testing to demonstrate compliance for emissions of NOx, CO, and VOC. The stack testing requirements for the turbines are addressed in the Testing section below. The most recent stack tests were conducted on Unit 2 on March 3, 2022 and March 16, 2022 (distillate oil and natural gas, respectfully) and on Unit 3 on February 28, 2022 and June 7-9, 2022 (distillate oil and natural gas, respectfully).

The turbines qualify as low mass emissions (LME) units and use the LME excepted methodology in 40 CFR 75.19 to calculate NOx and SO_2 emissions in lieu of continuous emission monitoring systems. This methodology is used to demonstrate compliance for emissions of NOx and SO_2.

The permit establishes a visible emissions observation (VEO) schedule as follows:

Table 2: Visible Emission Frequencies

Operating Schedule/History	**Observation Frequency**
< 20 hrs / year with no OV Testing	No Observations Required
< 20 hrs / year with OV* Testing	Once per year
20 hrs/yr < hours operated < 200 hrs/yr	Once per year
Hours operated > 200 hrs/yr	Once every 200 hours

* OV testing means Operability Verification testing. Operability Verification testing refers to any periodic tests conducted by the source to assure that the combustion turbines could be put into operation if needed. A visible emissions observation can only be conducted when the combustion turbines are operating at a normal load, which is between 85 and 100 percent.

Each VEO shall be performed for a sufficient period of time (minimum of 6 minutes) to identify the presence of visible emissions. If visible emissions are observed, a Method 9-certified observer shall conduct a VEO. If visible emissions do not appear to exceed 10% opacity, no action shall be required. However, if the observed visible emissions appear to exceed 10% opacity, a visible emission evaluation (VEE) shall be conducted using 40 CFR Part 60, Appendix A, Method 9, for a period of not less than 6 minutes. If the average opacity exceeds 10%, modifications and/or repairs shall be performed to correct the problem. Once the problem is corrected another 6 minute VEE shall be performed to prove that the corrective action taken was effective.

The VEO schedule, as described above, along with the corrective actions, provides a means of demonstrating continuous compliance with the visible emission limitations in the permit.

In addition to the monitoring requirements discussed above, the permit requires the facility to develop and maintain a Parameter Monitoring Plan in accordance with 40 CFR 60.334(g).

Recordkeeping

General Title V retention of records is 5 years. Some of the records required of the applicable NSPS have 2-year retention timeframes. For the purpose of Titles IV and V, all records relevant to this permit and facility must be maintained for 5 years.

The permit includes requirements for maintaining records of all monitoring and testing required by the permit. These records include the following:

- one-hour averages of the water to fuel ratio,
- operating rate (load rate),
- annual hours of operation of each of the combustion turbines, and the combined number of hours of the combustion turbines,
- annual throughput of No. 2 fuel oil, and annual throughput of natural gas,
- fuel analyses/certifications,
- parameter monitoring plan,
- records of VEO and VEE logs,
- monthly and annual NOx emissions (in pounds or tons) from the operation of the three gas turbines (combined), and
- A description of method used to calculate NOx emissions.

Records of the one-hour averages of the water to fuel ratio for each turbine provide a means of demonstrating continuous compliance with the water injection control requirements for minimizing NOx emissions. The monitoring requirements for the water to fuel ratio are discussed in the monitoring section above.

Records of the operating load provide a means of demonstrating compliance with the permit limitation for the operating load. The operating load is limited to not less than 85% and not greater than 100% of rated capacity, with the exception of startup, shutdown, fuel transfer, and no load testing. The operating rate shall be calculated for each clock hour as an arithmetic average of all valid 2-minute readings (readings during startup or shutdown are not considered valid). 100% rated capacity is defined as the maximum load achievable given ambient weather and gas turbine performance conditions.

The combustion turbines are equipped with fuel consumption monitoring devices, as discussed in the Monitoring section above. The monitoring and recordkeeping requirements regarding fuel consumption for each combustion turbine provides a means of demonstrating continuous compliance with the fuel throughput limitations provided in the permit. In addition, the fuel consumption monitoring provides a means of calculating, and demonstrating compliance with, the emission limitations provided in the permit. Calculation methods are provided in the monitoring section above.

The fuel analyses and certifications require the facility to sample the distillate oil in the fuel tanks, as well as receive certification regarding the sulfur content of the distillate oil. The fuel certifications for natural gas require the facility to determine the sulfur content of the natural gas through one of the means specified in the permit. The fuel certifications provide a means of demonstrating continuous compliance with the fuel sulfur limitations contained in the permit, as well as a means to calculate the sulfur dioxide emissions. Sulfur dioxide emissions are related to the fuel-bound sulfur in the fuel, and the sulfur content of the fuel, in addition to the fuel consumption, provide a means of calculating sulfur dioxide emissions, as well as determining continuous compliance with the emission limitations.

<u>Testing</u>

The following testing requirements are from the PSD permit issued on March 5, 1991 and amended on November 28, 2005, June 13, 2007, and April 10, 2008. The condition numbers below are from the PSD permit; a copy of the permit is enclosed in Attachment B.

Condition 16: The condition establishes the requirements and time frames for stack testing and visible emission evaluation (VEE) for NOx, CO, and VOCs. Upon DEQ request, the permittee shall conduct additional performance tests for NOx (by methods referenced in 40 CFR Part 60, Subpart GG), CO (by method 10 or 10B) and VOC (by method pre-approved by DEQ in protocol) from the turbines (as specified below) to demonstrate compliance with the emission limits contained in this permit. Data from the monitoring of water to fuel ratio obtained during the test must be included in the stack test emission report. Two of the three gas turbines shall be tested during each five-year Title V permit term (beginning in November of 2005). The testing shall take place within the first 24 months of each Title V permit term. Each turbine shall be tested at least once every other testing cycle.

The stack testing requirements for NOx, CO, and VOC provide a means of demonstrating compliance with the emission limitations provided in the permit. Stack testing is required at least once every five years. The stack testing is not dependent on the Title V permit term, but rather each five-year period. Stack testing is required for two of the three turbines during each period.

No stack testing for sulfur dioxide is required. The fuel sulfur certifications and analyses, in addition to the fuel consumption data, provide adequate means of demonstrating continuous compliance with the emission limitations.

Visible emissions evaluations and the associated schedule are addressed in the Monitoring section above.

<u>Reporting</u>

The Title V permit includes semi-annual compliance reporting, excess emission reporting, and requires reporting of the occurrence of any malfunctions or permit deviations. In addition to these reporting requirements, the following reporting requirements are from the PSD permit issued on March 5, 1991 and amended on November 28, 2005, June 13, 2007, and April 10, 2008. The condition numbers below are from the PSD permit; a copy of the permit is enclosed in Attachment B.

Condition 19: The condition establishes guidelines and requirements for semi-annual reports for NOx excess emissions and SO_2 excess emissions. The condition is more stringent than the applicable NSPS Subpart GG requirements; the NSPS citations have been included in the condition.

GASOLINE DISPENSING OPERATIONS

<u>Limitations</u>

The gasoline fueling station and aboveground storage tank (ES-4) is subject to the requirements of *40 CFR 63 Subpart CCCCCC - National Emission Standards for Hazardous Air Pollutants for Source Category: Gasoline Dispensing Facilities*. The following limitations are established in accordance with the MACT Standards; condition numbers below refer to the Article 3 permit:

Condition 19: The facility must, at all times, operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions.

Condition 20: The requirements for gasoline dispensing facilities with a throughput of less than 10,000 gallons per month are included in this permit Condition.

<u>Monitoring, Recordkeeping, and Reporting</u>

The following monitoring, recordkeeping, and reporting requirements are taken from *40 CFR 63 Subpart CCCCCC*. The following requirements are established in accordance with the MACT Standards; condition numbers below refer to the Article 3 permit:

Condition 21: Monitoring - The permittee shall monitor the monthly throughput of gasoline to the GDF. Monthly throughput is the total volume of gasoline loaded into, or dispensed from, all the gasoline storage tanks located at a single affected GDF. If an area source has two or more GDF at separate locations within the area source, each GDF is treated as a separate affected source.

Condition 22: Recordkeeping - The condition establishes the other recordkeeping requirements – requirements include: malfunction records, actions during malfunction, and documentation of gasoline throughput.

The monitoring, recordkeeping, and reporting requirements established in the MACT provide a means of demonstrating continuous compliance with the limitations.

TITLE IV (PHASE II ACID RAIN) PERMIT ALLOWANCES AND REQUIREMENTS

The federal Acid Rain Program regulates fossil-fuel-fired electric generating facilities having more than 25 MW capacity that sell electricity. DEQ issues Phase II Acid Rain permits pursuant to 9VAC5 Chapter 80, Article 3 of the Virginia Regulations for the Control and Abatement of Air Pollution (Article 3 Federal Operating Permit), in accordance with the following:

- Air Pollution Control Law of Virginia §10.1-1308 and §10.1-1322;
- Environmental Protection Agency (EPA) Final Full Approval of the Operating Permits Program (Titles IV and V) published in the Federal Register December 4, 2001, Volume 66, Number 233, Rules and Regulations, pages 62961-62967 and effective November 30, 2001; and
- 40 CFR §§72.1 through 76.16

The combustion turbines (CT-1, CT-2, and CT-3) are subject to Phase II Acid Rain permitting. Its current Acid Rain permit expired on December 31, 2011. The Acid Rain permit renewal application was received on June 28, 2016, and the facility has been operating under an application shield since the Acid Rain permit expired. The Phase II Acid Rain Program requirements, derived from the EPA Acid Rain Permit Application document, are incorporated into the Article 3 permit as Phase II Acid Rain Program conditions (Conditions 58 through 67).

CROSS-STATE AIR POLLUTION RULE (CSAPR)

The Cross-State Air Pollution Rule (CSAPR) (40 CFR 97 Subparts AAAAA through GGGGG) applies to power plants, specifically to stationary fossil-fuel-fired boilers or combustion turbines serving at any time, on or after January 1, 2005, a generator with a nameplate capacity >25 MWe producing electricity for sale. The CSAPR programs that apply in Virginia are the NOx Annual Trading Program (Subpart AAAAA), the SO_2 Group 1 Trading Program (Subpart CCCCC) and the NOx Ozone Season Group 3 Trading Program (Subpart GGGGG). Applicability criteria are the same for all three programs, so a unit meeting the criteria is subject to NOx Annual, SO_2 Group 1, and NOx Ozone Season Group 3 trading programs. Applicable CSAPR requirements (40 CFR 97 Subparts AAAAA, CCCCC, and GGGGG) are incorporated in the permit (Conditions 68 through 75) and include monitoring, recordkeeping and reporting sufficient to ensure compliance with CSAPR emissions limits/allowance requirements.

