COMMONWEALTH of VIRGINIA

DEPARTMENT OF ENVIRONMENTAL QUALITY

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STATEMENT OF LEGAL AND FACTUAL BASIS

Virginia Electric and Power Company
Dominion Ladysmith Combustion Turbine Station
Caroline County, Virginia
Permit No. NRO40960

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. As required by 40 CFR Part 70, 9 VAC 5 Chapter 80, Article 3 of the Commonwealth of Virginia Regulations for the Control and Abatement of Air Pollution, Virginia Electric & Power Company has applied for a renewal of its Federal Operating Permit for its Ladysmith Combustion Turbine electric generation facility. The Department has reviewed the application and has prepared a draft Federal Operating Permit. This permit is based upon Federal Clean Air Act Phase II Acid Rain permitting requirements of Title IV, federal operating permit requirements of Title V, 40 CFR Part 97 (Subparts AAAAA – CCCCC, as amended), and Chapter 80, Article 3 of the Commonwealth of Virginia Regulations for the Control and Abatement of Air Pollution.

Engineer / Permit Contact: ______________________________ Date: ______________
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FACILITY INFORMATION

Permittee
Virginia Electric & Power Company aka Dominion
5000 Dominion Boulevard
Glen Allen, Virginia 23060

Facility
Dominion – Ladysmith Combustion Turbine Station
8063 Cedon Road
Woodford, Virginia 22580

Plant ID No. 51-033-0040

SOURCE DESCRIPTION

Facility Description: NAICS Code 221112 (Electric Power Generation)

Dominion operates five simple-cycle dual fuel combustion turbines (CTs) designated as Unit 1, Unit 2, Unit 3, Unit 4, and Unit 5. The CTs are used for providing additional power during times of high electrical demand. Pipeline natural gas is the primary fuel with No. 2 distillate fuel oil as the backup fuel. In addition to the five combustion turbines, the facility also operates two natural gas-fired pipeline heaters (PH-3 and PH-4), and three diesel-fired emergency engine-generator sets (EDG1, EDG2, and EDG3).

Unit 1 and Unit 2 each commenced construction in the year 2000, and commenced operation in May 2001; Units 1 and 2 are each subject to the requirements of 40 CFR 60, Subpart GG. Unit 3 and Unit 4 each commenced construction in 2007; Unit 3 commenced operation in May 2008, while Unit 4 commenced operation in June 2008. Units 3 and 4 are each subject to the requirements of 40 CFR 60, Subpart KKKK. Unit 5 was constructed between 2008 and 2009, and began operation in March 2009; Unit 5 is subject to the requirements of 40 CFR 60, Subpart KKKK.

This source is located in Caroline County, an attainment area for all pollutants, and is a synthetic minor source under the Prevention of Significant Deterioration (PSD) regulations (9 VAC 5-80 Article 8) through a minor New Source Review Permit, most recently amended on August 18, 2015. For the purposes of an Article 3 Federal Operating Permit program (9 VAC 5-80-360), the source is classified as a major source for NO_X emissions.

The facility is subject to the requirements of the Acid Rain permitting program and the Cross-State Air Pollution Rule (CSAPR). The NO_X Trading Program was applicable to the facility on May 31, 2004 and then replaced by the Clean Air Interstate Rule (CAIR) in 2005, which rendered the NO_X Trading Program no longer applicable. On December 23, 2008, the U.S.

Court of Appeals remanded CAIR to EPA. This action kept CAIR in force, but required EPA to develop a replacement rule, which addressed the courts order.

Effective January 1, 2015, the Cross-State Air Pollution Rule (CSAPR) took effect and replaced CAIR. 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 Acid Rain Renewal Application, dated June 18, 2014, was received by the DEQ on June 25, 2014. The CAIR Renewal Application, dated June 18, 2014, was received by the DEQ on June 25, 2014. However, as noted above, the CAIR program was replaced by CSAPR and so the CAIR Renewal Application is no longer applicable. The requirements of the Acid Rain Program and CSAPR Program are incorporated into the federal operating permit.

The facility has also applied for alternate-operating scenarios for re-tuning of the CTs and fuel type transfers. These alternate-operating scenarios were approved and will apply while firing on both pipeline natural gas and on No.2 distillate fuel oil.

In addition, the facility applied for a custom fuel monitoring schedule for Unit 1 and Unit 2 in a letter to the Environmental Protection Agency (EPA), Region III dated December 3, 2002. EPA approved the custom fuel monitoring schedule for Unit 1 and Unit 2 in a letter dated December 17, 2002. Both letters are attached as a part of Appendix A to the permit.

The natural gas-fired pipeline heater, PH-3, is rated at 10.75 MMBtu/hr, and is subject to the requirements of 40 CFR 60 Subpart Dc. The second natural gas-fired pipeline heater, PH-4, is rated at 4.2 MMBtu/hr.

The three emergency diesel-fired engine-generator sets, EDG1, EDG2, and EDG3, are each rated at 3,000 kilowatts, and are subject to the requirements of 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ.

COMPLIANCE STATUS

A full compliance evaluation of this facility, including a site visit, was last conducted on December 18, 2014. In addition, all reports and other data required by permit conditions or regulations, which are submitted to DEQ, are evaluated for compliance. Based on these compliance evaluations, the facility was not found to be in violation of any state or federal applicable requirements at this time.

CHANGES SINCE THE JULY 11, 2011 PERMITMODIFICATION

The following changes have been made to the Federal Operating Permit, dated October 1, 2010, as amended June 22, 2011 and July 11, 2011:

- *Emergency Engine-Generator Sets:* The requirements from the minor NSR permit, dated August 18, 2015, the requirements of 40 CFR 60 Subpart IIII, and the requirements of 40 CFR 63 Subpart ZZZZ are incorporated into the Title V renewal.

- *Phase II Acid Rain Permit:* The Phase II Acid Rain Permit was incorporated into the permit, and as an attachment to the permit.

- *Cross State Air Pollution Rule (CSAPR) Requirements:* CSAPR requirements are included as Conditions 132 through 141. The CSAPR program requirements are not currently part of the SAPCB Regulations. Consequently, the federal rule citations containing the applicable CSAPR requirements (40 CFR Part 97, Subparts AAAAA-CCCCC) are referenced in the permit.

These changes are discussed in more detail in the sections below.

EMISSION UNIT AND CONTROL DEVICE IDENTIFICATION

Equipment to be operated consists of:

Emission Unit ID	Stack ID	Emission Unit Description	Size/Rated Capacity[1] (P)-Primary Fuel (S) Secondary Fuel	Pollution Control Device Description[1] (PCD)	PCD ID [2, 3]	Pollutant Controlled	Applicable Permit Date
Fuel Burning Equipment / Utility Units							
Unit 1	1	The CT is a GE Model PG7241 (FA) simple cycle, duel fuel CT constructed in 2000 and commenced operation on May 31, 2001	1,761 MMBtu/hr on pipeline natural gas (P)[4]	When firing pipeline natural gas – dry low NO_X burners, each unit	CD_LN_01	Nitrogen Oxides (as NO_2)	8/18/15 NSR permit
Unit 1	1	The CT is a GE Model PG7241 (FA) simple cycle, duel fuel CT constructed in 2000 and commenced operation on May 31, 2001	1,910 MMBtu/hr on No.2 distillate fuel oil (S)[4]	When firing No.2 distillate fuel oil – water injection, each unit	CD_WI_01	Nitrogen Oxides (as NO_2)	8/18/15 NSR permit
Unit 2	2	The CT is a GE Model PG7241 (FA) simple cycle, duel fuel CT constructed in 2000 and commenced operation on May 23, 2001	1,761 MMBtu/hr on pipeline natural gas (P)[4]	When firing pipeline natural gas – dry low NO_X burners, each unit	CD_LN_02	Nitrogen Oxides (as NO_2)	8/18/15 NSR permit
Unit 2	2	The CT is a GE Model PG7241 (FA) simple cycle, duel fuel CT constructed in 2000 and commenced operation on May 23, 2001	1,910 MMBtu/hr on No.2 distillate fuel oil (S)[4]	When firing No.2 distillate fuel oil – water injection, each unit	CD_WI_02	Nitrogen Oxides (as NO_2)	8/18/15 NSR permit

Emission Unit ID	Stack ID	Emission Unit Description	Size/Rated Capacity[1] (P)-Primary Fuel (S) Secondary Fuel	Pollution Control Device Description[1] (PCD)	PCD ID [2, 3]	Pollutant Controlled	Applicable Permit Date
Unit 3	3	The CT is a GE Model PG7241 (FA) simple cycle, duel fuel CT constructed in 2007 and commenced operation on May 19, 2008	1,761 MMBtu/hr on pipeline natural gas (P)[4]	When firing pipeline natural gas – dry low NO_X burners, each unit	CD_LN_03	Nitrogen Oxides (as NO_2)	8/18/15 NSR permit
			1,910 MMBtu/hr on No.2 distillate fuel oil (S)[4]	When firing No.2 distillate fuel oil – water injection, each unit	CD_WI_03	Nitrogen Oxides (as NO_2)	
Unit 4	4	The CT is a GE Model PG7241 (FA) simple cycle, duel fuel CT constructed in 2007 and commenced operation on June 3, 2008	1,761 MMBtu/hr on pipeline natural gas (P)[4]	When firing pipeline natural gas – dry low NO_X burners, each unit	CD_LN_04	Nitrogen Oxides (as NO_2)	8/18/15 NSR permit
			1,910 MMBtu/hr on No.2 distillate fuel oil (S)[4]	When firing No.2 distillate fuel oil – water injection, each unit	CD_WI_04	Nitrogen Oxides (as NO_2)	

Emission Unit ID	Stack ID	Emission Unit Description	Size/Rated Capacity[1] (P)-Primary Fuel (S) Secondary Fuel	Pollution Control Device Description[1] (PCD)	PCD ID [2, 3]	Pollutant Controlled	Applicable Permit Date
Unit 5	5	The CT is a GE Model PG7241 (FA) simple cycle, duel fuel, CT constructed in 2008 and 2009 and commenced operational on March 5, 2009	1,761 MMBtu/hr on pipeline natural gas (P)[4]	When firing pipeline natural gas – dry low NO_X burners, each unit	CD_LN_05	Nitrogen Oxides (as NO_2)	8/18/15 NSR permit
			1,910 MMBtu/hr on No.2 distillate fuel oil (S)[4]	When firing No.2 distillate fuel oil – water injection, each unit	CD_WI_05	Nitrogen Oxides (as NO_2)	
PH-3	PHS3	Pipeline natural gas pipeline heaters. Constructed in 2007	10.75 MMBtu/hr	None	N/A	N/A	8/18/15 NSR permit
PH-4	PHS4	Pipeline natural gas pipeline heaters. Constructed in 2008	4.2 MMBtu/hr	None	N/A	N/A	8/18/15 NSR permit
EDG1	EDG1	Caterpillar C175-16 diesel engine-powered generator set	Engine output: 4,423 bhp Electrical output: 3,000 kW	None	N/A	N/A	8/18/15 NSR permit
EDG2	EDG2	Caterpillar C175-16 diesel engine-powered generator set	Engine output: 4,423 bhp Electrical output: 3,000 kW	None	N/A	N/A	8/18/15 NSR permit

Emission Unit ID	Stack ID	Emission Unit Description	Size/Rated Capacity[1] (P)-Primary Fuel (S) Secondary Fuel	Pollution Control Device Description[1] (PCD)	PCD ID [2, 3]	Pollutant Controlled	Applicable Permit Date
EDG3	EDG3	Caterpillar C175-16 diesel engine-powered generator set	Engine output: 4,423 bhp Electrical output: 3,000 kW	None	N/A	N/A	8/18/15 NSR permit
T1	--	Fixed roof storage tank for No. 2 distillate oil	2,700,000 gallons	None	N/A	N/A	8/18/15 NSR permit
T2	--	Fixed roof storage tank for No. 2 distillate oil	2,700,000 gallons	None	N/A	N/A	8/18/15 NSR permit

1. Specifications included in this section are for informational purposes only and do not form enforceable terms or conditions of the permit
2. CD_LN = dry low NO_X burner technology
3. CD_WI = water injection
4. These figures are based upon the manufacturer's specifications at 100% base load, 59°F and 14.7 psia.