STREAMLINED REQUIREMENTS

The following requirements from 40 CFR 60 Subpart GG (Standards of Performance for Stationary Gas Turbines) for the three stationary gas turbines (CT-1, CT-2, and CT-3) have been streamlined in the Article 3 permit as follows:

Citation	Requirement	Streamlined Reason
40 CFR 60.332(a)(1) 40 CFR 60.332(a)(4) 40 CFR 60.332(b)	Standard for Nitrogen Oxides	NOx Emissions Standard requirements are addressed in Condition 12 of the PSD permit
40 CFR 60.333(b)	Standard for Sulfur Dioxide	SO_2 Emissions Standard requirements are addressed in Condition 10 and Condition 11 of the PSD permit
40 CFR 60.334(a)	Monitoring of Operations	NOx Monitoring requirements are addressed in Condition 5 of the PSD permit
40 CFR 60.334(g)	Parameter Monitoring Plan	Parameter Monitoring requirements are addressed in Condition 18 of the PSD permit
40 CFR 60.334(h)(3)(i)	Monitoring of Operations	SO_2 Monitoring requirements are addressed in Condition 11 of the PSD permit

Citation	Requirement	Streamlined Reason
40 CFR 60.334(j)	Reporting of Excess Emissions and Monitoring of Downtime	Reporting requirements are addressed in Condition 19 of the PSD Permit
40 CFR 60.335(b)(10)	Test Methods and Procedures	Testing procedures are addressed in Condition 11 of the PSD permit

INSIGNIFICANT EMISSIONS UNITS

The insignificant emission units are presumed to be in compliance with all requirements of the Clean Air Act as may apply. Based on this presumption, no monitoring, recordkeeping or reporting shall be required for these emission units in accordance with 9VAC5-80-490.

Insignificant emission units include the following:

Emission Unit No.	Emission Unit Description	Citation	Pollutants Emitted (9VAC5-80-720B)	Rated Capacity (9VAC5-80-720C)
IL-2	Fuel oil valves, pumps, flanges	9VAC5-80-720 B	VOC	-
IL-5	Turbine lube oil venting	9VAC5-80-720 B	VOC	-

[1] The citation criteria for insignificant activities are as follows:
9VAC5-80-720 B - Insignificant due to emission levels

COMPLIANCE PLAN

A compliance plan was not included in the application or in the permit.

PERMIT SHIELD AND INAPPLICABLE REQUIREMENTS

The provisions of 40 CFR Part 98 – Mandatory Greenhouse Gas Reporting require owners and operators of general stationary fuel combustion sources that emit 25,000 metric tons CO_{2e} or more per year in combined emissions from such units, to report greenhouse gas (GHG) emissions, annually. The definition of “applicable requirement” in 40 CFR 70.2 and 71.2 does not include requirements such as those included in Part 98, promulgated under Clean Air Act (CAA) section 114(a)(1) and 208. Therefore, the requirements of 40 CFR Part 98 are not applicable under the Title IV permitting program.

The following requirements have also been identified as inapplicable:

40 CFR 63, Subpart T, National Emission Standards for Halogenated Solvent Cleaning has been identified as being not applicable to the facility. The facility does not currently own or operate any equipment meeting the applicability criteria of this subpart.

40 CFR 63, Subpart VV, National Emission Standards for Oil-Water Separators and Organic-Water Separators has been identified as being not applicable to the facility. The following subpart is applicable to only facilities subject to other subparts that reference this subpart. Dominion is not subject to any subparts that reference this subpart.

40 CFR 63, Subpart YYYY, National Emission Standards for Halogenated Solvent Cleaning has been identified as being not applicable to the facility. These turbines are considered existing stationary combustion turbines and are specifically exempted in Section 63.6090(b)(4).

40 CFR 63, Subpart KKKK, Standards of Performance for Stationary Combustion Turbines has been identified as being not applicable to the facility. The following subpart is only applicable to stationary combustion turbines that commenced construction, modification or reconstruction after February 18, 2005.

40 CFR 64, Compliance Assurance Monitoring has been identified as being not applicable to the facility. Units subject to the Acid Rain Program or units subject to emission limitations or standards that apply under an emissions trading program are exempt from the requirements of 40 CFR Part 64, Compliance Assurance Monitoring (CAM). Dominion Energy – Elizabeth River CT Station is subject to both the Acid Rain Program and CSAPR.

9VAC5-70-10, 9VAC5-70-70, AIR POLLUTION EPISODE PREVENTION has been identified as being not applicable to the facility. The Hampton Roads area has been designated an attainment area; therefore, despite its listing in Appendix K, the requirements do not apply.

GENERAL CONDITIONS

The permit contains general conditions required by 40 CFR Part 70 and 9VAC5-80-490 that apply to all Federal-operating permitted sources. These include requirements for submitting semi-annual monitoring reports and an annual compliance certification report. The permit also requires notification of deviations from permit requirements or any excess emissions.

Comments on General Conditions

There are no comments on the general conditions.

Federal Enforceability

Article 3 (9VAC5-80-490 N) states that all terms and conditions in the Title V permit are enforceable by the administrator and citizens under the federal Clean Air Act, except those that have been designated as only state-enforceable.

Permit Expiration

This condition refers to the Board taking action on a permit application. The “Board” refers to the State Air Pollution Control Board. The authority to take action on permit application(s) has been delegated to the Regions as allowed by §2.2-604 and §10.1-1185 of the Code of Virginia, and the “Department of Environmental Quality Agency Policy Statement No. 2-09”.

Failure / Malfunction Reporting

Section 9VAC5-20-180 requires malfunction and excess emission reporting within four hours of discovery. Section 9VAC5-20-180 is from the general regulations. All affected facilities are subject to section 9VAC5-20-180 including Title V facilities. A facility may make a single report that meets the requirements of 9VAC5-20-180. The report must be made within four daytime business hours of discovery of the malfunction.

Permit Modification

This general condition cites the sections that follow:

9VAC5-80-50. Applicability, Federal Operating Permits for Acid Rain Sources
9VAC5-80-550. Changes to Permits
9VAC5-80-660. Enforcement
9VAC5-80-1100. Applicability, Permits For New and Modified Stationary Sources
9VAC5-80-1605. Applicability, Permits For Major Stationary Sources and Modifications Located in Prevention of Significant Deterioration Areas
9VAC5-80-2000. Applicability, Permits for Major Stationary Sources and Major Modifications Locating in Nonattainment Areas

Asbestos Requirements

The Virginia Department of Labor and Industry under Section 40.1-51.20 of the Code of Virginia also holds authority to enforce 40 CFR 61 Subpart M, National Emission Standards for Asbestos.

FUTURE APPLICABLE REQUIREMENTS

No future applicable requirements were identified by the applicant.

CONFIDENTIAL INFORMATION

No confidential information request has been made. All portions of the permit and application are available for public review.

PUBLIC PARTICIPATION

A public notice regarding the draft permit was placed in the **Virginian-Pilot** newspaper, in Chesapeake, Virginia, on **December 14, 2022**. All persons on the Title V mailing list were sent a copy of the public notice by either electronic mail or in letters on **December 13, 2022**. North Carolina, the only affected state, was sent a copy of the public notice on **December 8, 2022**. The proposed 30-day public comment period ran from **December 14, 2022, to January 13, 2023**. No public comments were received.

EPA was notified of the public notice and sent a copy of the Statement of Basis and the draft permit on **December 8, 2022**. No comments were received; EPA notified the Air Permit Writer by email on **January 18, 2023** (*EPA has reviewed the SOB and draft permit and has no comments*). EPA comment period ended on **January 30, 2023**.

ATTACHMENTS

Attachment A – 2021 Annual Emissions Update
Attachment B – Prevention of Significant Deterioration (PSD) Permit dated March 5, 1991 and amended on November 28, 2005, June 13, 2007, and April 10, 2008

Dominion Energy Services, Inc.
120 Tredegar Street
Richmond, VA 23219
DominionEnergy.com

Dominion Energy®

BY ELECTRONIC MAIL
john.brandt@deq.virginia.gov

Apr 8, 2022

Mr. John Brandt
Air Compliance Manager
Virginia Department of Environmental Quality
Tidewater Regional Office
5636 Southern Blvd.
Virginia Beach, VA 23462

Re: **2021 Air Emissions Statement and Annual Update**
Dominion Energy -- Elizabeth River CT Station
DEQ Air Registration No. 61108

Dear Mr. Brandt:

Dominion Energy is submitting the Air Emissions Statement and Annual Update reports for Elizabeth River CT Station, as required by 9 VAC 5-20-160.

If you have any questions or require any additional information, please contact Daniel Kolmer at (804) 510-9366 or Daniel.R.Kolmer@dominionenergy.com.

Sincerely,

for

Molly A. Parker
Director, Environmental Services

Enclosure

VIRGINIA DEPARTMENT OF
ENVIRONMENTAL QUALITY

2021 EMISSION STATEMENT

Please correct any errors in the information below (cross out & replace)

FACILITY NAME ***DOMINION ENERGY - ELIZABETH RIVER CT STATION***			***REGISTRATION #*** *61108*
LOCATION ADDRESS ***2837 S Military Hwy, Chesapeake, VA 23323***			***COUNTY/CITY*** ***Chesapeake City 550***
MAILING ADDRESS ***120 Tredegar Street, Richmond VA 23219***			
CONTACT PERSON *TODD ALONZO*	***TELEPHONE NUMBER*** *(804) 432-6622*	***PRIMARY NAICS*** *Fossil Fuel Electric Power Generation 221112*	*For Agency Use Only*

FACILITY TOTALS *(Sum emissions from attached pages)*

POLLUTANTS	ANNUAL		OZONE SEASON	
TOTAL VOC EMISSIONS	0.21	TONS/YR	1.8	LBS/DAY
TOTAL NO_X EMISSIONS	49.20	TONS/YR	352.2	LBS/DAY
TOTAL SO_2 EMISSIONS	4.90	TONS/YR	NA	
TOTAL PM_{10} EMISSIONS	2.26	TONS/YR	NA	
TOTAL PB EMISSIONS	1.3E-03	TONS/YR	NA	
TOTAL TRS EMISSIONS	NA	TONS/YR	NA	
TOTAL TNMOC EMISSIONS (landfills only)	NA	TONS/YR	NA	
TOTAL non-VOC/non-PM HAP EMISSIONS	0.00	TONS/YR	NA	
TOTAL CO EMISSIONS	4.93	TONS/YR	NA	
TOTAL $PM_{2.5}$ EMISSIONS	2.26	TONS/YR	NA	
TOTAL NH3 EMISSIONS	0.00	TONS/YR	NA	

PLEASE ATTACH "ANNUAL UPDATE REPORT" AND "DOCUMENT CERTIFICATION" with appropriate signature.