EMISSIONS INVENTORY

Annual emissions summarized in the following table are derived in part from the 2014 CEDS emission report and information submitted by the facility. A copy of the report and information submitted by the facility are included as Attachment A.

2014 Pollutant Emissions (Plantwide Total)	
Pollutant	Tons Emitted
Criteria Pollutants	
PM-10	28.59
PM-2.5	28.59
VOC	7.62
NO_x	174.39
SO_2	17.71
CO	31.63
Lead (also a HAP)	0.0065
Hazardous Air Pollutants (HAPs) *	
Benzene	0.067
Formaldehyde	2.60

EMISSION UNIT APPLICABLE REQUIREMENTS

Fuel Burning Equipment: Units 1 through 5, PH-3 and PH-4

Limitations

The following limitations are state BACT requirements from the minor NSR permit issued on 8/18/15. The condition numbers below are from the NSR permit; a copy of the permit is enclosed in Attachment B.

Condition 1:	Nitrogen oxides (as NO_2) emissions from each CT shall be controlled by the utilization of a dry low NO_X combustor when firing natural gas, or water injection when firing No. 2 distillate fuel oil.
Condition 2:	Nitrogen oxides (as NO_2) emissions from each natural gas pipeline heater (PH3 and PH4) shall be controlled by the use of good combustion operating practices.
Condition 4:	Sulfur dioxide (SO_2) emissions from each CT shall be controlled by the use of pipeline quality natural gas as the primary and low sulfur No.2 distillate fuel oil as the secondary fuel; the condition also requires sulfur dioxide (SO_2) emissions from each pipeline heater be controlled by the use of pipeline quality natural gas.
Condition 6:	Particulate matter (PM-10) emissions from each CT, shall be controlled by the use of pipeline quality natural gas as the primary fuel and No.2 distillate fuel oil as the back-up fuel along with good combustion operating practices; the condition also requires particulate matter (PM-10) emissions from each pipeline heater shall be controlled by the use of pipeline quality natural gas and good combustion operating practices.
Condition 7:	Volatile organic compounds (VOC) and carbon monoxide (CO) emissions from each CT and pipeline heater shall be controlled by the use of good combustion operating practices.
Condition 13:	The condition establishes the approved fuels for the combustion turbines (Units 1 – 5).
Condition 14:	The condition establishes the approved fuel for the pipeline heaters (PH3 and PH4).
Condition 16:	The condition establishes the natural gas sulfur content for combustion turbines, Units 1 and 2.

Condition 17: The condition establishes the natural gas sulfur content for combustion turbines, Units 3 through 5, and pipelines heaters PH3 and PH4.

Condition 18: The condition establishes the distillate oil sulfur content for combustion turbines, Units 1 and 2.

Condition 19: The condition establishes the distillate oils sulfur content for combustion turbines, Units 3 through 5.

Condition 21: The two 2,700,000 gallon fixed-roof storage tanks (T1 and T2) shall be used to store only No.2 distillate fuel oil with a sulfur content not to exceed 0.05 percent by weight.

Condition 22: Except where this permit is more restrictive than the applicable requirement, Unit 1 and Unit 2 shall be operated in compliance with the requirements of40 CFR 60, Subpart GG – Standards of Performance for Stationary Gas Turbines and 40 CFR 60, Subpart A – General Provisions.

Condition 23: Except where this permit is more restrictive than the applicable requirement, Unit 3, Unit 4, and Unit 5 shall be operated in compliance with the requirements of40 CFR 60, Subpart KKKK – Standards of Performance for Stationary Combustion Turbines and 40 CFR 60, Subpart A – General Provisions.

Condition 24: Except where this permit is more restrictive than the applicable requirement, the pipeline heater (PH3) shall be operated in compliance with the requirements of 40 CFR, Subpart Dc (Standards of performance for Small Industrial-Commercial-Institutional Steam Generating Units).

Condition 25: The condition establishes the alternate operating scenarios for re-tuning Units 1 through 5.

Condition 26: The condition establishes the alternate operating scenarios for fuel type transfers for Units 1 through 5.

Condition 27: The condition establishes the alternate operating scenario for Low Load Emergency Mode for Unites 1 through 5.

Condition 28: The condition establishes the short-term emission limits for Units 1 and 2 while combusting natural gas.

Condition 29: The condition establishes the short-term emission limits for Units 3 through 5 while combusting natural gas.

Condition 30: The condition establishes the short-term emission limits for Units 1 and 2 while combusting distillate oil.

Condition 31: The condition establishes the short-term emission limits for Units 3 through 5 while combusting distillate oil.

Condition 32: The condition establishes the annual emission limitations for the five combustion turbines (Units 1 through 5).

Condition 33: The condition establishes the annual emission limitations for the Ladysmith Generation Facility.

Condition 34: The condition establishes the equation to account for fuel bound nitrogen (FBN) for Units 1 and 2, in accordance with 40 CFR 60 Subpart GG.

Condition 35: The condition establishes the visible emissions limit for the five combustion turbines (Units 1 through 5).

The following Virginia Administrative Codes that have specific emission requirements have been determined to be applicable:

9 VAC 5-50-80, Standard for Visible Emissions – The visible emission limitations in the NSR permit (dated 8/18/15) are more stringent than the visible emission standard in 9 VAC 5-50-80.

Monitoring and Recordkeeping

The following monitoring and recordkeeping requirements are taken from the minor NSR permit issued on 8/18/15. The condition numbers below are from the NSR permit; a copy of the permit is enclosed in Attachment B:

Condition 20: The condition establishes the fuel certification requirements for natural gas and distillate oil for Unites 1 through 5.

Condition 38: The condition requires the facility to use NO_X CEMS to demonstrate compliance with the NO_X emission limits for the five CTs.

Condition 39: The condition requires the facility to install and maintain NO_X

CEMS for the five CTs.

Condition 40: The condition establishes the minimum data capture requirements for the NO_X CEMS.

Condition 41: The condition establishes the data requirements in the event of NO_X CEMS failure.

Condition 43: The condition requires the installation of hourly fuel consumption monitors for the five CTs.

Condition 44: The condition establishes the requirements for visible emission observations for the five CTs.

Condition 48: The condition outlines the requirements for continuing compliance with the distillate oil sulfur content and natural gas sulfur content for the five CTs. The condition is streamlined with the requirements of 40 CFR 60 Subparts A and KKKK.

Condition 50: The condition establishes the recordkeeping requirements for the facility.

The compliance strategy for the facility includes continuous monitoring of NOx, proper operation and maintenance of the equipment, the use of low sulfur fuels, and good combustion practices. Attachment C provides emission factors and calculation methods used to calculate emissions.

The fuel certification requirements for both distillate oil and natural gas provide a means of demonstrating continuous compliance with the fuel sulfur limitations and sulfur dioxide emission limitations for the CTs (Units 1 through 5), and the pipeline heaters (PH3 and PH4). The facility is required to keep records of the fuel certifications, including purchase contracts, tariff sheets, or transportation contracts, to demonstrate continued compliance with the fuel certification requirements.

Condition 48 of the NSR permit, dated 8/18/15, establishes the fuel testing requirements to determine the distillate oil sulfur content prior to combustion. The condition further provides means of demonstrating continuous compliance with the fuel sulfur requirements for the CTs (Units 1 through 5) and sulfur dioxide limits in the permit.

The requirement to install instrumentation measuring the hourly fuel consumption for each CT (Units 1 through 5), in addition to the associated recordkeeping requirements, provides a means of demonstrating continuous compliance with hourly and annual emission limitations.

For the combustion turbines, a continuous emissions monitoring system (CEMS) is used to monitor NO_X and O_2 from all CT's, Unit 1 - Unit 5. The CEMS were installed to demonstrate compliance with emission standards of NSPS Subpart GG, Subpart KKKK, and BACT. The NO_X and O_2 monitors on each CT, Unit 1 - Unit 5, are used in lieu of monitoring the ratio of water to fuel, in accordance with 40 CFR 60, Subpart GG and 40 CFR 60, Subpart KKKK. The NO_X CEMS requirements for the CTs (Units 1 through 5) provide a means of demonstrating continuous compliance with short-term and annual NOx limits.

The primary fuel for each of the CTs is pipeline natural gas, with low sulfur No.2 distillate fuel oil to be used as a backup. The only fuel allowed for the pipeline heaters, PH-3 and PH-4, is pipeline quality natural gas. As long as the CTs and pipeline heaters are properly maintained and operated, PM10 emission limits, as well as opacity limits should not be violated. The permit conditions requiring proper operation and maintenance of the equipment, and records of maintenance and training, provide a reasonable assurance of compliance with the PM10 and opacity standards.

In addition to the operation and maintenance requirements, the facility is required to perform additional Visible Emission Observations on the CTs (Units 1 through 5), in accordance with Condition 44 of the NSR permit. The requirement for additional visible emission observations provides a means of demonstrating continuous compliance with the opacity limits for the CTs (Units 1 through 5).

Compliance with the visible emission limitations for any emissions unit may also be determined through visible emission evaluations, conducted upon request by the Department and/or the EPA.

Since the pipeline heaters (PH3 and PH4) only burn natural gas, the visible emission limitations established in 9 VAC 5-50-80 can easily be met on a continuous basis; no visible emission evaluations are required for the units. Periodic monitoring is satisfied by keeping records that only natural gas is burned. Compliance with the visible emission limitation in 9 VAC 5-50-80 may also be determined through visible emission evaluations, conducted upon request by the Department and/or the EPA.

The pipeline heater (PH3) is subject to NSPS Subpart Dc; however, since the unit is a 10.75 MMBtu/hr natural-gas fired unit, it is subject only to monitoring and recordkeeping requirements. Pipeline heater (PH4) is not subject to NSPS Subpart Dc due to the size of the unit. Condition 14 of the 8/18/15 NSR permit establishes natural gas as the approved fuel for both pipeline heaters; the recordkeeping requirement of Condition 50.c. (of the Article 3 permit) establishes compliance requirements to monitor fuel usage, found in §60.48c (g)(2).

Condition 50 of the NSR permit, dated 8/18/15, establishes the recordkeeping requirements necessary to demonstrate compliance with the limitations in the permit. Records of fuel type, fuel throughput, NOx CEMS data, and maintenance records, will provide assurance that the emission limits are not exceeded or identify any periods in which there may be an excursion.

Testing

The following testing requirement is from the NSR issued on 8/18/15; the condition number refers to the minor NSR permit:

Condition 45: Upon request by the DEQ, or in accordance with federal requirements, the permitted facility shall conduct additional performance tests to demonstrate compliance with the emission limits contained in this permit. The details of the tests shall be arranged with the DEQ.

In addition to the testing requirement from the NSR issued on 8/18/15, the following testing requirements were established in the Article 3 permit; condition numbers refer to the Article 3 permit:

Condition 43: The permit does not require source tests. The DEQ and EPA have the authority to require testing necessary to determine compliance with an emission limit or standard at any reasonable time.

Condition 45: If testing is conducted in addition to the monitoring specified in this permit, the permittee shall use the appropriate method(s) in accordance with procedures approved by the DEQ.

The requirement for subsequent visible emission observations was addressed in the monitoring and recordkeeping section above. The requirement for additional visible emission observations is provided as Condition 44 of the 8/18/15 NSR Permit.

The requirement for fuel sulfur testing, as provided in Condition 48 of the 8/18/15 NSR permit, is provided and discussed in the monitoring section above.

Compliance Assurance Monitoring (CAM)

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 Ladysmith Combustion Turbine Station is subject to the Acid Rain Program and CSAPR. In addition, Dominion Ladysmith Combustion Turbine Station employs a NO_X CEMS to ensure that the facility remains a minor source under PSD.