DOCUMENT CERTIFICATION

Facility Name: Dominion Energy – Elizabeth River CT Station

Registration #: 61108

Facility Location: 2837 S Military Hwy, Chesapeake, VA 23323

Type of Submittal Attached: Emission Statement

Certification: I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering and evaluating the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

Name of Responsible Official (Print): Mohammed Alfayyoumi

Title: Director, Power Generation

Signature: Mohammed Alfayyoumi Date: 04/08/2022

2021 EMISSION CALCULATIONS
OPTION I: EMISSION FACTOR METHOD

REGISTRATION #: 61108 *REL. POINT NO.:* 1 *UNIT NO.:* 1 *PROCESS NO.:* 1, 3, 4 *SCC NO.:* 20100101

#1 Turbine - #2 Oil		ANNUAL		PEAK OZONE SEASON (JUNE, JULY, AUGUST)	
THRUPUT (with units)		68,145	mmBtu	15,230	mmBtu
NO. OPERATING DAYS			days	92	days
NO. OPERATING HOURS PER DAY			hours	24	hours
DAILY THRUPUT (with units) = Thruput/days		N/A		166	mmBtu per day
VOC EMISSION FACTOR (with units) = E. F.		1.5E-03	lb/mmBtu		
Emission Factor Source[1]	Control Efficiency Basis[2]	ST			
VOC CONTROL DEVICE CODE[3]					
Avg. VOC CONTROL EFFICIENCY[4] = C.E.			%		%
VOC EMISSIONS[5]		5.1E-02	tons VOC per yr	0.2	lbs VOC per day
NOx EMISSION FACTOR (with units) = E. F.		LME			
Emission Factor Source[1]	Control Efficiency Basis[2]	Part 75 LME data			
NOx CONTROL DEVICE CODE[3]					
Avg. NOx CONTROL EFFICIENCY[4] = C.E.			%		%
NOx EMISSIONS[5]		14.4	tons NOx per yr	113.0	lbs NOx per day
SO2 EMISSION FACTOR (with units) = E. F.		LME			
Emission Factor Source[1]	Control Efficiency Basis[2]	Part 75 LME data			
FUEL PARAMETER (% ash or % sulfur) = FP			%		
SO2 CONTROL DEVICE CODE[3]					
Avg. SO2 CONTROL EFFICIENCY[4] = C.E.			%		
SO2 EMISSIONS[5]		1.8	tons SO2 per yr		
PM10 EMISSION FACTOR (with units) = E. F.		1.2E-02	lb/mmBtu		
Emission Factor Source[1]	Control Efficiency Basis[2]	AP-42 Table 3.1-2a			
FUEL PARAMETER (% ash or % sulfur) = FP			%		
PM10 CONTROL DEVICE CODE[3]					
Avg. PM10 CONTROL EFFICIENCY[4] = C.E.			%		
PM10 EMISSIONS[5]		0.39	tons PM10 per yr		
Pb EMISSION FACTOR (with units) = E. F.		1.4E-05	lb/mmBtu		
Emission Factor Source[1]	Control Efficiency Basis[2]	AP-42 Table 3.1-2a			
Pb CONTROL DEVICE CODE[3]					
Avg. Pb CONTROL EFFICIENCY[4] = C.E.			%		
Pb EMISSIONS[5]		5.0E-04	tons Pb per yr		

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2. **A** = Tested (by EPA Reference Method); **B** = Tested (other); **C =** Material balance**;** **D** = Design; O **=** Other (describe on separate sheet)
3. See 3-digit control device codes listed in appendix.
4. Note control efficiency will be zero if there is no control device **OR** the emission factor accounts for controls (i.e. EF is identified to be "with controls").
5. Annual Emissions = ANNUAL THRUPUT x EF x FP x (1/2000) x (100 - CE)/100; Ozone Emissions = DAILY THRUPUT x EF x FP x (100-CE)/100

2021 EMISSION CALCULATIONS
OPTION I: EMISSION FACTOR METHOD

REGISTRATION #: 61108 *REL. POINT NO.:* 1 *UNIT NO.:* 1 *PROCESS NO.:* 1, 3, 4 *SCC NO.:* 20100101

#1 Turbine - #2 Oil		ANNUAL		PEAK OZONE SEASON (JUNE, JULY, AUGUST)	
THRUPUT (with units)		68,145	mmBtu		
NO. OPERATING DAYS			days		
NO. OPERATING HOURS PER DAY			hours		
DAILY THRUPUT (with units) = Thruput/days		N/A			
TRS EMISSION FACTOR (with units) = E. F.					
Emission Factor Source[1]	Control Efficiency Basis[2]				
TRS CONTROL DEVICE CODE[3]					
Avg. TRS CONTROL EFFICIENCY[4] = C.E.			%		
5			tons TRS per yr		
PM EMISSION FACTOR (with units) = E. F.		1.2E-02	lb/mmBtu		
Emission Factor Source[1]	Control Efficiency Basis[2]	AP-42 Table 3.1-2a			
FUEL PARAMETER (% ash or % sulfur) = FP					
Total PM CONTROL DEVICE CODE[3]					
Avg. Total PM CONTROL EFFICIENCY[4] = C.E.			%		
Total PM EMISSIONS[5]		0.39	tons PM-Total per yr		
CO EMISSION FACTOR (with units) = E. F.		6E-03	lb/mmBtu		
Emission Factor Source[1]	Control Efficiency Basis[2]	ST			
CO CONTROL DEVICE CODE[3]					
Avg. CO CONTROL EFFICIENCY[4] = C.E.			%		
CO EMISSIONS[5]		2.0E-01	tons CO per yr		
$PM_{2.5}$ EMISSION FACTOR (with units) = E. F.		1.2E-02	lb/mmBtu		
Emission Factor Source[1]	Control Efficiency Basis[2]	AP-42 Table 3.1-2a			
FUEL PARAMETER (% ash or % sulfur) = FP			%		
$PM_{2.5}$ CONTROL DEVICE CODE[2]					
Avg. $PM_{2.5}$ CONTROL EFFICIENCY[3] = C.E.			%		
$PM_{2.5}$ EMISSIONS[5]		0.39	tons $PM_{2.5}$ per yr		
NH_3 EMISSION FACTOR (with units) = E. F.		no factor			
Emission Factor Source[1]	Control Efficiency Basis[2]				
NH_3 CONTROL DEVICE CODE[3]					
Avg. NH_3 CONTROL EFFICIENCY[4] = C.E.			%		
NH_3 EMISSIONS[5]		0.00	tons NH_3 per yr		

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2. **A** = Tested (by EPA Reference Method); **B** = Tested (other); **C =** Material balance**;** **D** = Design; O **=** Other (describe on separate sheet)
3. See 3-digit control device codes listed in appendix.
4. Note control efficiency will be zero if there is no control device **OR** the emission factor accounts for controls (i.e. EF is identified to be "with controls").
5. Annual Emissions = ANNUAL THRUPUT x EF x FP x (1/2000) x (100 - CE)/100; Ozone Emissions = DAILY THRUPUT x EF x FP x (100-CE)/100

2021 EMISSION CALCULATIONS
OPTION I: EMISSION FACTOR METHOD

REGISTRATION #: 61108 *REL. POINT NO.:* 1 *UNIT NO.:* 1 *PROCESS NO.:* 1, 3, 4 *SCC NO.:* 20100101

#1 Turbine - #2 Oil		ANNUAL		PEAK OZONE SEASON (JUNE, JULY, AUGUST)	
THRUPUT (with units)		68,145	mmBtu		
NO. OPERATING DAYS			days		
NO. OPERATING HOURS PER DAY			hours		
DAILY THRUPUT (with units) = Thruput/days		N/A			
HAP EMISSION FACTOR (with units) = E. F.		9.94E-03	lb/mmBtu		
Emission Factor Source[1]	Control Efficiency Basis[2]	O - Southern Co. method			
HAP CONTROL DEVICE CODE[3]					
Avg. HAP CONTROL EFFICIENCY[4] = C.E.			%		
HAP (H2S04 mist) EMISSIONS[5]		0.34	tons per yr		
HAP EMISSION FACTOR (with units) = E. F.		<3.1E-07	lb/mmBtu		
Emission Factor Source[1]	Control Efficiency Basis[2]	AP-42, Table 3.1-5, 5th Ed 4/00			
HAP CONTROL DEVICE CODE[3]					
Avg. HAP CONTROL EFFICIENCY[4] = C.E.			%		
HAP (Beryllium) EMISSIONS[5]		1.1E-05	tons per yr		
HAP EMISSION FACTOR (with units) = E. F.					
Emission Factor Source[1]	Control Efficiency Basis[2]				
HAP CONTROL DEVICE CODE[3]					
Avg. HAP CONTROL EFFICIENCY[4] = C.E.			%		
HAP (________) EMISSIONS[5]			tons per yr		
HAP EMISSION FACTOR (with units) = E. F.					
Emission Factor Source[1]	Control Efficiency Basis[2]				
HAP CONTROL DEVICE CODE[3]					
Avg. HAP CONTROL EFFICIENCY[4] = C.E.			%		
HAP (________) EMISSIONS[5]			tons per yr		
HAP EMISSION FACTOR (with units) = E. F.					
Emission Factor Source[1]	Control Efficiency Basis[2]				
HAP CONTROL DEVICE CODE[3]					
Avg. HAP CONTROL EFFICIENCY[4] = C.E.			%		
HAP (________) EMISSIONS[5]			tons per yr		
HAP EMISSION FACTOR (with units) = E. F.					
Emission Factor Source[1]	Control Efficiency Basis[2]				
HAP CONTROL DEVICE CODE[3]					
Avg. HAP CONTROL EFFICIENCY[4] = C.E.			%		
HAP (________) EMISSIONS[5]			tons per yr		

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2. **A** = Tested (by EPA Reference Method); **B** = Tested (other); **C =** Material balance**;** **D** = Design; O = Other (describe on separate sheet)
3. See 3-digit control device codes listed in appendix.
4. Note control efficiency will be zero if there is no control device **OR** the emission factor accounts for controls (i.e. EF is identified to be "with controls").
5. Annual Emissions = ANNUAL THRUPUT x EF x FP x (1/2000) x (100 - CE)/100; Ozone Emissions = DAILY THRUPUT x EF x FP x (100-CE)/100

2021 EMISSION CALCULATIONS
OPTION I: EMISSION FACTOR METHOD

REGISTRATION #: 61108 *REL. POINT NO.:* 1 *UNIT NO.:* 1 *PROCESS NO.:* 2 *SCC NO.:* 20100201

#1 Turbine - Nat. Gas		ANNUAL		PEAK OZONE SEASON (JUNE, JULY, AUGUST)	
THRUPUT (with units)		78,161	mmBtu	28,850	mmBtu
NO. OPERATING DAYS			days	92	days
NO. OPERATING HOURS PER DAY			hours	24	hours
DAILY THRUPUT (with units) = Thruput/days		N/A		314	mmBtu per day
VOC EMISSION FACTOR (with units) = E. F.		4.0E-04	lb/mmBtu		
Emission Factor Source[1]	Control Efficiency Basis[2]	ST			
VOC CONTROL DEVICE CODE[3]					
Avg. VOC CONTROL EFFICIENCY[4] = C.E.			%		%
VOC EMISSIONS[5]		0.02	tons VOC per yr	0.1	lbs VOC per day
NOx EMISSION FACTOR (with units) = E. F.		LME			
Emission Factor Source[1]	Control Efficiency Basis[2]	Part 75 LME data			
NOx CONTROL DEVICE CODE[3]					
Avg. NOx CONTROL EFFICIENCY[4] = C.E.			%		%
NOx EMISSIONS[5]		included with No.2 Oil		Inc. w/ No. 2 Oil	lbs NOx per day
SO2 EMISSION FACTOR (with units) = E. F.		LME			
Emission Factor Source[1]	Control Efficiency Basis[2]	Part 75 LME data			
FUEL PARAMETER (% ash or % sulfur) = FP			%		
SO2 CONTROL DEVICE CODE[3]					
Avg. SO2 CONTROL EFFICIENCY[4] = C.E.			%		
SO2 EMISSIONS[5]		included with No.2 Oil			
PM10 EMISSION FACTOR (with units) = E. F.		6.6E-03	lb/mmBtu		
Emission Factor Source[1]	Control Efficiency Basis[2]	AP-42 Table 3.1-2a			
FUEL PARAMETER (% ash or % sulfur) = FP			%		
PM10 CONTROL DEVICE CODE[3]					
Avg. PM10 CONTROL EFFICIENCY[4] = C.E.			%		
PM10 EMISSIONS[5]		0.26	tons PM10 per yr		
Pb EMISSION FACTOR (with units) = E. F.		no factor			
Emission Factor Source[1]	Control Efficiency Basis[2]				
Pb CONTROL DEVICE CODE[3]					
Avg. Pb CONTROL EFFICIENCY[4] = C.E.			%		
Pb EMISSIONS[5]		0.00	tons Pb per yr		

1. **AP42; CEMS; ST** = Stack test; **F** = Federal factor (EPA standard factor); **O** = Other (describe on separate sheet)
2. **A** = Tested (by EPA Reference Method); **B** = Tested (other); **C =** Material balance**;** **D** = Design; O **=** Other (describe on separate sheet)
3. See 3-digit control device codes listed in appendix.
4. Note control efficiency will be zero if there is no control device **OR** the emission factor accounts for controls (i.e. EF is identified to be "with controls").
5. Annual Emissions = ANNUAL THRUPUT x EF x FP x (1/2000) x (100 - CE)/100; Ozone Emissions = DAILY THRUPUT x EF x FP x (100-CE)/100

2021 EMISSION CALCULATIONS
OPTION I: EMISSION FACTOR METHOD

REGISTRATION #: 61108 *REL. POINT NO.:* 1 *UNIT NO.:* 1 *PROCESS NO.:* 2 *SCC NO.:* 20100201

#1 Turbine - Nat. Gas		ANNUAL		PEAK OZONE SEASON (JUNE, JULY, AUGUST)	
THRUPUT (with units)		78,161	mmBtu		
NO. OPERATING DAYS			days		
NO. OPERATING HOURS PER DAY			hours		
DAILY THRUPUT (with units) = Thruput/days		N/A			
TRS EMISSION FACTOR (with units) = E. F.					
Emission Factor Source[1]	Control Efficiency Basis[2]				
TRS CONTROL DEVICE CODE[3]					
Avg. TRS CONTROL EFFICIENCY[4] = C.E.			%		
[5]			tons TRS per yr		
PM-Total EMISSION FACTOR (with units) = E. F.		6.6E-03	lb/mmBtu		
Emission Factor Source[1]	Control Efficiency Basis[2]	AP-42 (Table 3.1-2a)			
FUEL PARAMETER (% ash or % sulfur) = FP					
PM-Total CONTROL DEVICE CODE[3]					
Avg. PM-Total CONTROL EFFICIENCY[4] = C.E.			%		
PM-Total EMISSIONS[5]		0.26	tons PM-Total per yr		
CO EMISSION FACTOR (with units) = E. F.		2.4E-02	lb/mmBtu		
Emission Factor Source[1]	Control Efficiency Basis[2]	ST			
CO CONTROL DEVICE CODE[3]					
Avg. CO CONTROL EFFICIENCY[4] = C.E.			%		
CO EMISSIONS[5]		0.94	tons CO per yr		
$PM_{2.5}$ EMISSION FACTOR (with units) = E. F.		6.6E-03	lb/mmBtu		
Emission Factor Source[1]	Control Efficiency Basis[2]	AP-42 Table 3.1-2a			
FUEL PARAMETER (% ash or % sulfur) = FP			%		
$PM_{2.5}$ CONTROL DEVICE CODE[2]					
Avg. $PM_{2.5}$ CONTROL EFFICIENCY[3] = C.E.			%		
$PM_{2.5}$ EMISSIONS[5]		0.26	tons $PM_{2.5}$ per yr		
NH_3 EMISSION FACTOR (with units) = E. F.		no factor			
Emission Factor Source[1]	Control Efficiency Basis[2]				
NH_3 CONTROL DEVICE CODE[3]					
Avg. NH_3 CONTROL EFFICIENCY[4] = C.E.			%		
NH_3 EMISSIONS[5]		0.00	tons NH_3 per yr		

1. **AP42; CEMS; ST** = Stack test; **F** = Federal factor (EPA standard factor); **O** = Other (describe on separate sheet)
2. **A** = Tested (by EPA Reference Method); **B** = Tested (other); **C =** Material balance**;** **D** = Design; O **=** Other (describe on separate sheet)
3. See 3-digit control device codes listed in appendix.
4. Note control efficiency will be zero if there is no control device **OR** the emission factor accounts for controls (i.e. EF is identified to be "with controls").
5. Annual Emissions = ANNUAL THRUPUT x EF x FP x (1/2000) x (100 - CE)/100; Ozone Emissions = DAILY THRUPUT x EF x FP x (100-CE)/100

2021 EMISSION CALCULATIONS
OPTION I: EMISSION FACTOR METHOD

REGISTRATION #: 61108 *REL. POINT NO.:* 1 *UNIT NO.:* 1 *PROCESS NO.:* 2 *SCC NO.:* 20100201

#1 Turbine - Nat. Gas		ANNUAL		PEAK OZONE SEASON (JUNE, JULY, AUGUST)	
THRUPUT (with units)		78,161	mmBtu		
NO. OPERATING DAYS			days		
NO. OPERATING HOURS PER DAY			hours		
DAILY THRUPUT (with units) = Thruput/days		N/A			
HAP EMISSION FACTOR (with units) = E. F.		3.28E-04	lb/mmBtu		
Emission Factor Source[1]	Control Efficiency Basis[2]	O - Southern Co. method			
HAP CONTROL DEVICE CODE[3]					
Avg. HAP CONTROL EFFICIENCY[4] = C.E.			%		
HAP (H2S04 mist) EMISSIONS[5]		0.01	tons per yr		
HAP EMISSION FACTOR (with units) = E. F.		no factor			
Emission Factor Source[1]	Control Efficiency Basis[2]				
HAP CONTROL DEVICE CODE[3]					
Avg. HAP CONTROL EFFICIENCY[4] = C.E.			%		
HAP (Beryllium) EMISSIONS[5]		0.00	tons per yr		
HAP EMISSION FACTOR (with units) = E. F.					
Emission Factor Source[1]	Control Efficiency Basis[2]				
HAP CONTROL DEVICE CODE[3]					
Avg. HAP CONTROL EFFICIENCY[4] = C.E.			%		
HAP (______________________) EMISSIONS[5]			tons per yr		
HAP EMISSION FACTOR (with units) = E. F.					
Emission Factor Source[1]	Control Efficiency Basis[2]				
HAP CONTROL DEVICE CODE[3]					
Avg. HAP CONTROL EFFICIENCY[4] = C.E.			%		
HAP (______________________) EMISSIONS[5]			tons per yr		
HAP EMISSION FACTOR (with units) = E. F.					
Emission Factor Source[1]	Control Efficiency Basis[2]				
HAP CONTROL DEVICE CODE[3]					
Avg. HAP CONTROL EFFICIENCY[4] = C.E.			%		
HAP (______________________) EMISSIONS[5]			tons per yr		
HAP EMISSION FACTOR (with units) = E. F.					
Emission Factor Source[1]	Control Efficiency Basis[2]				
HAP CONTROL DEVICE CODE[3]					
Avg. HAP CONTROL EFFICIENCY[4] = C.E.			%		
HAP (______________________) EMISSIONS[5]			tons per yr		