In addition, CAM is not applicable to pipeline heaters since each unit does not use a control device to meet the emission standards.

Reporting

The following reporting requirements are from the NSR issued on 8/18/15; condition numbers refer to the minor NSR permit:

Condition 25:	The condition establishes the reporting requirements for re-tuning events. This condition is combined with Condition 53 of the NSR permit.
Condition 42:	The condition establishes the reporting requirements for excess emission reports for the NO_X CEMS.
Condition 53:	The condition establishes the reporting requirements for re-tuning events. This condition is combined with Condition 25 of the NSR permit.
Condition 60:	The condition requires the facility to furnish notification of malfunctions of the affected facility or related air pollution control equipment that may cause excess emissions for more than one hour.
Condition 61:	The condition requires the facility to furnish notification to the DEQ of the intention to shut down or bypass, or both, air pollution control equipment for necessary scheduled maintenance, which may results in excess emissions for more than one hour, at least twenty-four hours prior to the shutdown.

In addition to the reporting requirements from the minor NSR permit (dated 8/18/15), the following reporting requirement has been included in the Article 3 permit; the condition number refers to the Article 3 permit condition:

Condition 46:	The condition establishes the submittal addresses for all permit related correspondence to the DEQ and EPA.

EMISSION UNIT APPLICABLE REQUIREMENTS

Emergency Engine-Generator Sets: EDG1, EDG2, and EDG3

Limitations

The following limitations are state BACT requirements from the minor NSR permit issued on 8/18/15. The condition numbers below are from the NSR permit; a copy of the permit is enclosed in Attachment B.

Condition 3: Nitrogen oxides (NO_X) emissions from the engine-generator sets (EDG1, EDG2 and EDG3) shall be controlled by turbocharged engine and after-cooler. The permittee shall maintain documentation that demonstrates that turbo-charging and after-cooling equipment has been installed on the engine-generator sets.

Condition 5: Sulfur dioxide (SO_2) emissions from the engine-generator sets (EDG1, EDG2 and EDG3) shall be controlled by the use of ultra low sulfur diesel (ULSD) fuel (maximum sulfur content ≤ 15 ppm).

Condition 8: Visible emissions from the engine-generator sets (EDG1, EDG2 and EDG3) shall be controlled by the use of good operating practices and performing appropriate maintenance in accordance with the manufacturer recommendations. In addition, the permittee may only change those settings that are permitted by the manufacturer and does not increase air emissions.

Condition 10: The permittee shall operate and maintain each engine-generator set (EDG1, EDG2 and EDG3) according to the manufacturer's written instructions or procedures developed by the permittee that are approved by the engine manufacturer. In addition, the permittee may only change those settings that are permitted by the manufacturer and does not increase air emissions. This condition has been streamlined with the requirements of 40 CFR 60.4206 and 40 CFR 60.4211.

Condition 11: The condition establishes that each engine-generator set (EDG1, EDG2 and EDG3) shall not operate more than 500 hours per year, calculated monthly as the sum of each consecutive 12 month period.

Condition 12: The condition establishes the approved operating scenarios for the engine-generator sets (EDG1, EDG2 and EDG3).

Condition 15: The condition specifies the diesel fuel specifications for the engine-generator sets (EDG1, EDG2 and EDG3). This condition is streamlined with the requirements of 40 CFR 60.4207.

Condition 20: The condition establishes the fuel certification requirements for the diesel fuel.

Condition 36: The condition establishes the hourly emission limitations for each engine-generator set, and the annual emission limitations for the three engine-generator sets combined.

Condition 37: The condition establishes the visible emissions limitation for each engine-generator set.

The emergency engine-generator sets (EDG1, EDG2, and EDG3) are subject to the requirements of 40 CFR 63 Subpart ZZZZ. The following conditions are established in the Article 3 permit; condition numbers referenced below refer to the Article 3 permit:

Condition 61: Except where this permit is more restrictive, the engine-generator sets (EDG1, EDG2, and EDG3) shall be operated in compliance with the requirements of 40 CFR 63, Subpart ZZZZ.

Condition 62: The engine-generator sets (EDG1, EDG2, and EDG3) must meet the requirements of 40 CFR 63 Subpart ZZZZ by meeting the requirements of 40 CFR 60, Subpart IIII.

The emergency engine-generator sets (EDG1, EDG2, and EDG3) are subject to the requirements of 40 CFR 60 Subpart IIII. The following conditions are established in the Article 3 permit; condition numbers referenced below refer to the Article 3 permit:

Condition 63: Except where this permit is more restrictive, the engine-generator sets (EDG1, EDG2, and EDG3) shall be operated in compliance with the requirements of 40 CFR 60, Subpart IIII.

Condition 64: The condition establishes the NSPS Subpart IIII limitations for the engine-generator sets (EDG1, EDG2, and EDG3).

Condition 65: The condition establishes the operational limitations for each of the engine-generator sets (EDG1, EDG2 and EDG3).

In addition to the limitations specified above, 40 CFR 60.4207 also establishes limitations on the diesel fuel sulfur content. The limitation on the sulfur content of the diesel fuel is streamlined with Condition 15 of the NSR permit issued on 8/18/15. The fuel certification necessary to demonstrate compliance with the diesel fuel limitation is streamlined with Condition 20 of the

NSR permit issued on 8/18/15.

In accordance with 40 CFR 60.4206 and 40 CFR 60.4211, the permittee must also maintain and operate each engine-generator set (EDG1, EDG2, and EDG3) according to the manufacturer's emission-related instructions or procedures developed by the permittee that are approved by the manufacturer, over the entire life of the engine. In addition, the permittee may only change those settings that are approved by the manufacturer. These requirements from the NSPS have been streamlined with Condition 10 of the NSR permit.

Monitoring and Recordkeeping
The following monitoring and recordkeeping requirements are taken from the minor NSR permit issued on 8/18/15. The condition numbers below are from the NSR permit; a copy of the permit is enclosed in Attachment B:

Condition 9:	The condition requires each engine-generator set (EDG1, EDG2, and EDG3) to be equipped with a non-resettable hour metering device to monitor the operating hours. The condition also requires monitoring and recording of the hours of operation of each engine-generator set. The condition is streamlined with the requirements of 40 CFR 60.4209.
Condition 67:	The condition establishes the recordkeeping requirements for the engine-generator sets (EDG1, EDG2, and EDG3). This condition is streamlined with the requirements of 40 CFR 60.4214.

The requirement to install a non-resettable hour meter on each engine-generator set establishes a means of demonstrating compliance with the limitations on the operation of each emergency engine-generator set in addition to the annual emission limitations. The non-resettable hour meter requirement is streamlined with the requirements from 40 CFR 60.4209.

The recordkeeping requirements include:

- <u>Annual hours of operation of each engine-generator set</u>: The recordkeeping requirement establishes a means of demonstrating compliance with the annual emission limitations and the annual hours of operation limitation.
- <u>Fuel supplier certifications</u>: The fuel supplier certifications establish a means of demonstrating compliance with the emission limitations, fuel sulfur content, and hourly and annual SO_2 emission limitations. The fuel certifications also establish a means of demonstrating compliance with the NSPS fuel limitations in 40 CFR 60.4207.
- <u>Engine Information</u>: The required engine information detailed in the permit, establishes a means of demonstrating compliance with the NSPS limitations in 40 CFR 60.4205.
- <u>Manufacturer Data</u>: The required engine manufacturer data establishes a means of

demonstrating compliance with the NSPS emission limitations in 40 CFR 60.4205 and 40 CFR 60.4211.

- Manufacturer's Written Operating Instructions: Records of the manufacturer's written operating instructions establish a means of demonstrating compliance with the NSR permit requirements to install and operate the engine-generator sets in accordance with manufacturer's written instructions or procedures developed by the permittee that are approved by the engine manufacturer. The recordkeeping requirement also establishes a means of demonstrating compliance with the requirements of 40 CFR 60.4206 and 40 CFR 60.4211.
- Records of the reasons for operation: The records for the reason of operation of each engine-generator set establish a means of demonstrating compliance with operating limitations in 40 CFR 60.4211.
- Results of all stack tests and visible emission evaluations: This recordkeeping requirement establishes a means of demonstrating compliance with the testing requirements discussed below.

Testing
The following testing requirements from the minor NSR permit, issued on 8/18/15, are included in the Article 3 permit. The condition numbers below are from the NSR permit; a copy of the permit is enclosed in Attachment B:

Condition 45: Upon request by the DEQ, or in accordance with federal requirements, the permitted facility shall conduct additional performance tests to demonstrate compliance with the emission limits contained in this permit. The details of the tests shall be arranged with the DEQ.

Condition 46: The facility shall be constructed so as to allow for emissions testing upon reasonable notice at any time, using appropriate methods. Sampling ports shall be provided when requested at the appropriate locations and safe sampling platforms and access shall be provided.

Condition 47: Upon request by the DEQ, the permittee shall conduct a visible emissions evaluation (VEE) on the emergency engine-generator sets (EDG1, EDG2, and EDG3) in accordance with 40 CFR Part 60, Appendix A, Method 9, to demonstrate compliance with the applicable visible emission limits contained in this permit. The details of the VEE shall be arranged with the DEQ.

Reporting
The following reporting requirement from the minor NSR permit, issued on 8/18/15, is included in the Article 3 permit. The condition number below is from the NSR permit; a copy of the permit is enclosed in Attachment B:

Condition 52: The condition establishes the initial notification requirements for construction, anticipated start-up, and actual start-up of each engine-generator set.

The following reporting requirement is included from 40 CFR 60 Subpart IIII. The condition number below is from the Article 3 permit:

Condition 72: The condition establishes the reporting requirements from 40 CFR 60.4214(d) for the emergency engine-generator sets.

EMISSION UNIT APPLICABLE REQUIREMENTS

Facility-Wide Conditions

Limitations

The following facility-wide limitations are taken from the minor NSR permit issued on 8/18/15. The condition numbers below are taken from the NSR permit; a copy of the permit is enclosed in Attachment B:

Condition 44: The condition establishes the maintenance and operating procedures for the facility.

Condition 48: The permittee shall, upon request of the DEQ, reduce the level of operation or shut down a facility, as necessary to avoid violating any primary ambient air quality standard and shall not return to normal operation until such time as the ambient air quality standard will not be violated.

Monitoring and Recordkeeping

The following recordkeeping requirement is taken from the minor NSR permit issued on 8/18/15. The condition number below is taken from the NSR permit; a copy of the permit is enclosed in Attachment B:

Condition 38: The condition requires the facility to keep records of: scheduled and unscheduled maintenance, training, and operating procedures.

Testing

The following facility-wide testing requirements are established in the Article 3 Permit;

condition numbers refer to the Article 3 permit:

Condition 76: The permit does not require source tests. The DEQ and EPA has authority to require testing not included in this permit if necessary to determine compliance with an emission limit or standard at any reasonable time. The permitted facility shall be modified to allow for emissions testing at any time using appropriate methods. Upon request from the Department, test ports will be provided at the appropriate locations.

Condition 77: If testing is conducted in addition to the monitoring specified in this permit, the permittee shall use the appropriate method(s) in accordance with procedures approved by the DEQ.

GENERAL CONDITIONS

The permit contains general conditions required by 40 CFR Part 72 and 9 VAC 5-80-490, that apply to all acid rain operating permit 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, including those caused by upsets, within one business day.

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

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 issues Phase II Acid Rain permits pursuant to 9 VAC 5 Chapter 80, Article 3 of the Virginia Regulations for the Control and Abatement of Air Pollution (Article 3 Federal Operating Permits (FOP) for Acid Rain Sources).

The Phase II permit was incorporated into the draft FOP. Because the Ladysmith Combustion Turbine Station is not listed on Table 2 of 40 CFR 73.10, there are no SO2 allowance allocations for the years 2010 and beyond for Units 1 through 5. In addition, because the combustion turbines (Units 1 through 5) are fired with natural gas or No. 2 distillate fuel oil, they are not subject to NOx limitations under 40 CFR Part 76. The Phase II acid rain permit renewal portion of the Article 3 FOP, dated June 18, 2014, was received by the DEQ on June 25, 2014 and has an expiration date of December 31, 2020.