1. **AP42; CEMS; ST** = Stack test; **F** = Federal factor (EPA standard factor); **O** = Other (describe on separate sheet)
2. **A** = Tested (by EPA Reference Method); **B** = Tested (other); **C** = Material balance**;** **D** = Design; O = Other (describe on separate sheet)
3. See 3-digit control device codes listed in appendix.
4. Note control efficiency will be zero if there is no control device **OR** the emission factor accounts for controls (i.e. EF is identified to be "with controls").
5. Annual Emissions = ANNUAL THRUPUT x EF x FP x (1/2000) x (100 - CE)/100; Ozone Emissions = DAILY THRUPUT x EF x FP x (100-CE)/100

2021 EMISSION CALCULATIONS
OPTION I: EMISSION FACTOR METHOD

REGISTRATION #: 61108 *REL. POINT NO.:* 2 *UNIT NO.:* 2 *PROCESS NO.:* 1, 3, 4 *SCC NO.:* 20100101

#2 Turbine - #2 Oil		ANNUAL		PEAK OZONE SEASON (JUNE, JULY, AUGUST)	
THRUPUT (with units)		44,962	mmBtu	44,962	mmBtu
NO. OPERATING DAYS			days	92	days
NO. OPERATING HOURS PER DAY			hours	24	hours
DAILY THRUPUT (with units) = Thruput/days		N/A		489	mmBtu per day
VOC EMISSION FACTOR (with units) = E. F.		1.5E-03	lb/mmBtu		
Emission Factor Source[1]	Control Efficiency Basis[2]	ST			
VOC CONTROL DEVICE CODE[3]					
Avg. VOC CONTROL EFFICIENCY[4] = C.E.			%		%
VOC EMISSIONS[5]		3.4E-02	tons VOC per yr	0.7	lbs VOC per day
NOx EMISSION FACTOR (with units) = E. F.		LME			
Emission Factor Source[1]	Control Efficiency Basis[2]	Part 75 LME data			
NOx CONTROL DEVICE CODE[3]					
Avg. NOx CONTROL EFFICIENCY[4] = C.E.			%		%
NOx EMISSIONS[5]		23.3	tons NOx per yr	169.6	lbs NOx per day
SO2 EMISSION FACTOR (with units) = E. F.		LME			
Emission Factor Source[1]	Control Efficiency Basis[2]	Part 75 LME data			
FUEL PARAMETER (% ash or % sulfur) = FP			%		
SO2 CONTROL DEVICE CODE[3]					
Avg. SO2 CONTROL EFFICIENCY[4] = C.E.			%		
SO2 EMISSIONS[5]		1.2	tons SO2 per yr		
PM10 EMISSION FACTOR (with units) = E. F.		1.2E-02	lb/mmBtu		
Emission Factor Source[1]	Control Efficiency Basis[2]	AP-42 Table 3.1-2a			
FUEL PARAMETER (% ash or % sulfur) = FP			%		
PM10 CONTROL DEVICE CODE[3]					
Avg. PM10 CONTROL EFFICIENCY[4] = C.E.			%		
PM10 EMISSIONS[5]		0.26	tons PM10 per yr		
Pb EMISSION FACTOR (with units) = E. F.		1.4E-05	lb/mmBtu		
Emission Factor Source[1]	Control Efficiency Basis[2]	AP-42 Table 3.1-2a			
Pb CONTROL DEVICE CODE[3]					
Avg. Pb CONTROL EFFICIENCY[4] = C.E.			%		
Pb EMISSIONS[5]		3.0E-04	tons Pb per yr		

1. **AP42; CEMS; ST** = Stack test; **F** = Federal factor (EPA standard factor); **O** = Other (describe on separate sheet)
2. **A** = Tested (by EPA Reference Method); **B** = Tested (other); **C =** Material balance**;** **D** = Design; O **=** Other (describe on separate sheet)
3. See 3-digit control device codes listed in appendix.
4. Note control efficiency will be zero if there is no control device **OR** the emission factor accounts for controls (i.e. EF is identified to be "with controls").
5. Annual Emissions = ANNUAL THRUPUT x EF x FP x (1/2000) x (100 - CE)/100; Ozone Emissions = DAILY THRUPUT x EF x FP x (100-CE)/100

2021 EMISSION CALCULATIONS
OPTION I: EMISSION FACTOR METHOD

REGISTRATION #: 61108 *REL. POINT NO.:* 2 *UNIT NO.:* 2 *PROCESS NO.:* 1, 3, 4 *SCC NO.:* 20100101

#2 Turbine - #2 Oil		ANNUAL		PEAK OZONE SEASON (JUNE, JULY, AUGUST)	
THRUPUT (with units)		44,962	mmBtu		
NO. OPERATING DAYS			days		
NO. OPERATING HOURS PER DAY			hours		
DAILY THRUPUT (with units) = Thruput/days		N/A			
TRS EMISSION FACTOR (with units) = E. F.					
Emission Factor Source[1]	Control Efficiency Basis[2]				
TRS CONTROL DEVICE CODE[3]					
Avg. TRS CONTROL EFFICIENCY[4] = C.E.			%		
5			tons TRS per yr		
PM EMISSION FACTOR (with units) = E. F.		1.2E-02	lb/mmBtu		
Emission Factor Source[1]	Control Efficiency Basis[2]	AP-42 Table 3.1-2a			
FUEL PARAMETER (% ash or % sulfur) = FP					
Total PM CONTROL DEVICE CODE[3]					
Avg. Total PM CONTROL EFFICIENCY[4] = C.E.			%		
Total PM EMISSIONS[5]		0.26	tons PM-Total per yr		
CO EMISSION FACTOR (with units) = E. F.		6E-03	lb/mmBtu		
Emission Factor Source[1]	Control Efficiency Basis[2]	ST			
CO CONTROL DEVICE CODE[3]					
Avg. CO CONTROL EFFICIENCY[4] = C.E.			%		
CO EMISSIONS[5]		0.13	tons CO per yr		
$PM_{2.5}$ EMISSION FACTOR (with units) = E. F.		1.2E-02	lb/mmBtu		
Emission Factor Source[1]	Control Efficiency Basis[2]	AP-42 Table 3.1-2a			
FUEL PARAMETER (% ash or % sulfur) = FP			%		
$PM_{2.5}$ CONTROL DEVICE CODE[2]					
Avg. $PM_{2.5}$ CONTROL EFFICIENCY[3] = C.E.			%		
$PM_{2.5}$ EMISSIONS[5]		0.26	tons $PM_{2.5}$ per yr		
NH_3 EMISSION FACTOR (with units) = E. F.		no factor			
Emission Factor Source[1]	Control Efficiency Basis[2]				
NH_3 CONTROL DEVICE CODE[3]					
Avg. NH_3 CONTROL EFFICIENCY[4] = C.E.			%		
NH_3 EMISSIONS[5]		0.00	tons NH_3 per yr		

1. **AP42; CEMS; ST** = Stack test; **F** = Federal factor (EPA standard factor); **O** = Other (describe on separate sheet)
2. **A** = Tested (by EPA Reference Method); **B** = Tested (other); **C =** Material balance**;** **D** = Design; O **=** Other (describe on separate sheet)
3. See 3-digit control device codes listed in appendix.
4. Note control efficiency will be zero if there is no control device **OR** the emission factor accounts for controls (i.e. EF is identified to be "with controls").
5. Annual Emissions = ANNUAL THRUPUT x EF x FP x (1/2000) x (100 - CE)/100; Ozone Emissions = DAILY THRUPUT x EF x FP x (100-CE)/100

2021 EMISSION CALCULATIONS
OPTION I: EMISSION FACTOR METHOD

REGISTRATION #: 61108 *REL. POINT NO.:* 2 *UNIT NO.:* 2 *PROCESS NO.:* 1, 3, 4 *SCC NO.:* 20100101

#2 Turbine - #2 Oil		ANNUAL		PEAK OZONE SEASON (JUNE, JULY, AUGUST)	
THRUPUT (with units)		44,962	mmBtu		
NO. OPERATING DAYS			days		
NO. OPERATING HOURS PER DAY			hours		
DAILY THRUPUT (with units) = Thruput/days		N/A			
HAP EMISSION FACTOR (with units) = E. F.		9.94E-03	lb/mmBtu		
Emission Factor Source[1]	Control Efficiency Basis[2]	O - Southern Co. method			
HAP CONTROL DEVICE CODE[3]					
Avg. HAP CONTROL EFFICIENCY[4] = C.E.			%		
HAP (H2S04 mist) EMISSIONS[5]		0.22	tons per yr		
HAP EMISSION FACTOR (with units) = E. F.		<3.1E-07	lb/mmBtu		
Emission Factor Source[1]	Control Efficiency Basis[2]	AP-42, Table 3.1-5, 5th Ed 4/00			
HAP CONTROL DEVICE CODE[3]					
Avg. HAP CONTROL EFFICIENCY[4] = C.E.			%		
HAP (Beryllium) EMISSIONS[5]		7.0E-06	tons per yr		
HAP EMISSION FACTOR (with units) = E. F.					
Emission Factor Source[1]	Control Efficiency Basis[2]				
HAP CONTROL DEVICE CODE[3]					
Avg. HAP CONTROL EFFICIENCY[4] = C.E.			%		
HAP (______) EMISSIONS[5]			tons per yr		
HAP EMISSION FACTOR (with units) = E. F.					
Emission Factor Source[1]	Control Efficiency Basis[2]				
HAP CONTROL DEVICE CODE[3]					
Avg. HAP CONTROL EFFICIENCY[4] = C.E.			%		
HAP (______) EMISSIONS[5]			tons per yr		
HAP EMISSION FACTOR (with units) = E. F.					
Emission Factor Source[1]	Control Efficiency Basis[2]				
HAP CONTROL DEVICE CODE[3]					
Avg. HAP CONTROL EFFICIENCY[4] = C.E.			%		
HAP (______) EMISSIONS[5]			tons per yr		
HAP EMISSION FACTOR (with units) = E. F.					
Emission Factor Source[1]	Control Efficiency Basis[2]				
HAP CONTROL DEVICE CODE[3]					
Avg. HAP CONTROL EFFICIENCY[4] = C.E.			%		
HAP (______) EMISSIONS[5]			tons per yr		

1. **AP42; CEMS; ST** = Stack test; **F** = Federal factor (EPA standard factor); **O** = Other (describe on separate sheet)
2. **A** = Tested (by EPA Reference Method); **B** = Tested (other); **C** = Material balance**;** **D** = Design; O = Other (describe on separate sheet)
3. See 3-digit control device codes listed in appendix.
4. Note control efficiency will be zero if there is no control device **OR** the emission factor accounts for controls (i.e. EF is identified to be "with controls").
5. Annual Emissions = ANNUAL THRUPUT x EF x FP x (1/2000) x (100 - CE)/100; Ozone Emissions = DAILY THRUPUT x EF x FP x (100-CE)/100

2021 EMISSION CALCULATIONS
OPTION I: EMISSION FACTOR METHOD

REGISTRATION #: 61108 *REL. POINT NO.:* 2 *UNIT NO.:* 2 *PROCESS NO.:* 2 *SCC NO.:* 20100201

#2 Turbine - Nat. Gas		ANNUAL		PEAK OZONE SEASON (JUNE, JULY, AUGUST)	
THRUPUT (with units)		257,096	mmBtu	103,845	mmBtu
NO. OPERATING DAYS			days	92	days
NO. OPERATING HOURS PER DAY			hours	24	hours
DAILY THRUPUT (with units) = Thruput/days		N/A		1,129	mmBtu per day
VOC EMISSION FACTOR (with units) = E. F.		4.0E-04	lb/mmBtu		
Emission Factor Source[1]	Control Efficiency Basis[2]	ST			
VOC CONTROL DEVICE CODE[3]					
Avg. VOC CONTROL EFFICIENCY[4] = C.E.			%		%
VOC EMISSIONS[5]		0.05	tons VOC per yr	0.45	lbs VOC per day
NOx EMISSION FACTOR (with units) = E. F.		LME			
Emission Factor Source[1]	Control Efficiency Basis[2]	Part 75 LME data			
NOx CONTROL DEVICE CODE[3]					
Avg. NOx CONTROL EFFICIENCY[4] = C.E.			%		%
NOx EMISSIONS[5]		included with No.2 Oil		Inc. w/ No. 2 Oil	lbs NOx per day
SO2 EMISSION FACTOR (with units) = E. F.		LME			
Emission Factor Source[1]	Control Efficiency Basis[2]	Part 75 LME data			
FUEL PARAMETER (% ash or % sulfur) = FP			%		
SO2 CONTROL DEVICE CODE[3]					
Avg. SO2 CONTROL EFFICIENCY[4] = C.E.			%		
SO2 EMISSIONS[5]		included with No.2 Oil			
PM10 EMISSION FACTOR (with units) = E. F.		6.6E-03	lb/mmBtu		
Emission Factor Source[1]	Control Efficiency Basis[2]	AP-42 Table 3.1-2a			
FUEL PARAMETER (% ash or % sulfur) = FP			%		
PM10 CONTROL DEVICE CODE[3]					
Avg. PM10 CONTROL EFFICIENCY[4] = C.E.			%		
PM10 EMISSIONS[5]		0.85	tons PM10 per yr		
Pb EMISSION FACTOR (with units) = E. F.		no factor			
Emission Factor Source[1]	Control Efficiency Basis[2]				
Pb CONTROL DEVICE CODE[3]					
Avg. Pb CONTROL EFFICIENCY[4] = C.E.			%		
Pb EMISSIONS[5]		0.00	tons Pb per yr		

1. **AP42; CEMS; ST** = Stack test; **F** = Federal factor (EPA standard factor); **O** = Other (describe on separate sheet)
2. **A** = Tested (by EPA Reference Method); **B** = Tested (other); **C =** Material balance**;** **D** = Design; O **=** Other (describe on separate sheet)
3. See 3-digit control device codes listed in appendix.
4. Note control efficiency will be zero if there is no control device **OR** the emission factor accounts for controls (i.e. EF is identified to be "with controls").
5. Annual Emissions = ANNUAL THRUPUT x EF x FP x (1/2000) x (100 - CE)/100; Ozone Emissions = DAILY THRUPUT x EF x FP x (100-CE)/100

2021 EMISSION CALCULATIONS
OPTION I: EMISSION FACTOR METHOD

REGISTRATION #: 61108 *REL. POINT NO.:* 2 *UNIT NO.:* 2 *PROCESS NO.:* 2 *SCC NO.:* 20100201

#2 Turbine - Nat. Gas		ANNUAL		PEAK OZONE SEASON (JUNE, JULY, AUGUST)	
THRUPUT (with units)		257,096	mmBtu		
NO. OPERATING DAYS			days		
NO. OPERATING HOURS PER DAY			hours		
DAILY THRUPUT (with units) = Thruput/days		N/A			
TRS EMISSION FACTOR (with units) = E. F.					
Emission Factor Source[1]	Control Efficiency Basis[2]				
TRS CONTROL DEVICE CODE[3]					
Avg. TRS CONTROL EFFICIENCY[4] = C.E.			%		
5			tons TRS per yr		
PM-Total EMISSION FACTOR (with units) = E. F.		6.6E-03	lb/mmBtu		
Emission Factor Source[1]	Control Efficiency Basis[2]	AP-42 (Table 3.1-2a)			
FUEL PARAMETER (% ash or % sulfur) = FP					
PM-Total CONTROL DEVICE CODE[3]					
Avg. PM-Total CONTROL EFFICIENCY[4] = C.E.			%		
PM-Total EMISSIONS[5]		0.85	tons PM-Total per yr		
CO EMISSION FACTOR (with units) = E. F.		2.4E-02	lb/mmBtu		
Emission Factor Source[1]	Control Efficiency Basis[2]	ST			
CO CONTROL DEVICE CODE[3]					
Avg. CO CONTROL EFFICIENCY[4] = C.E.			%		
CO EMISSIONS[5]		3.09	tons CO per yr		
$PM_{2.5}$ EMISSION FACTOR (with units) = E. F.		6.6E-03	lb/mmBtu		
Emission Factor Source[1]	Control Efficiency Basis[2]	AP-42 Table 3.1-2a			
FUEL PARAMETER (% ash or % sulfur) = FP			%		
$PM_{2.5}$ CONTROL DEVICE CODE[2]					
Avg. $PM_{2.5}$ CONTROL EFFICIENCY[3] = C.E.			%		
$PM_{2.5}$ EMISSIONS[5]		0.85	tons $PM_{2.5}$ per yr		
NH_3 EMISSION FACTOR (with units) = E. F.		no factor			
Emission Factor Source[1]	Control Efficiency Basis[2]				
NH_3 CONTROL DEVICE CODE[3]					
Avg. NH_3 CONTROL EFFICIENCY[4] = C.E.			%		
NH_3 EMISSIONS[5]		0.00	tons NH_3 per yr		

1. **AP42; CEMS; ST** = Stack test; **F** = Federal factor (EPA standard factor); **O** = Other (describe on separate sheet)
2. **A** = Tested (by EPA Reference Method); **B** = Tested (other); **C =** Material balance**;** **D** = Design; O **=** Other (describe on separate sheet)
3. See 3-digit control device codes listed in appendix.
4. Note control efficiency will be zero if there is no control device **OR** the emission factor accounts for controls (i.e. EF is identified to be "with controls").
5. Annual Emissions = ANNUAL THRUPUT x EF x FP x (1/2000) x (100 - CE)/100; Ozone Emissions = DAILY THRUPUT x EF x FP x (100-CE)/100

2021 EMISSION CALCULATIONS
OPTION I: EMISSION FACTOR METHOD

REGISTRATION #: 61108 *REL. POINT NO.:* 2 *UNIT NO.:* 2 *PROCESS NO.:* 2 *SCC NO.:* 20100201

#2 Turbine - Nat. Gas		ANNUAL		PEAK OZONE SEASON (JUNE, JULY, AUGUST)	
THRUPUT (with units)		257,096	mmBtu		
NO. OPERATING DAYS			days		
NO. OPERATING HOURS PER DAY			hours		
DAILY THRUPUT (with units) = Thruput/days		N/A			
HAP EMISSION FACTOR (with units) = E. F.		3.28E-04	lb/mmBtu		
Emission Factor Source[1]	Control Efficiency Basis[2]	O - Southern Co. method			
HAP CONTROL DEVICE CODE[3]					
Avg. HAP CONTROL EFFICIENCY[4] = C.E.			%		
HAP (H2S04 mist) EMISSIONS[5]		0.04	tons per yr		
HAP EMISSION FACTOR (with units) = E. F.		no factor			
Emission Factor Source[1]	Control Efficiency Basis[2]				
HAP CONTROL DEVICE CODE[3]					
Avg. HAP CONTROL EFFICIENCY[4] = C.E.			%		
HAP (Beryllium) EMISSIONS[5]		0.00	tons per yr		
HAP EMISSION FACTOR (with units) = E. F.					
Emission Factor Source[1]	Control Efficiency Basis[2]				
HAP CONTROL DEVICE CODE[3]					
Avg. HAP CONTROL EFFICIENCY[4] = C.E.			%		
HAP (______________________) EMISSIONS[5]			tons per yr		
HAP EMISSION FACTOR (with units) = E. F.					
Emission Factor Source[1]	Control Efficiency Basis[2]				
HAP CONTROL DEVICE CODE[3]					
Avg. HAP CONTROL EFFICIENCY[4] = C.E.			%		
HAP (______________________) EMISSIONS[5]			tons per yr		
HAP EMISSION FACTOR (with units) = E. F.					
Emission Factor Source[1]	Control Efficiency Basis[2]				
HAP CONTROL DEVICE CODE[3]					
Avg. HAP CONTROL EFFICIENCY[4] = C.E.			%		
HAP (______________________) EMISSIONS[5]			tons per yr		
HAP EMISSION FACTOR (with units) = E. F.					
Emission Factor Source[1]	Control Efficiency Basis[2]				
HAP CONTROL DEVICE CODE[3]					
Avg. HAP CONTROL EFFICIENCY[4] = C.E.			%		
HAP (______________________) EMISSIONS[5]			tons per yr		