A copy of the Title IV Acid Rain Permit application is provided as Attachment E to the Permit, and Attachment D to the Statement of Basis.

CROSS STATE AIR POLLUTION RULE (CSAPR)

The applicable requirements of the Cross-State Air Pollution Rule (CSAPR) – also referred to as the Transport Rule (TR) - are incorporated into the permit (Conditions 132 through 141), utilizing the Template as provided in EPA's May 13, 2015, Memorandum (Title V Permit Guidance and Template for the Cross-State Air Pollution Rule). Specifically, the permittee is subject to the following CSAPR requirements: the TR NOx Annual Trading Program (40 CFR Part 97, Subpart AAAAA), the TR NOx Ozone Season Trading Program (40 CFR Part 97, Subpart BBBBB), and the TR SO_2 Group 1 Trading Program (40 CFR Part 97, Subpart CCCCC).

STATE ONLY APPLICABLE REQUIREMENTS

None were identified by the applicant.

FUTURE APPLICABLE REQUIREMENTS

None were identified by the applicant.

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 Article 3 permitting program.

As a result of several EPA actions regarding GHG under the CAA, emissions of GHG must be addressed for an Article 3 permit renewed after January 1, 2011. The current state minor NSR permit for the Ladysmith Combustion Turbine Station contains no GHG-specific applicable requirements and there have been no modifications at the facility requiring a PSD permit. Therefore, there are no applicable requirements for the facility specific to GHG.

Currently inapplicable requirements identified by the applicant include the following requirements:

40 CFR 60, Subpart Dc, Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units has been specifically identified as being not applicable to pipeline heater PH4. NSPS Subpart Dc applies to each steam generating unit for which construction, modification, or reconstruction is commenced after June 9, 1989 and that has a maximum design heat input 100 MMBtu/hr less, but greater than or equal 10 MMBtu/hr. Since the pipeline heater (PH-4) is only 4.2 MMBtu/hr, this does not apply.

40 CFR 60 Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984 has been identified as being not applicable to units T1 and T2 due to the low vapor pressure from each petroleum storage tank.

40 CFR 63Subpart YYYY, National Emission Standards for Hazardous Air Pollutants for Combustion Turbines is not applicable to the facility because the facility is not a major source of HAPs.

9 VAC 5 Chapter 80, Article 7, and 9 VAC 5 Chapter 60, Article 3, are not applicable to the facility because the facility is not a major source of HAPs.

40 CFR 68, Prevention of Accidental Chemical Releases is not applicable to the facility because any chemicals on site are below the threshold levels.

The facility did not identify any additional inapplicable requirements in their application.

In addition to the inapplicable requirements identified by the facility, the following requirements have been identified as inapplicable:

40 CFR 63, Subpart DDDDD, National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Major Sources has been identified as being not applicable to the facility. The facility is an area source of HAPs; therefore the Boiler MACT for Major Sources is not applicable.

40 CFR 63, Subpart JJJJJJ, National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources has been identified as being not applicable to the pipeline heaters (PH3 and PH4). The pipeline heaters (PH3 and PH4) are natural gas-fired, and are excluded from MACT Subpart JJJJJJ.

COMPLIANCE PLAN

No compliance plan was included in the application or in the permit.

INSIGNIFICANT EMISSION 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 9 VAC 5-80-490.

There are no insignificant emission units included in the permit; the two tanks (T1 and T2) listed as insignificant emission units in the permit application have applicable requirements in the minor NSR permit issued on 8/18/15 and therefore cannot be considered insignificant emission units.

CONFIDENTIAL INFORMATION

The permittee did not submit a request for confidentiality. All portions of the permit application are suitable for public review.

PUBLIC PARTICIPATION

A public notice regarding the draft permit was placed in the *Free Lance-Star* newspaper, in Fredericksburg, Virginia, on February 12, 2016. All persons on the Title V mailing list were sent a copy of the public notice by either electronic mail or in letters on February 12, 2016. The affected state of Maryland and the District of Columbia were sent a copy of the public notice by either electronic mail or in letter on February 12, 2016.

The 30-day public comment period ran from February 12, 2016 to March 14, 2016. Comments from the facility were received on March 14, 2016. Based on the comments from the facility minor changes to the proposed Title V permit were made. The comments from the facility were administrative or clarifications and do not require additional public participation; all comments are available as part of the permitting file.

The EPA was sent a copy of the draft permit and notified of the public notice on February 10, 2016. Comments from EPA were received on March 29, 2016, and addressed; comments from the EPA do not require additional public participation. All comments are available as part of the permitting file.

ATTACHMENTS

Attachment A - 2014 Annual Emissions Update

Attachment B - Minor NSR Permit dated August 18, 2015

Attachment C - Emission Factors and Calculation Methods

Attachment D - Title IV Acid Rain Permit Application

Attachment A

2014 Annual Emissions Update

Northern Regional Office
13901 Crown Court, Woodbridge, VA22193 22193

Phone #: (703) 583-3800

Registration #: 40960
Site Name: Dominion - Ladysmith CT Station
Address: 8063 Cedon Rd, Woodford, VA 22580
Contact: Scott Lawton:

Report #: 303528
CMS: Title V Major
Classification: Major/Potential Major

AIR INSPECTION REPORT

The purpose of this inspection report is to document DEQ's observations and provide the compliance status for requirements applicable to the facility. Presented below are the following:

- **Inspection Details** describe this inspection report
- **Compliance Summary** lists individual requirements addressed in the report
- **Inspection Summary** provides an overview of the inspector's observations
- **Inspection Checklist** provides additional details and individual observations related to specific requirements

Inspection Details

Inspection Date: **Apr 27, 2015**
Inspection Reason: **Review T5 Emissions Statement**
Reporting Period: **01/01/2014 - 12/31/2014**
Inspector: **Justin Wilkinson**
Inspection Result: **In Compliance**

Program Code	Subpart
SIP	
TITLE V	

Compliance Summary

In Compliance **The applicable requirements listed in the table below were confirmed during the inspection to be in compliance.**

Permit Effective Date or Regulation	Applicable Requirement
10/1/2010	VII.N
5/10/2011	25

Approvals

Inspector: Justin Wilkinson
Signed Date: Apr 27, 2015

4.29.15
Supervisor: Roland Hartshorn

Inspection Summary

On April 16, 2015, DEQ received the CY2014 Annual Update & Emissions Statement for Dominion's Ladysmith Combustion Turbine Station. The document was submitted in accordance with the requirements of 9 VAC 5-80-340 C. Based on a review of the document, the reported emissions appear to account for all significant emission activities at the facility. DEQ updated its CEDS database with the provided facility CY2014 throughput data (i.e., million BTUs heat input on natural gas and oil). The CEDS emission estimates and Dominion's reported emissions of significance (i.e., > 0.1 tons per year) are shown below:

Facility Calculations CEDS Estimates
-------------------- -------------
VOCs - 7.61 tons VOCs - 7.624 tons
NOx - 174.39 tons NOx - 174.393 tons
SO2 - 17.71 tons SO2 - 17.706 tons
PM10 - 28.36 tons PM10 - 28.592 tons
CO - 31.56 tons CO - 31.627 tons

The CY2014 Title V Permit Program Fee (emissions component) for this facility will be based on the CEDS estimates of the above pollutants, with the exception of carbon monoxide (CO) which is not currently a billable pollutant.

The CEDS inspection targeting data has been reviewed and updated as necessary to incorporate the estimated time to complete a full compliance evaluation of the facility, including periodic report reviews.

Attachment:
CY2014 Pollutant Emissions Report (2 pages)

Inspection Checklist

Effective Date: Oct 1, 2010 **Applicable Requirement #:** VII.N **Compliance Status:** In Compliance

Applicable Requirement

The owner of any source for which a permit under 9 VAC 5-80-360 through 9 VAC 5-80-700 was issued shall pay permit fees consistent with the requirements of 9 VAC 5-80-310 et seq. The actual emissions covered by the permit program fees for the preceding year shall be calculated by the owner and submitted to DEQ by April 15 of each year. The calculations and final amount of emissions are subject to verification and final determination by DEQ.
(9 VAC 5-80-490 H)

Observation

See Inspector Comments section of this inspection report.

Effective Date: May 10, 2011 **Applicable Requirement #:** 25 **Compliance Status:** In Compliance

Applicable Requirement

Annual Emission Limits - Facility wide

A. Total emissions from the combined operation of all the emissions sources at the Ladysmith Generation Facility (as referenced in Condition 1) shall not exceed the limits specified below:

PM-10 - 74.3 tons/year
Carbon Monoxide - 124.6 tons/year
Nitrogen Oxides - 248.2 tons/year (as NO2)
Sulfur Dioxide (SO2) - 74.4 tons/year
Volatile Organic Compounds (VOC) - 11.8 tons/year

B. The total annual emissions from facility shall be calculated monthly as the sum of each consecutive twelve-month period. Compliance for the consecutive twelve-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 eleven months.
(9 VAC 5-80-1180 and 9 VAC 5-50-260)

Observation

The CY2014 emissions reported by the facility were as follows:

VOCs - 7.61 tons
NOx - 174.39 tons
SO2 - 17.71 tons
PM10 - 28.36 tons
CO - 31.56 tons

The emission reported appear to be below the applicable limits specified by this condition.

Commonwealth of Virginia
Department of Environmental Quality

Registration Number: 40960

County - Plant ID: 033-00040

Plant Name: Dominion - Ladysmith CT Station

POLLUTANT EMISSIONS REPORT (PLANT) (Tons/Year)

Parameter List

Pollutant Type: All Pollutants

Years: 2009-2014

	BZ	CO	FORM	NH3	NO2	PB	PM	PM 10
2009	0.036	105.278	1.425	0.000	83.700	0.003	15.482	15.482
2010	0.071	44.802	3.187	0.000	183.950	0.005	33.009	33.009
2011	0.025	25.957	1.454	0.000	88.312	0.000	14.623	14.623
2012	0.037	25.826	2.195	0.000	106.020	0.000	20.876	20.876
2013	0.056	34.320	2.858	0.000	140.880	0.002	28.065	28.065
2014	0.067	31.627	2.601	0.000	174.393	0.006	28.592	28.592

Registration Number: 40960

County - Plant ID: 033-00040

Plant Name: Dominion - Ladysmith CT Station

POLLUTANT EMISSIONS REPORT (PLANT) (Tons/Year)

Parameter List

Pollutant Type: All Pollutants

Years: 2009-2014

	PM 2.5	SO2	VOC
2009	15.482	8.300	7.756
2010	33.009	14.623	9.444
2011	14.623	1.487	4.728
2012	20.876	1.538	6.751
2013	28.065	6.907	8.441
2014	28.592	17.706	7.624

Dominion Resource Services, Inc.
5000 Dominion Boulevard, Glen Allen, VA 23060
dom.com

Dominion®

U.S. MAIL - RETURN RECEIPT REQUESTED

VA DEPARTMENT OF ENVIRONMENTAL QUALITY
NORTHERN
APR 16 2015
REGIONAL OFFICE
510
WOODBRIDGE, VA

April 14, 2015

Mr. R. David Hartshorn
Regional Air Compliance Manager
Virginia Department of Environmental Quality
Northern Regional Office
13901 Crown Court
Woodbridge, VA 22193

Re: 2014 Air Emissions Statement and Annual Update
Dominion - Ladysmith CT Station
Registration No. 40960

Dear Mr. Hartshorn:

The 2014 Air Emissions Inventory and the Annual Update for Dominion's Ladysmith CT Station are enclosed, as required by DEQ.

If you have any questions or require any additional information, please contact Alan Ball at (804) 273-3912 or Wesley.A.Ball@dom.com.