1. **AP42; CEMS; ST** = Stack test; **F** = Federal factor (EPA standard factor); **O** = Other (describe on separate sheet)
2. **A** = Tested (by EPA Reference Method); **B** = Tested (other); **C =** Material balance**;** **D** = Design; O = Other (describe on separate sheet)
3. See 3-digit control device codes listed in appendix.
4. Note control efficiency will be zero if there is no control device **OR** the emission factor accounts for controls (i.e. EF is identified to be "with controls").
5. Annual Emissions = ANNUAL THRUPUT x EF x FP x (1/2000) x (100 - CE)/100; Ozone Emissions = DAILY THRUPUT x EF x FP x (100-CE)/100

2021 EMISSION CALCULATIONS
OPTION I: EMISSION FACTOR METHOD

REGISTRATION #: 61108 *REL. POINT NO.:* 3 *UNIT NO.:* 3 *PROCESS NO.:* 1, 3, 4 *SCC NO.:* 20100101

#3 Turbine - #2 Oil		ANNUAL		PEAK OZONE SEASON (JUNE, JULY, AUGUST)	
THRUPUT (with units)		69,451	mmBtu	14,710	mmBtu
NO. OPERATING DAYS			days	92	days
NO. OPERATING HOURS PER DAY			hours	24	hours
DAILY THRUPUT (with units) = Thruput/days		N/A		160	mmBtu per day
VOC EMISSION FACTOR (with units) = E. F.		1.5E-03	lb/mmBtu		
Emission Factor Source[1]	Control Efficiency Basis[2]	ST			
VOC CONTROL DEVICE CODE[3]					
Avg. VOC CONTROL EFFICIENCY[4] = C.E.			%		%
VOC EMISSIONS[5]		0.05	tons VOC per yr	0.2	lbs VOC per day
NOx EMISSION FACTOR (with units) = E. F.		LME			
Emission Factor Source[1]	Control Efficiency Basis[2]	Part 75 LME data			
NOx CONTROL DEVICE CODE[3]					
Avg. NOx CONTROL EFFICIENCY[4] = C.E.			%		%
NOx EMISSIONS[5]		11.5	tons NOx per yr	70	lbs NOx per day
SO2 EMISSION FACTOR (with units) = E. F.		LME			
Emission Factor Source[1]	Control Efficiency Basis[2]	Part 75 LME data			
FUEL PARAMETER (% ash or % sulfur) = FP			%		
SO2 CONTROL DEVICE CODE[3]					
Avg. SO2 CONTROL EFFICIENCY[4] = C.E.			%		
SO2 EMISSIONS[5]		1.9	tons SO2 per yr		
PM10 EMISSION FACTOR (with units) = E. F.		1.2E-02	lb/mmBtu		
Emission Factor Source[1]	Control Efficiency Basis[2]	AP-42 Table 3.1-2a			
FUEL PARAMETER (% ash or % sulfur) = FP			%		
PM10 CONTROL DEVICE CODE[3]					
Avg. PM10 CONTROL EFFICIENCY[4] = C.E.			%		
PM10 EMISSIONS[5]		0.40	tons PM10 per yr		
Pb EMISSION FACTOR (with units) = E. F.		1.4E-05	lb/mmBtu		
Emission Factor Source[1]	Control Efficiency Basis[2]	AP-42 Table 3.1-2a			
Pb CONTROL DEVICE CODE[3]					
Avg. Pb CONTROL EFFICIENCY[4] = C.E.			%		
Pb EMISSIONS[5]		5.0E-04	tons Pb per yr		

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2. **A** = Tested (by EPA Reference Method); **B** = Tested (other); **C** = Material balance**;** **D** = Design; O **=** Other (describe on separate sheet)
3. See 3-digit control device codes listed in appendix.
4. Note control efficiency will be zero if there is no control device **OR** the emission factor accounts for controls (i.e. EF is identified to be "with controls").
5. Annual Emissions = ANNUAL THRUPUT x EF x FP x (1/2000) x (100 - CE)/100; Ozone Emissions = DAILY THRUPUT x EF x FP x (100-CE)/100

2021 EMISSION CALCULATIONS
OPTION I: EMISSION FACTOR METHOD

REGISTRATION #: 61108 *REL. POINT NO.:* 3 *UNIT NO.:* 3 *PROCESS NO.:* 1, 3, 4 *SCC NO.:* 20100101

#3 Turbine - #2 Oil		ANNUAL		PEAK OZONE SEASON (JUNE, JULY, AUGUST)	
THRUPUT (with units)		69,451	mmBtu		
NO. OPERATING DAYS			days		
NO. OPERATING HOURS PER DAY			hours		
DAILY THRUPUT (with units) = Thruput/days		N/A			
TRS EMISSION FACTOR (with units) = E. F.					
Emission Factor Source[1]	Control Efficiency Basis[2]				
TRS CONTROL DEVICE CODE[3]					
Avg. TRS CONTROL EFFICIENCY[4] = C.E.			%		
5			tons TRS per yr		
PM EMISSION FACTOR (with units) = E. F.		1.2E-02	lb/mmBtu		
Emission Factor Source[1]	Control Efficiency Basis[2]	AP-42 Table 3.1-2a			
FUEL PARAMETER (% ash or % sulfur) = FP					
Total PM CONTROL DEVICE CODE[3]					
Avg. Total PM CONTROL EFFICIENCY[4] = C.E.			%		
Total PM EMISSIONS[5]		0.40	tons PM-Total per yr		
CO EMISSION FACTOR (with units) = E. F.		6E-03	lb/mmBtu		
Emission Factor Source[1]	Control Efficiency Basis[2]	ST			
CO CONTROL DEVICE CODE[3]					
Avg. CO CONTROL EFFICIENCY[4] = C.E.			%		
CO EMISSIONS[5]		0.21	tons CO per yr		
$PM_{2.5}$ EMISSION FACTOR (with units) = E. F.		1.2E-02	lb/mmBtu		
Emission Factor Source[1]	Control Efficiency Basis[2]	AP-42 Table 3.1-2a			
FUEL PARAMETER (% ash or % sulfur) = FP			%		
$PM_{2.5}$ CONTROL DEVICE CODE[2]					
Avg. $PM_{2.5}$ CONTROL EFFICIENCY[3] = C.E.			%		
$PM_{2.5}$ EMISSIONS[5]		0.40	tons $PM_{2.5}$ per yr		
NH_3 EMISSION FACTOR (with units) = E. F.		no factor			
Emission Factor Source[1]	Control Efficiency Basis[2]				
NH_3 CONTROL DEVICE CODE[3]					
Avg. NH_3 CONTROL EFFICIENCY[4] = C.E.			%		
NH_3 EMISSIONS[5]		0.00	tons NH_3 per yr		

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2. **A** = Tested (by EPA Reference Method); **B** = Tested (other); **C =** Material balance**;** **D** = Design; O **=** Other (describe on separate sheet)
3. See 3-digit control device codes listed in appendix.
4. Note control efficiency will be zero if there is no control device **OR** the emission factor accounts for controls (i.e. EF is identified to be "with controls").
5. Annual Emissions = ANNUAL THRUPUT x EF x FP x (1/2000) x (100 - CE)/100; Ozone Emissions = DAILY THRUPUT x EF x FP x (100-CE)/100

2021 EMISSION CALCULATIONS
OPTION I: EMISSION FACTOR METHOD

REGISTRATION #: 61108 *REL. POINT NO.:* 3 *UNIT NO.:* 3 *PROCESS NO.:* 1, 3, 4 *SCC NO.:* 20100101

#3 Turbine - #2 Oil		ANNUAL		PEAK OZONE SEASON (JUNE, JULY, AUGUST)	
THRUPUT (with units)		69,451	mmBtu		
NO. OPERATING DAYS			days		
NO. OPERATING HOURS PER DAY			hours		
DAILY THRUPUT (with units) = Thruput/days		N/A			
HAP EMISSION FACTOR (with units) = E. F.		9.94E-03	lb/mmBtu		
Emission Factor Source[1]	Control Efficiency Basis[2]	O - Southern Co. method			
HAP CONTROL DEVICE CODE[3]					
Avg. HAP CONTROL EFFICIENCY[4] = C.E.			%		
HAP (H2S04 mist) EMISSIONS[5]		0.35	tons per yr		
HAP EMISSION FACTOR (with units) = E. F.		<3.1E-07	lb/mmBtu		
Emission Factor Source[1]	Control Efficiency Basis[2]	AP-42, Table 3.1-5, 5th Ed 4/00			
HAP CONTROL DEVICE CODE[3]					
Avg. HAP CONTROL EFFICIENCY[4] = C.E.			%		
HAP (Beryllium) EMISSIONS[5]		1.1E-05	tons per yr		
HAP EMISSION FACTOR (with units) = E. F.					
Emission Factor Source[1]	Control Efficiency Basis[2]				
HAP CONTROL DEVICE CODE[3]					
Avg. HAP CONTROL EFFICIENCY[4] = C.E.			%		
HAP (____________) EMISSIONS[5]			tons per yr		
HAP EMISSION FACTOR (with units) = E. F.					
Emission Factor Source[1]	Control Efficiency Basis[2]				
HAP CONTROL DEVICE CODE[3]					
Avg. HAP CONTROL EFFICIENCY[4] = C.E.			%		
HAP (____________) EMISSIONS[5]			tons per yr		
HAP EMISSION FACTOR (with units) = E. F.					
Emission Factor Source[1]	Control Efficiency Basis[2]				
HAP CONTROL DEVICE CODE[3]					
Avg. HAP CONTROL EFFICIENCY[4] = C.E.			%		
HAP (____________) EMISSIONS[5]			tons per yr		
HAP EMISSION FACTOR (with units) = E. F.					
Emission Factor Source[1]	Control Efficiency Basis[2]				
HAP CONTROL DEVICE CODE[3]					
Avg. HAP CONTROL EFFICIENCY[4] = C.E.			%		
HAP (____________) EMISSIONS[5]			tons per yr		