Sincerely,

Scott Lawton
Director, Electric Environmental Business Support

enclosures

DEQ

VIRGINIA DEPARTMENT OF
ENVIRONMENTAL QUALITY

2014 EMISSION STATEMENT FORM

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

FACILITY NAME DOMINION - LADYSMITH CT STATION	**PLANT ID & REGISTRATION #** 40960
LOCATION ADDRESS 8063 Cedon Rd Woodford, VA 22580	**JURISDICTION** Caroline County
MAILING ADDRESS Dominion Innsbrook Technical Center 2NW Electric Environmental Business Support 5000 Dominion Blvd. Glen Allen, VA 23060	**ZIP CODE**
CONTACT PERSON Scott Lawton (804) 273-2600	**PRIMARY NAICS CODE** 221112 For Agency Use Only T5

FACILITY TOTALS *(Sum annual emissions for all emission points/segments from attached pages)*

	ANNUAL		OZONE SEASON
TOTAL VOC EMISSIONS FOR 2014	7.61	TONS/YR	LBS/DAY
TOTAL NOX EMISSIONS FOR 2014	174.39	TONS/YR	LBS/DAY
TOTAL SO2 EMISSIONS FOR 2014	17.71	TONS/YR	NA
TOTAL PM10 EMISSIONS FOR 2014	28.36	TONS/YR	NA
TOTAL PB EMISSIONS FOR 2014	0.01	TONS/YR	NA
TOTAL TRS EMISSIONS FOR 2014	N/A	TONS/YR	NA
TOTAL TNMOC EMISSIONS FOR 2014	N/A	TONS/YR	NA
TOTAL non-VOC/non-PM HAP EMISSIONS FOR 2014	N/A	TONS/YR	NA
TOTAL CO EMISSIONS FOR 2014	31.56	TONS/YR	NA
TOTAL PM2.5 EMISSIONS FOR 2014	28.36	TONS/YR	NA
TOTAL NH3 EMISSIONS FOR 2014	0.00	TONS/YR	NA

PLEASE ATTACH "ANNUAL UPDATE" FORM.
PLEASE ATTACH "EMISSION STATEMENT CERTIFICATION FORM" with appropriate signature.

DEQ

VIRGINIA DEPARTMENT OF
ENVIRONMENTAL QUALITY

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.

(see reverse side for instructions)

SIGNATURE: Edward H. Baine **DATE:** 4/15/15

PRINTED NAME: Edward H. Baine

TITLE: Vice President - Power Generation System Operations

COMPANY: Dominion Generation

REGISTRATION NUMBER: 40960

TELEPHONE NUMBER: 804-273-3588

Dominion - Ladysmith CT Station
Registration # 40960
2014 Actual Emissions

Stk	Pt	Seg	Description	Fuel input		Pollutant	Factor	lb	tons
1	1	1	Simple Cycle CT - Nat Gas Fired	1,782,526	mmBTU fuel input	VOC	2.10E-03	3,743.30	1.87
SCC:	20100201					NOx	Included Below (with #2 Oil emissions)		
Note: All emission factor units are lb/mmBTU. All references to AP-42 are from AP-42, Chapter 3.1						SO2	Included Below (with #2 Oil emissions)		
(dated 4/2000). Emission factor sources:						PM10	6.60E-03	11,764.67	5.88
	NOx/SO2		CEMS			CO	9.04E-03	1,342.71	0.67
	CO		Stack Test Data (7/2001)			PM2.5	6.60E-03	11,764.67	5.88
	all others		AP-42			NH3	0.00	0.00	0.00
1	1	2	Simple Cycle CT - No. 2 Fired	204,567	mmBTU fuel input	VOC	4.10E-04	83.87	0.04
SCC:	20100101					NOx		85,400.00	42.70
Note: All emission factor units are lb/mmBTU. All references to AP-42 are from AP-42, Chapter 3.1						SO2		8,000.00	4.00
(dated 4/2000). Emission factor sources:						PM10	1.20E-02	2,352.52	1.18
	NOx/SO2		CEMS			Pb	1.40E-05	2.86	0.00
	CO		Stack Test Data (7/2001)			CO	1.77E-02	301.05	0.15
	all others		AP-42			PM2.5	1.20E-02	2,352.52	1.18
						NH3	0.00	0.00	0.00
2	2	1	Simple Cycle CT - Nat Gas Fired	1,487,999	mmBTU fuel input	VOC	2.10E-03	3,124.80	1.56
SCC:	20100201					NOx	Included Below (with #2 Oil emissions)		
Note: All emission factor units are lb/mmBTU. All references to AP-42 are from AP-42, Chapter 3.1						SO2	Included Below (with #2 Oil emissions)		
(dated 4/2000). Emission factor sources:						PM10	6.60E-03	9,820.79	4.91
	NOx/SO2		CEMS			CO	1.04E-02	1,285.63	0.64
	CO		Stack Test Data (7/2001)			PM2.5	6.60E-03	9,820.79	4.91
	all others		AP-42			NH3	0.00	0.00	0.00
2	2	2	Simple Cycle CT - No. 2 Fired	255,888	mmBTU fuel input	VOC	4.10E-04	104.91	0.05
SCC:	20100101					NOx		82,000.00	41.00
Note: All emission factor units are lb/mmBTU. All references to AP-42 are from AP-42, Chapter 3.1						SO2		9,600.00	4.80
(dated 4/2000). Emission factor sources:						PM10	1.20E-02	2,942.71	1.47
	NOx/SO2		CEMS			Pb	1.40E-05	3.58	0.00
	CO		Stack Test Data (7/2001)			CO	5.92E-02	1,261.37	0.63
	all others		AP-42			PM2.5	1.20E-02	2,942.71	1.47
						NH3	0.00	0.00	0.00

Dominion - Ladysmith CT Station
Registration # 40960
2014 Actual Emissions

Stk	Pt	Seg	Description	Fuel input		Pollutant	Factor	lb	tons
3	3	1	Simple Cycle CT - Nat Gas Fired	1,102,600	mmBTU fuel input	VOC	2.10E-03	2,315.46	1.16
SCC:	20100201					NOx	*Included Below (with #2 Oil emissions)*		
Note: All emission factor units are lb/mmBTU. All references to AP-42 are from AP-42, Chapter 3.1						SO2	*Included Below (with #2 Oil emissions)*		
(dated 4/2000). Emission factor sources:						PM10	6.60E-03	7,277.16	3.64
	NOx/SO2	CEMS				CO	1.80E-01	16,539.00	8.27
	all others	AP-42				PM2.5	6.60E-03	7,277.16	3.64
						NH3	0.00	0.00	0.00
3	3	2	Simple Cycle CT - No. 2 Fired	57,662	mmBTU fuel input	VOC	4.10E-04	23.64	0.01
SCC:	20100101					NOx		39,600.00	19.80
Note: All emission factor units are lb/mmBTU. All references to AP-42 are from AP-42, Chapter 3.1						SO2		1,800.00	0.90
(dated 4/2000). Emission factor sources:						PM10	1.20E-02	663.11	0.33
	NOx/SO2	CEMS				Pb	1.40E-05	0.81	0.00
	all others	AP-42				CO	9.12E-01	4,382.28	2.19
						PM2.5	1.20E-02	663.11	0.33
						NH3	0.00	0.00	0.00
4	4	1	Simple Cycle CT - Nat Gas Fired	1,197,983	mmBTU fuel input	VOC	2.10E-03	2,515.76	1.26
SCC:	20100201					NOx	*Included Below (with #2 Oil emissions)*		
Note: All emission factor units are lb/mmBTU. All references to AP-42 are from AP-42, Chapter 3.1						SO2	*Included Below (with #2 Oil emissions)*		
(dated 4/2000). Emission factor sources:						PM10	6.60E-03	7,906.68	3.95
	NOx/SO2	CEMS				CO	1.80E-01	17,969.74	8.98
	all others	AP-42				PM2.5	6.60E-03	7,906.68	3.95
						NH3	0.00	0.00	0.00
4	4	2	Simple Cycle CT - No. 2 Fired	230,650	mmBTU fuel input	VOC	4.10E-04	94.57	0.05
SCC:	20100101					NOx		66,400.00	33.20
Note: All emission factor units are lb/mmBTU. All references to AP-42 are from AP-42, Chapter 3.1						SO2		8,800.00	4.40
(dated 4/2000). Emission factor sources:						PM10	1.20E-02	2,652.47	1.33
	NOx/SO2	CEMS				Pb	1.40E-05	3.23	0.00
	all others	AP-42				CO	9.12E-01	17,529.38	8.76
						PM2.5	1.20E-02	2,652.47	1.33
						NH3	0.00	0.00	0.00

Dominion - Ladysmith CT Station
Registration # 40960
2014 Actual Emissions

Stk	Pt	Seg	Description	Amount	Units	Pollutant	Factor	lb	tons
5	5	1	Simple Cycle CT - Nat Gas Fired	1,388,860	mmBTU fuel input	VOC	2.10E-03	2,916.61	1.46
SCC:	20100201					NOx	*Included Below (with #2 Oil emissions)*		
Note:	All emission factor units are lb/mmBTU. All references to AP-42 are from AP-42, Chapter 3.1					SO2	*Included Below (with #2 Oil emissions)*		
(dated 4/2000). Emission factor sources:						PM10	6.60E-03	9,166.48	4.58
	NOx/SO2	CEMS				CO	7.20E-03	833.32	0.42
	CO		#REF!			PM2.5	6.60E-03	9,166.48	4.58
	all others	AP-42				NH3	0.00	0.00	0.00
5	5	2	Simple Cycle CT - No. 2 Fired	176,828	mmBTU fuel input	VOC	4.10E-04	72.50	0.04
SCC:	20100101					NOx		72,800.00	36.40
Note:	All emission factor units are lb/mmBTU. All references to AP-42 are from AP-42, Chapter 3.1					SO2		7,200.00	3.60
(dated 4/2000). Emission factor sources:						PM10	1.20E-02	2,033.52	1.02
	NOx/SO2	CEMS				Pb	1.40E-05	2.48	0.00
	CO		#REF!			CO	8.40E-03	123.78	0.06
	all others	AP-42				PM2.5	1.20E-02	2,033.52	1.02
						NH3	0.00	0.00	0.00
6	6	2	3 Million Gallon No. 2 F.O. AST	1,694.49	1000 Gal	VOC	5.82E-01	82.18	0.04
SCC:	40301020				Throughput				
Note:	All emission factor units are lb/1000 gal. Emission factor derived from Tanks 4.0 Program.								
7	7	2	3 Million Gallon No. 2 F.O. AST	1,694.49	1000 Gal	VOC	5.82E-01	82.18	0.04
SCC:	40301020				Throughput				
Note:	All emission factor units are lb/1000 gal. Emission factor derived from Tanks 4.0 Program.								
8	8	1	Pipeline Heater, Nat. Gas Fired	13,775	mmcf burned	VOC	2.80E+00	38.57	0.02
SCC:	39990003					NOx	1.40E+02	1,928.49	0.96
Note:	All emission factor units are lb/mmcf burned. All emission factors taken from AP-42, Chapter 1.4					SO2	6.00E-01	8.26	0.00
(dated 7/1998).						PM10	7.60E+00	104.69	0.05
	NOx/VOC	FIRE				Pb	5.00E-04	0.01	0.00
	all others	AP42				CO	8.40E+01	1,157.10	0.58
						PM2.5	7.60E+00	104.69	0.05

Dominion - Ladysmith CT Station
Registration # 40960
2014 Actual Emissions

Stk Pt Seg		Factor	lb	tons
9 9 1 Pipeline Heater, Nat. Gas Fired **4,692** mmcf burned	VOC	2.80E+00	13.14	0.01
SCC: 39990003	NOx	1.40E+02	656.90	0.33
Note: All emission factor units are lb/mmcf burned. All emission factors taken from AP-42, Chapter 1.4	SO2	6.00E-01	2.82	0.00
(dated 7/1998).	PM10	7.60E+00	35.66	0.02
NOx/VOC FIRE	Pb	5.00E-04	0.00	0.00
all others AP42	CO	8.40E+01	394.14	0.20
	PM2.5	7.60E+00	35.66	0.02
TOTALS	**VOC**	---	15,211.50	**7.61**
	NOx	---	348,785.40	**174.39**
	SO2	---	35,411.08	**17.71**
	PM10	---	56,720.47	**28.36**
	Pb	---	12.97	**0.0065**
	CO	---	63,119.50	**31.56**
	PM2.5	---	56,720.47	**28.36**
	NH3	---	0.00	**0.00**

Date : 12/16/2014 09:25 AM

Commonwealth of Virginia
Department of Environmental Quality

Annual Update for Calendar Year: 2014

Registration#:	40960
Plant Name:	Dominion - Ladysmith CT Station
Physical Location:	8063 Cedon Rd
Mailing Address:	5000 Dominion Blvd Glen Allen, VA 23060

Region:	NVRO
County:	033 Caroline County
Plant ID:	00040
Contact Person:	~~Taylor, Cathy~~ Lawton, Scott
Telephone:	(804)273-~~2020~~ 2600
Employees:	9
Principal Product:	Electricity
SIC:	4911 NAICS: 221112
Inspector:	Page, Tadric
Classification	Major/Potential Major

Summary Data for Calendar Year: ~~2013~~ 2014

Stk	Pt	Seg	Segment Description	SCC	Annual Thruput	Units	% Sulfur	% Ash	Heat Content (mmbtu/ SCC unit)	% Overall Effic	Primary Control Equip	Secondary Control Equip	% Annual Thruput Dec Feb	Mar May	Jun Aug	Sep Nov	Operating Schedule Hr Dy	Dy Wk	Hr Yr	% Space Heat	Stack Parameters Ht (ft)	Dia (ft)	Exit Temp (f)	Exit Flow Rate (ACFM)	Plume Ht (ft)	Elevation (ft)
1	1	1	Simple Cycle CT - Nat Gas Fired	20100201	~~1356502~~ 1782526	Million BTUs Fuel Input	.001		1025		205 205 = LOW NOX BURNERS		~~1~~ 12	~~7~~ 15	~~60~~ 57	~~32~~ 16	~~24~~ ✓	7	8760		65	18	1097	1142100		50
1	1	2	Simple Cycle CT - No. 2 Fired	20100101	~~76141~~ 204567	Million BTUs Fuel Input	.05	.01	138		028 028 = Steam or Water Injection		~~1~~	~~7~~	~~60~~	~~32~~	24	7	8760		65	18	1097	1142100		50
2	2	1	Simple Cycle CT - Nat Gas Fired	20100201	~~1186408~~ 1487999	Million BTUs Fuel Input	.001		1023		205 205 = LOW NOX BURNERS		~~1~~ 17	~~7~~ 15	~~60~~ 55	~~32~~ 13	~~24~~ ✓	7	8760		65	18	1097	1142100		50
2	2	2	Simple Cycle CT - No. 2 Fired	20100101	~~67150~~ 255888	Million BTUs Fuel Input	.05	.01	138		028 028 = Steam or Water Injection		~~1~~	~~7~~	~~60~~	~~32~~	24	7	8760		65	18	1097	1142100		50
3	3	1	Simple Cycle CT - Nat Gas Fired	20100201	~~1520011~~ 1,102,600	Million BTUs Fuel Input			1026		205 205 = LOW NOX BURNERS		~~1~~ 2	~~12~~ 19	~~54~~ 70	~~33~~ 9	24	7	8760		65	18	1116	1142100		50
3	3	2	Simple Cycle CT - No. 2 Fired	20100101	~~77579~~ 57662	Million BTUs Fuel Input	.05		138		028 028 = Steam or Water Injection		~~1~~	~~12~~	~~54~~	~~33~~	24	7	8760		65	18	1116	1142100		50
4	4	1	Simple Cycle CT - Nat Gas Fired	20100201	~~2018877~~ 1197983	Million BTUs Fuel Input			1025		205 205 = LOW NOX BURNERS		~~2~~ 20	~~16~~ 16	~~40~~ 55	~~33~~ 9	24	7	8760		65	18	1116	1142100		50
4	4	2	Simple Cycle CT - No. 2 Fired	20100101	~~51999~~ 230650	Million BTUs Fuel Input	.05		138		028 028 = Steam or Water Injection		~~2~~	~~16~~	~~40~~	~~33~~	24	7	8760		65	18	1116	1142100		50

Commonwealth of Virginia
Department of Environmental Quality

Annual Update for Calendar Year: 2014

Registration#:	40960
Plant Name:	Dominion - Ladysmith CT Station
Physical Location:	8063 Cedon Rd
Mailing Address:	5000 Dominion Blvd Glen Allen, VA 23060

Region:	NVRO
County:	033 Caroline County
Plant ID:	00040
Contact Person:	~~Taylor, Cathy~~ Lawton, Scott
Telephone:	(804)273-~~2020~~ 2600
Employees:	9
Principal Product:	Electricity
SIC:	4911 NAICS: 221112
Inspector:	Page, Tadric
Classification	Major/Potential Major

Summary Data for Calendar Year: ~~2013~~ 2014

													% Annual Thruput				Operating Schedule				Stack Parameters					
Stk	Pt	Seg	Segment Description	SCC	Annual Thruput	Units	% Sulfur	% Ash	Heat Content (mmbtu/ SCC unit)	% Overall Effic	Primary Control Equip	Secondary Control Equip	Dec Feb	Mar May	Jun Aug	Sep Nov	Hr Dy	Dy Wk	Hr Yr	% Space Heat	Ht (ft)	Dia (ft)	Exit Temp (f)	Exit Flow Rate (ACFM)	Plume Ht (ft)	Elevation (ft)
5	5	1	Simple Cycle CT - Nat Gas Fired	20100201	~~1049252~~ 1388860	Million BTUs Fuel Input			1026		205 205 = LOW NOX BURNERS		~~5~~ 15	~~10~~ 14	~~40~~ 60	~~20~~ 11	10	3	1640		65	26	1116	2140620		50
5	5	2	Simple Cycle CT - No. 2 Fired	20100101	~~28584~~ 176828	Million BTUs Fuel Input			138		028 028 = Steam or Water Injection		~~5~~	~~10~~	~~40~~	~~20~~	10	3	1640		65	26	1116	2140620		50
6	6	1	No. 2 Fuel Oil AST (Tank 1) - Storage Capacity	40301020	~~3000~~ ✓	1000 Gallons Storage Capacity							91	4	2	3	24	7	8760						50	
6	6	2	No. 2 Fuel Oil AST (Tank 1) - Throughput	40301021	~~510.2~~ 1,694.49	1000 Gallons Throughput							91	4	2	3	24	7	8760						50	
7	7	1	No. 2 Fuel Oil AST (Tank 2) - Storage Capacity	40301020	~~3000~~ ✓	1000 Gallons Storage Capacity							91	4	2	3	24	7	8760						50	
7	7	2	No. 2 Fuel Oil AST (Tank 2) - Throughput	40301021	~~519.2~~ 1,694.49	1000 Gallons Throughput							91	4	2	3	24	7	8760						50	
8	8	1	Pipeline Heater, Nat. Gas Fired	39990003	~~18~~ 13775	Million Cubic Feet Burned	.001		1025				2	13	53	32	24	7	8760						10	
9	9	1	Pipeline Heater, Nat. Gas Fired	39990003	~~6~~ 4692	Million Cubic Feet Burned	.001		1023				2	13	53	32	24	7	8760						10	

Commonwealth of Virginia
Department of Environmental Quality

Annual Update for Calendar Year: 2014

Registration#: 40960
Plant Name: Dominion - Ladysmith CT Station
Physical Location: 8063 Cedon Rd
Mailing Address: 5000 Dominion Blvd
Glen Allen, VA 23060

Region: NVRO
County: 033 Caroline County
Plant ID: 00040
Contact Person: ~~Taylor, Cathy~~ Lawton, Scott
Telephone: (804)273-~~2929~~ 2600
Employees: 9
Principal Product: Electricity
SIC: 4911 NAICS: 221112
Inspector: Page, Tadric
Classification Major/Potential Major

Summary Data for Calendar Year: ~~2010~~ 2014

												% Annual Thruput				Operating Schedule				Stack Parameters					
Stk	Pt	Seg	Segment Description	SCC	Annual Thruput	Units	% Sulfur	% Ash	Heat Content (mmbtu/ SCC unit)	% Overall Effic	Primary Control Equip	Secondary Control Equip	Dec Feb	Mar May	Jun Aug	Sep Nov	Hr Dy	Dy Wk	Hr Yr	% Space Heat	Ht (ft)	Dia (ft)	Exit Temp (f)	Exit Flow Rate (ACFM)	Plume Ht (ft)	Elevation (ft)

Document 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) Edward H. Baine

Title Vice President - Power Generation Systems Operations

Signature Edward H. Baine **Date** 4/15/15

Commonwealth of Virginia
Department of Environmental Quality
Consolidated Plant Emissions Report

Registration No: 40960
Plant Name: Dominion - Ladysmith CT Station
FIPS County Code: 033
Plant ID: 00040
Year of Emissions: 2014
Last Annual Update: 2013

GENERAL INFORMATION

Facility Name: Dominion - Ladysmith Combustion Turbine Station
Location Address:
Mailing Address:
Anuual Update Contact:
Phone Number:
Principal Product: Electricity
Comments:

UTM Zone: 18
UTM Vertical (KM): 4216.6
UTM Horizontal (KM): 279.5
Latitude: 38 o 4 ' 15 "
Longitude: -77 o 30 ' 49 "
Property Area (Acres): 0
No. of Employees: 9
Primary SIC Code: 4911

Facility Emissions

Pollutant	Emissions Value (tpy)	Allowable Value	Units
PM 10	28.5916504000		
PM	28.5916504000		
SO2	17.7055410000		
VOC	7.6235713750		
FORM	2.6011107400		
NO2	174.3929000000		
PM 2.5	28.5916504000		
CO	31.6274771000		
PB	0.0064837825		
BZ	0.0672136705		
NH3	0.0000000000		

STACK INFORMATION:

Number: 1
Description: Unit 1 Simple Cycle Combustion Turbine Exhaust

Stack Height(ft): 65
Stack Diameter(ft): 18
Exit Gas Temperature(F): 1097
Gas Flow Rate(ACFM): 1142100
Exit Gas Velocity(ft/sec): 74.8
Stack Type: V
Plume Height(ft): 0
Permitted Equipment: Y

UTM Zone: 18
UTM Vertical(KM): 4216.6
UTM Horizontal(KM): 279.55
GEP Stack Height: 0
GEP Building Height: 0
GEP Building Length: 0
GEP Bulding Width: 0
Rough Terrain: N
Elevation (ft above MSL): 50

Stack Emissions

Pollutant	Emissions Value (tpy)	Allowable Value	Units

BZ	0.0163207485
CO	0.8664356500
FORM	0.6614361100
NH3	0.0000000000
NO2	42.7000000000
PB	0.0014319690
PM	7.1097378000
PM 10	7.1097378000
PM 2.5	7.1097378000
SO2	4.0000000000
VOC	1.9135885350

POINT INFORMATION: Number: 1 Description: Unit 1 - Simple Cycle CT 1761 MMBtu/hr nat. gas, 1910 MMBtu/hr No. 2 F.O.