1. **AP42; CEMS; ST** = Stack test; **F** = Federal factor (EPA standard factor); **O** = Other (describe on separate sheet)
2. **A** = Tested (by EPA Reference Method); **B** = Tested (other); **C =** Material balance**;** **D** = Design; O = Other (describe on separate sheet)
3. See 3-digit control device codes listed in appendix.
4. Note control efficiency will be zero if there is no control device **OR** the emission factor accounts for controls (i.e. EF is identified to be "with controls").
5. Annual Emissions = ANNUAL THRUPUT x EF x FP x (1/2000) x (100 - CE)/100; Ozone Emissions = DAILY THRUPUT x EF x FP x (100-CE)/100

2021 EMISSION CALCULATIONS
OPTION I: EMISSION FACTOR METHOD

REGISTRATION #: 61108 *REL. POINT NO.:* 3 *UNIT NO.:* 3 *PROCESS NO.:* 2 *SCC NO.:* 20100201

#3 Turbine - Nat. Gas		ANNUAL		PEAK OZONE SEASON (JUNE, JULY, AUGUST)	
THRUPUT (with units)		30,396	mmBtu	3,928	mmBtu
NO. OPERATING DAYS			days	92	days
NO. OPERATING HOURS PER DAY			hours	24	hours
DAILY THRUPUT (with units) = Thruput/days		N/A		43	mmBtu per day
VOC EMISSION FACTOR (with units) = E. F.		4.0E-04	lb/mmBtu		
Emission Factor Source[1]	Control Efficiency Basis[2]	ST			
VOC CONTROL DEVICE CODE[3]					
Avg. VOC CONTROL EFFICIENCY[4] = C.E.			%		%
VOC EMISSIONS[5]		0.01	tons VOC per yr	0.02	lbs VOC per day
NOx EMISSION FACTOR (with units) = E. F.		LME			
Emission Factor Source[1]	Control Efficiency Basis[2]	Part 75 LME data			
NOx CONTROL DEVICE CODE[3]					
Avg. NOx CONTROL EFFICIENCY[4] = C.E.			%		%
NOx EMISSIONS[5]		included with No.2 Oil		Inc. w/ No. 2 Oil	lbs NOx per day
SO2 EMISSION FACTOR (with units) = E. F.		LME			
Emission Factor Source[1]	Control Efficiency Basis[2]	Part 75 LME data			
FUEL PARAMETER (% ash or % sulfur) = FP			%		
SO2 CONTROL DEVICE CODE[3]					
Avg. SO2 CONTROL EFFICIENCY[4] = C.E.			%		
SO2 EMISSIONS[5]		included with No.2 Oil			
PM10 EMISSION FACTOR (with units) = E. F.		6.6E-03	lb/mmBtu		
Emission Factor Source[1]	Control Efficiency Basis[2]	AP-42 Table 3.1-2a			
FUEL PARAMETER (% ash or % sulfur) = FP			%		
PM10 CONTROL DEVICE CODE[3]					
Avg. PM10 CONTROL EFFICIENCY[4] = C.E.			%		
PM10 EMISSIONS[5]		0.10	tons PM10 per yr		
Pb EMISSION FACTOR (with units) = E. F.		no factor			
Emission Factor Source[1]	Control Efficiency Basis[2]				
Pb CONTROL DEVICE CODE[3]					
Avg. Pb CONTROL EFFICIENCY[4] = C.E.			%		
Pb EMISSIONS[5]		0.00	tons Pb per yr		

1. **AP42; CEMS; ST** = Stack test; **F** = Federal factor (EPA standard factor); **O** = Other (describe on separate sheet)
2. **A** = Tested (by EPA Reference Method); **B** = Tested (other); **C** = Material balance**;** **D** = Design; O **=** Other (describe on separate sheet)
3. See 3-digit control device codes listed in appendix.
4. Note control efficiency will be zero if there is no control device **OR** the emission factor accounts for controls (i.e. EF is identified to be "with controls").
5. Annual Emissions = ANNUAL THRUPUT x EF x FP x (1/2000) x (100 - CE)/100; Ozone Emissions = DAILY THRUPUT x EF x FP x (100-CE)/100

2021 EMISSION CALCULATIONS
OPTION I: EMISSION FACTOR METHOD

REGISTRATION #: 61108 *REL. POINT NO.:* 3 *UNIT NO.:* 3 *PROCESS NO.:* 2 *SCC NO.:* 20100201

#3 Turbine - Nat. Gas		ANNUAL		PEAK OZONE SEASON (JUNE, JULY, AUGUST)	
THRUPUT (with units)		30,396	mmBtu		
NO. OPERATING DAYS			days		
NO. OPERATING HOURS PER DAY			hours		
DAILY THRUPUT (with units) = Thruput/days		N/A			
TRS EMISSION FACTOR (with units) = E. F.					
Emission Factor Source[1]	Control Efficiency Basis[2]				
TRS CONTROL DEVICE CODE[3]					
Avg. TRS CONTROL EFFICIENCY[4] = C.E.			%		
5			tons TRS per yr		
PM-Total EMISSION FACTOR (with units) = E. F.		6.6E-03	lb/mmBtu		
Emission Factor Source[1]	Control Efficiency Basis[2]	AP-42 (Table 3.1-2a)			
FUEL PARAMETER (% ash or % sulfur) = FP					
PM-Total CONTROL DEVICE CODE[3]					
Avg. PM-Total CONTROL EFFICIENCY[4] = C.E.			%		
PM-Total EMISSIONS[5]		0.10	tons PM-Total per yr		
CO EMISSION FACTOR (with units) = E. F.		2.4E-02	lb/mmBtu		
Emission Factor Source[1]	Control Efficiency Basis[2]	ST			
CO CONTROL DEVICE CODE[3]					
Avg. CO CONTROL EFFICIENCY[4] = C.E.			%		
CO EMISSIONS[5]		0.36	tons CO per yr		
$PM_{2.5}$ EMISSION FACTOR (with units) = E. F.		6.6E-03	lb/mmBtu		
Emission Factor Source[1]	Control Efficiency Basis[2]	AP-42 Table 3.1-2a			
FUEL PARAMETER (% ash or % sulfur) = FP			%		
$PM_{2.5}$ CONTROL DEVICE CODE[2]					
Avg. $PM_{2.5}$ CONTROL EFFICIENCY[3] = C.E.			%		
$PM_{2.5}$ EMISSIONS[5]		0.10	tons $PM_{2.5}$ per yr		
NH_3 EMISSION FACTOR (with units) = E. F.		no factor			
Emission Factor Source[1]	Control Efficiency Basis[2]				
NH_3 CONTROL DEVICE CODE[3]					
Avg. NH_3 CONTROL EFFICIENCY[4] = C.E.			%		
NH_3 EMISSIONS[5]		0.00	tons NH_3 per yr		

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2. **A** = Tested (by EPA Reference Method); **B** = Tested (other); **C =** Material balance**;** **D** = Design; O **=** Other (describe on separate sheet)
3. See 3-digit control device codes listed in appendix.
4. Note control efficiency will be zero if there is no control device **OR** the emission factor accounts for controls (i.e. EF is identified to be "with controls").
5. Annual Emissions = ANNUAL THRUPUT x EF x FP x (1/2000) x (100 - CE)/100; Ozone Emissions = DAILY THRUPUT x EF x FP x (100-CE)/100

2021 EMISSION CALCULATIONS
OPTION I: EMISSION FACTOR METHOD

REGISTRATION #: 61108 *REL. POINT NO.:* 3 *UNIT NO.:* 3 *PROCESS NO.:* 2 *SCC NO.:* 20100201

#3 Turbine - Nat. Gas		ANNUAL		PEAK OZONE SEASON (JUNE, JULY, AUGUST)	
THRUPUT (with units)		30,396	mmBtu		
NO. OPERATING DAYS			days		
NO. OPERATING HOURS PER DAY			hours		
DAILY THRUPUT (with units) = Thruput/days		N/A			
HAP EMISSION FACTOR (with units) = E. F.		3.28E-04	lb/mmBtu		
Emission Factor Source[1]	Control Efficiency Basis[2]	O - Southern Co. method			
HAP CONTROL DEVICE CODE[3]					
Avg. HAP CONTROL EFFICIENCY[4] = C.E.			%		
HAP (H2S04 mist) EMISSIONS[5]		0.01	tons per yr		
HAP EMISSION FACTOR (with units) = E. F.		no factor			
Emission Factor Source[1]	Control Efficiency Basis[2]				
HAP CONTROL DEVICE CODE[3]					
Avg. HAP CONTROL EFFICIENCY[4] = C.E.			%		
HAP (Beryllium) EMISSIONS[5]		0.00	tons per yr		
HAP EMISSION FACTOR (with units) = E. F.					
Emission Factor Source[1]	Control Efficiency Basis[2]				
HAP CONTROL DEVICE CODE[3]					
Avg. HAP CONTROL EFFICIENCY[4] = C.E.			%		
HAP (________) EMISSIONS[5]			tons per yr		
HAP EMISSION FACTOR (with units) = E. F.					
Emission Factor Source[1]	Control Efficiency Basis[2]				
HAP CONTROL DEVICE CODE[3]					
Avg. HAP CONTROL EFFICIENCY[4] = C.E.			%		
HAP (________) EMISSIONS[5]			tons per yr		
HAP EMISSION FACTOR (with units) = E. F.					
Emission Factor Source[1]	Control Efficiency Basis[2]				
HAP CONTROL DEVICE CODE[3]					
Avg. HAP CONTROL EFFICIENCY[4] = C.E.			%		
HAP (________) EMISSIONS[5]			tons per yr		
HAP EMISSION FACTOR (with units) = E. F.					
Emission Factor Source[1]	Control Efficiency Basis[2]				
HAP CONTROL DEVICE CODE[3]					
Avg. HAP CONTROL EFFICIENCY[4] = C.E.			%		
HAP (________) EMISSIONS[5]			tons per yr		

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2. **A** = Tested (by EPA Reference Method); **B** = Tested (other); **C =** Material balance**;** **D** = Design; O = Other (describe on separate sheet)
3. See 3-digit control device codes listed in appendix.
4. Note control efficiency will be zero if there is no control device **OR** the emission factor accounts for controls (i.e. EF is identified to be "with controls").
5. Annual Emissions = ANNUAL THRUPUT x EF x FP x (1/2000) x (100 - CE)/100; Ozone Emissions = DAILY THRUPUT x EF x FP x (100-CE)/100