State Sensitive: N
Permitted Equipment: Y
Space Heat (%): 0

Design Capacity & Units: 1910 Per MILLION BTUS HOUR

% Throughput: DEC-FEB: 12 MAR-MAY: 15 JUN-AUG: 57 SEP-NOV: 16
Operating Schedule: Hours/Day: 24 Days/Week: 7 Hours/Year: 8760

Air Program	Sub Part
NSPS	GG
SIP	

Point Emissions

Pollutant	Emissions Value (tpy)	Allowable Value	Units
BZ	0.0163207485		
CO	0.8664356500		
FORM	0.6614361100		
NH3	0.0000000000		
NO2	42.7000000000		
PB	0.0014319690		
PM	7.1097378000		
PM 10	7.1097378000		
PM 2.5	7.1097378000		
SO2	4.0000000000		
VOC	1.9135885350		

SEGMENT INFORMATION: Number: 1 Description: Simple Cycle CT - Nat Gas Fired

Source Classification Code: 20100201
Actual Annual Throughput: 1782526
Max. Hourly Operation Rate: 1761
State Sensitive: N
Permitted Equipment: N

SCC Description: Turbine
SCC Units: Million BTUs Fuel Input
Trace%: 0 Ash%: 0 Sulfur%: .001
Heat Content (MMBTU): 1025

Insignificant Activity: N

Pollution Prevention: N

Throughput Limit:

Throughput Unit:

Pollution Prevention Comments:

Segment Comments:

Segment Emissions

Pollutant	Method	Factor	A/S/T	Primary Control	Secondary Control	Overall Efficiency %	Emissions Value (tpy)	Allowable Value	Units
NH3	Supplied factor (auto calc)	0.0000000000					0.00000000		
No factor available as of 5-24-04									
BZ	Federal factor (auto calc)	0.0000120000					0.01069515		
AP-42 (April 2000) Emission Factor Rating "A".									
FORM	Federal factor (auto calc)	0.0007100000					0.63279673		
AP-42 (April 2000) Emission Factor Rating "A".									
CO	Supplied factor (auto calc)	0.0008000000					0.71301040		
Factor taken from the emissions test peak load run; the heat input value was also taken from the peak load run.									
VOC	Federal factor (auto calc)	0.0021000000					1.87165230		
AP-42, Table 3.1-2a, 5th Ed 4/00									
PM	Federal factor (auto calc)	0.0066000000					5.88233580		
AP-42, Table 3.1-2a, 5th Ed 4/00									
PM 10	Supplied factor (auto calc)	0.0066000000					5.88233580		
Assume all PM is PM10.									
PM 2.5	Supplied factor (auto calc)	0.0066000000					5.88233580		
Assume all of PM10 is PM2.5									
NO2	Material balance (user calc)	0.0000000000		205			42.70000000		
CEMS Data (Note: the NOx emissions entered here includes the NOx from the "oil" segment as well).			205 = LOW NOX BURNERS						
SO2	Material balance (user calc)	0.0000000000					4.00000000		
SO2 emissions calculated by the CEM DAHS - Part 75, Appendix D, Eqn. D-5: SO2 #/hr = 0.0006 x Gas-MMBtu/hr Summed for the year. The SO2 emissions entered here includes the SO2 from the "oil" segment as well.									

SEGMENT INFORMATION: Number: 2 Description: Simple Cycle CT - No. 2 Fired

Source Classification Code:	20100101	SCC Description:	Turbine
Actual Annual Throughput:	204567	SCC Units:	Million BTUs Fuel Input
Max. Hourly Operation Rate:	1910	Trace%:	0 Ash%: .01 Sulfur%: .05
State Sensitive:	N	Heat Content (MMBTU):	138
Permitted Equipment:	N	Throughput Limit:	
Insignificant Activity:	N	Throughput Unit:	
Pollution Prevention:	N		

Pollution Prevention Comments:

Segment Comments:

Segment Emissions

Pollutant	Method	Factor	A/S/T	Primary Control	Secondary Control	Overall Efficiency %	Emissions Value (tpy)	Allowable Value	Units
NH3	Supplied factor (auto calc)	0.0000000000					0.00000000		
No emission factor/data available as of 5-24-04.									
PB	Federal factor (auto calc)	0.0000140000					0.00143196		
AP-42, Table 3.1-2a, 5th Ed 4/00									
BZ	Federal factor (auto calc)	0.0000550000					0.00562559		
AP-42 (April 2000) Emission Factor Rating "C".									
FORM	Federal factor (auto calc)	0.0002800000					0.02863938		
AP-42 (April 2000) Emission Factor Rating "B".									
VOC	Federal factor (auto calc)	0.0004100000					0.04193623		
AP-42, Table 3.1-2a, 5th Ed 4/00									
CO	Supplied factor (auto calc)	0.0015000000					0.15342525		
CO emission factor was taken from the emissions test peak load run; the heat input value was also taken from the peak load run.									
PM	Federal factor (auto calc)	0.0120000000					1.22740200		
AP-42, Table 3.1-2a, 5th Ed 4/00									
PM 10	Supplied factor (auto calc)	0.0120000000					1.22740200		
Assume all PM is PM10									
PM 2.5	Supplied factor (auto calc)	0.0120000000					1.22740200		
Assume all of PM10 is PM2.5									
NO2	Material balance (user calc)	0.0000000000		028			0.00000000		
NOx emissions from oil combustion included in NOx emissions entered in				028 = Steam or Water Injection					

"natural gas" segment.

SO2	Material balance (user calc)	0.0000000000	0.00000000

SO2 emissions from oil combustion included in SO2 emissions entered in "natural gas" segment. SO2 emissions calculated by the CEM DAHS - Part 75, Appendix D, Eqn. D-2: SO2 #/hr = 2.0 x Oil-lb/hr x %S/100 Summed for the year.

STACK INFORMATION: Number: 2 Description: Unit 2 Simple Cycle Combustion Turbine Exhaust

Stack Height(ft):	65	UTM Zone:	18
Stack Diameter(ft):	18	UTM Vertical(KM):	4216.6
Exit Gas Temperature(F):	1097	UTM Horizontal(KM):	279.55
Gas Flow Rate(ACFM):	1142100	GEP Stack Height:	0
Exit Gas Velocity(ft/sec):	74.8	GEP Building Height:	0
Stack Type:	V	GEP Building Length:	0
Plume Height(ft):	0	GEP Bulding Width:	0
Permitted Equipment:	Y	Rough Terrain:	N
		Elevation (ft above MSL):	50

Stack Emissions

Pollutant	Emissions Value (tpy)	Allowable Value	Units
BZ	0.0159649140		
CO	1.2965251500		
FORM	0.5640639650		
NH3	0.0000000000		
NO2	41.0000000000		
PB	0.0017912160		
PM	6.4457247000		
PM 10	6.4457247000		
PM 2.5	6.4457247000		
SO2	4.8000000000		
VOC	1.6148559900		

POINT INFORMATION: Number: 2 Description: Unit 2 - Simple Cycle CT 1761 MMBtu/hr nat. gas, 1910 MMBtu/hr No. 2 F.O.

Design Capacity & Units: 1910 MILLION BTUS Per HOUR

State Sensitive: N
Permitted Equipment: Y
Space Heat (%): 0

% Throughput: DEC-FEB: 17 MAR-MAY: 15 JUN-AUG: 55 SEP-NOV: 13

Operating Schedule: Hours/Day: 24 Days/Week: 7 Hours/Year: 8760

Air Program	Sub Part
NSPS	GG
SIP	

Point Emissions	Pollutant	Emissions Value (tpy)	Allowable Value	Units
	BZ	0.0159649140		
	CO	1.2965251500		
	FORM	0.5640639650		
	NH3	0.0000000000		
	NO2	41.0000000000		
	PB	0.0017912160		
	PM	6.4457247000		
	PM 10	6.4457247000		
	PM 2.5	6.4457247000		
	SO2	4.8000000000		
	VOC	1.6148559900		

SEGMENT INFORMATION: Number: 1 Description: Simple Cycle CT - Nat Gas Fired

Source Classification Code: 20100201
Actual Annual Throughput: 1487999
Max. Hourly Operation Rate: 1761
State Sensitive: N
Permitted Equipment: N
Insignificant Activity: N
Pollution Prevention: N

SCC Description: Turbine
SCC Units: Million BTUs Fuel Input
Trace%: 0 Ash%: 0 Sulfur%: .001
Heat Content (MMBTU): 1023
Throughput Limit:
Throughput Unit:

Pollution Prevention Comments:
Segment Comments:

Segment Emissions

Pollutant	Method	Factor	A/S/T	Primary Control	Secondary Control	Overall Efficiency %	Emissions Value (tpy)	Allowable Value	Units
BZ	Federal factor (auto calc)	0.0000120000					0.00892799		
AP-42 (April 2000) Emission Factor Rating "A".									
FORM	Federal factor (auto calc)	0.0007100000					0.52823964		
AP-42 (April 2000) Emission Factor Rating "A".									
CO	Supplied factor (auto calc)	0.0009000000					0.66959955		
CO emission factor was taken from the emissions test peak load run; the heat input value was also taken from the peak load run.									
VOC	Federal factor (auto calc)	0.0021000000					1.56239895		

AP-42, Table 3.1-2a, 5th Ed 4/00										
PM	Federal factor (auto calc)	0.0066000000					4.91039670			
AP-42, Table 3.1-2a, 5th Ed 4/00										
PM 10	Supplied factor (auto calc)	0.0066000000					4.91039670			
Assume all PM is PM10										
PM 2.5	Supplied factor (auto calc)	0.0066000000					4.91039670			
Assume all of PM10 is PM2.5.										
NO2	Material balance (user calc)	0.0000000000		205			41.00000000			
CEMS Data (Note: the NOx emissions entered here includes the NOx from the "oil" segment as well).				205 = LOW NOX BURNERS						
NH3	Material balance (user calc)	0.0000000000					0.00000000			
No emission factor/data available as of 5-24-04.										
SO2	Material balance (user calc)	0.0000000000					4.80000000			
SO2 emissions calculated by the CEM DAHS - Part 75, Appendix D, Eqn. D-5: SO2 #/hr = 0.0006 x Gas-MMBtu/hr Summed for the year. The SO2 emissions entered here includes the SO2 from the "oil" segment as well.										

SEGMENT INFORMATION: Number: 2 Description: Simple Cycle CT - No. 2 Fired

Source Classification Code:	20100101	SCC Description:	Turbine
Actual Annual Throughput:	255888		
Max. Hourly Operation Rate:	1910	SCC Units:	Million BTUs Fuel Input
State Sensitive:	N	Trace%:	0 Ash%: .01 Sulfur%: .05
Permitted Equipment:	N	Heat Content (MMBTU):	138
Insignificant Activity:	N	Throughput Limit:	
Pollution Prevention:	N	Throughput Unit:	

Pollution Prevention Comments:

Segment Comments:

Segment Emissions

Pollutant	Method	Factor	A/S/T	Primary Control	Secondary Control	Overall Efficiency %	Emissions Value (tpy)	Allowable Value	Units
PB	Federal factor (auto calc)	0.0000140000					0.00179121		
AP-42, Table 3.1-2a, 5th Ed 4/00									
BZ	Federal factor (auto calc)	0.0000550000					0.00703692		
AP-42 (April 2000) Emission Factor Rating "C".									
FORM	Federal factor (auto calc)	0.0002800000					0.03582432		

AP-42 (April 2000) Emission Factor Rating "B".

VOC	Federal factor (auto calc)	0.0004100000		0.05245704
AP-42, Table 3.1-2a, 5th Ed 4/00				
CO	Supplied factor (auto calc)	0.0049000000		0.62692560
CO emission factor was taken from the emissions test peak load run; the heat input value was also taken from the peak load run.				
PM	Federal factor (auto calc)	0.0120000000		1.53532800
AP-42, Table 3.1-2a, 5th Ed 4/00				
PM 10	Supplied factor (auto calc)	0.0120000000		1.53532800
Assume all PM is PM10				
PM 2.5	Supplied factor (auto calc)	0.0120000000		1.53532800
Assume all of PM10 is PM2.5.				
NO2	Material balance (user calc)	0.0000000000	028	0.00000000
NOx emissions from oil combustion included in NOx emissions entered in "natural gas" segment.			028 = Steam or Water Injection	
NH3	Material balance (user calc)	0.0000000000		0.00000000
No emission factor/data available as of 5-24-04.				
SO2	Material balance (user calc)	0.0000000000		0.00000000
SO2 emissions from oil combustion included in SO2 emissions entered in "natural gas" segment. SO2 emissions calculated by the CEM DAHS - Part 75, Appendix D, Eqn. D-2: SO2 #/hr = 2.0 x Oil-lb/hr x %S/100 Summed for the year.				

STACK INFORMATION: Number: 3 Description: Unit 3 Simple Cycle Combustion Turbine Exhaust

Stack Height(ft):	65	UTM Zone:	18
Stack Diameter(ft):	18	UTM Vertical(KM):	4216.6
Exit Gas Temperature(F):	1116	UTM Horizontal(KM):	279.55
Gas Flow Rate(ACFM):	1142100	GEP Stack Height:	0
Exit Gas Velocity(ft/sec):	74.8	GEP Building Height:	0
Stack Type:	V	GEP Building Length:	0
Plume Height(ft):	0	GEP Bulding Width:	0
Permitted Equipment:	Y	Rough Terrain:	N
		Elevation (ft above MSL):	50

Stack Emissions

Pollutant	Emissions Value (tpy)	Allowable Value	Units
BZ	0.0082013050		
CO	10.4606560000		
FORM	0.3994956800		
NO2	19.8000000000		
PB	0.0004036340		
PM	3.9845520000		

PM 10	3.9845520000
PM 2.5	3.9845520000
SO2	0.9000000000
VOC	1.1695507100

POINT INFORMATION: Number: 3 Description: Unit 3 - Simple Cycle CT 1761 MMBtu/hr nat. gas, 1910 MMBtu/hr No. 2 F.O.

State Sensitive: N
Permitted Equipment: Y
Space Heat (%): 0

Design Capacity & Units: 1910 MILLION BTUS Per HOUR

% Throughput: DEC-FEB: 2 MAR-MAY: 19 JUN-AUG: 70 SEP-NOV: 9

Operating Schedule: Hours/Day: 24 Days/Week: 7 Hours/Year: 8760

Air Program	Sub Part
NSPS	KKKK
SIP	

Point Emissions

Pollutant	Emissions Value (tpy)	Allowable Value	Units
BZ	0.0082013050		
CO	10.4606560000		
FORM	0.3994956800		
NO2	19.8000000000		
PB	0.0004036340		
PM	3.9845520000		
PM 10	3.9845520000		
PM 2.5	3.9845520000		
SO2	0.9000000000		
VOC	1.1695507100		

SEGMENT INFORMATION: Number: 1 Description: Simple Cycle CT - Nat Gas Fired

Source Classification Code: 20100201
Actual Annual Throughput: 1102600
Max. Hourly Operation Rate: 1761
State Sensitive: N
Permitted Equipment: N
Insignificant Activity: N
Pollution Prevention: N

SCC Description: Turbine
SCC Units: Million BTUs Fuel Input
Trace%: 0 Ash%: 0 Sulfur%: 0
Heat Content (MMBTU): 1026
Throughput Limit:
Throughput Unit:

Pollution Prevention Comments:
Segment Comments: Unit began commercial operations in CY2008

Segment Emissions

Pollutant	Method	Factor	A/S/T	Primary Control	Secondary Control	Overall Efficiency %	Emissions Value (tpy)	Allowable Value	Units
BZ	Federal factor (auto calc)	0.0000120000					0.00661560		
FORM	Federal factor (auto calc)	0.0007100000					0.39142300		
VOC	Federal factor (auto calc)	0.0021000000					1.15773000		
PM	Federal factor (auto calc)	0.0066000000					3.63858000		
PM 10	Supplied factor (auto calc)	0.0066000000					3.63858000		
PM 2.5	Supplied factor (auto calc)	0.0066000000					3.63858000		
CO	Supplied factor (auto calc)	0.0150000000					8.26950000		
AP-42, Table 3.1-1 (natural gas fired, Lean Pre Mix factor)									
NO2	Material balance (user calc)	0.0000000000		205			19.80000000		
NOx CEMS			205 = LOW NOX BURNERS						
SO2	Material balance (user calc)	0.0000000000					0.90000000		
Part 75, Appendix D: Optional SO2 Emissions Data Protocol for Gas-Fired and Oil-Fired Units									

SEGMENT INFORMATION: Number: 2 Description: Simple Cycle CT - No. 2 Fired

Source Classification Code:	20100101	SCC Description:	Turbine
Actual Annual Throughput:	57662	SCC Units:	Million BTUs Fuel Input
Max. Hourly Operation Rate:	1910		
State Sensitive:	N	Trace%:	0 Ash%: 0 Sulfur%: .05
Permitted Equipment:	N	Heat Content (MMBTU):	138
Insignificant Activity:	N	Throughput Limit:	
Pollution Prevention:	N	Throughput Unit:	

Pollution Prevention Comments:

Segment Comments: Unit began commercial operations in CY2008

Segment Emissions

Pollutant	Method	Factor	A/S/T	Primary Control	Secondary Control	Overall Efficiency %	Emissions Value (tpy)	Allowable Value	Units
PB	Federal factor (auto calc)	0.0000140000					0.00040363		
BZ	Federal factor (auto calc)	0.0000550000					0.00158570		
FORM	Federal factor (auto calc)	0.0002800000					0.00807268		
VOC	Federal factor (auto calc)	0.0004100000					0.01182071		
PM	Federal factor (auto calc)	0.0120000000					0.34597200		
PM 10	Supplied factor (auto calc)	0.0120000000					0.34597200		
PM 2.5	Supplied factor (auto calc)	0.0120000000					0.34597200		
CO	Supplied factor (auto calc)	0.0760000000					2.19115600		
AP-42, Table 3.1-1 (water/steam injection)									
NO2	Material balance (user calc)	0.0000000000		028			0.00000000		
NOx emissions from fuel oil combustion included in segment 1 reported emissions from this unit.			028 = Steam or Water Injection						
SO2	Material balance (user calc)	0.0000000000					0.00000000		
SO2 emissions from fuel oil combustion included in segment 1 reported emissions from this unit.									

STACK INFORMATION: Number: 4 Description: Unit 4 Simple Cycle Combustion Turbine Exhaust

Stack Height(ft):	65	UTM Zone:	18
Stack Diameter(ft):	18	UTM Vertical(KM):	4216.6
Exit Gas Temperature(F):	1116	UTM Horizontal(KM):	279.55
Gas Flow Rate(ACFM):	1142100	GEP Stack Height:	0
Exit Gas Velocity(ft/sec):	74.8	GEP Building Height:	0
Stack Type:	V	GEP Building Length:	0
Plume Height(ft):	0	GEP Bulding Width:	0
Permitted Equipment:	Y	Rough Terrain:	N
		Elevation (ft above MSL):	50

Stack Emissions

Pollutant	Emissions Value (tpy)	Allowable Value	Units
BZ	0.0135307730		
CO	17.7495725000		

FORM	0.4575749650
NO2	33.2000000000
PB	0.0016145500
PM	5.3372439000
PM 10	5.3372439000
PM 2.5	5.3372439000
SO2	4.4000000000
VOC	1.3051654000

POINT INFORMATION: Number: 4

Description: Unit 4 - Simple Cycle CT 1761 MMBtu/hr nat. gas, 1910 MMBtu/hr No. 2 F.O.

State Sensitive: N
Permitted Equipment: Y
Space Heat (%): 0

Design Capacity & Units: 1910 MILLION BTUS Per HOUR

% Throughput: DEC-FEB: 20 MAR-MAY: 16 JUN-AUG: 55 SEP-NOV: 9
Operating Schedule: Hours/Day: 24 Days/Week: 7 Hours/Year: 8760

Air Program	Sub Part
NSPS	KKKK
SIP	

Point Emissions

Pollutant	Emissions Value (tpy)	Allowable Value	Units
BZ	0.0135307730		
CO	17.7495725000		
FORM	0.4575749650		
NO2	33.2000000000		
PB	0.0016145500		
PM	5.3372439000		
PM 10	5.3372439000		
PM 2.5	5.3372439000		
SO2	4.4000000000		
VOC	1.3051654000		

SEGMENT INFORMATION: Number: 1

Description: Simple Cycle CT - Nat Gas Fired

Source Classification Code: 20100201
Actual Annual Throughput: 1197983
Max. Hourly Operation Rate: 1761
State Sensitive: N
Permitted Equipment: N
Insignificant Activity: N
Pollution Prevention: N

SCC Description: Turbine
SCC Units: Million BTUs Fuel Input
Trace%: 0 Ash%: 0 Sulfur%: 0
Heat Content (MMBTU): 1025
Throughput Limit:
Throughput Unit:

Pollution Prevention Comments:

Segment Comments: Each CT has CEM that records daily NOx emissions and will be used to provide annual NOx emission

Segment Emissions

Pollutant	Method	Factor	A/S/T	Primary Control	Secondary Control	Overall Efficiency %	Emissions Value (tpy)	Allowable Value	Units
BZ	Federal factor (auto calc)	0.0000120000					0.00718789		
FORM	Federal factor (auto calc)	0.0007100000					0.42528396		
VOC	Federal factor (auto calc)	0.0021000000					1.25788215		
PM	Federal factor (auto calc)	0.0066000000					3.95334390		
PM 10	Supplied factor (auto calc)	0.0066000000					3.95334390		
PM 2.5	Supplied factor (auto calc)	0.0066000000					3.95334390		
Assume all PM is PM2.5									
CO	Supplied factor (auto calc)	0.0150000000					8.98487250		
AP-42, Table 3.1-1 (natural gas fired, Lean Pre Mix factor)									
NO2	Material balance (user calc)	0.0000000000		205			33.20000000		
NOx CEMS			205 = LOW NOX BURNERS						
SO2	Material balance (user calc)	0.0000000000					4.40000000		
Part 75, Appendix D: Optional SO2 Emissions Data Protocol for Gas-Fired and Oil-Fired Units									

SEGMENT INFORMATION: Number: 2 Description: Simple Cycle CT - No. 2 Fired

Source Classification Code: 20100101
Actual Annual Throughput: 230650
Max. Hourly Operation Rate: 1910
State Sensitive: N
Permitted Equipment: N
Insignificant Activity: N
Pollution Prevention: N

SCC Description: Turbine
SCC Units: Million BTUs Fuel Input
Trace%: 0 Ash%: 0 Sulfur%: .05
Heat Content (MMBTU): 138
Throughput Limit:
Throughput Unit:

Pollution Prevention Comments:

Segment Comments: Each CT has CEM that records daily NOx emissions and will be used to provide annual NOx emission

Segment Emissions

Pollutant	Method	Factor	A/S/T	Primary Control	Secondary Control	Overall Efficiency %	Emissions Value (tpy)	Allowable Value	Units
PB	Federal factor (auto calc)	0.0000140000					0.00161455		
BZ	Federal factor (auto calc)	0.0000550000					0.00634287		
FORM	Federal factor (auto calc)	0.0002800000					0.03229100		
VOC	Federal factor (auto calc)	0.0004100000					0.04728325		
PM	Federal factor (auto calc)	0.0120000000					1.38390000		
PM 10	Federal factor (auto calc)	0.0120000000					1.38390000		
PM 2.5	Supplied factor (auto calc)	0.0120000000					1.38390000		
Assume all PM is PM2.5									
CO	Supplied factor (auto calc)	0.0760000000					8.76470000		
AP-42, Table 3.1-1 (water/steam injection)									
NO2	Material balance (user calc)	0.0000000000		028			0.00000000		
included in segment #1			028 = Steam or Water Injection						
SO2	Material balance (user calc)	0.0000000000					0.00000000		
included in segment #1									

STACK INFORMATION: Number: 5 Description: Unit 5 Simple Cycle Combustion Turbine Exhaust

Stack Height(ft):	65	UTM Zone:	18
Stack Diameter(ft):	26	UTM Vertical(KM):	4216.6
Exit Gas Temperature(F):	1116	UTM Horizontal(KM):	279.55
Gas Flow Rate(ACFM):	2140620	GEP Stack Height:	0
Exit Gas Velocity(ft/sec):	67.2	GEP Building Height:	0
Stack Type:	V	GEP Building Length:	0
Plume Height(ft):	0	GEP Bulding Width:	0
Permitted Equipment:	Y	Rough Terrain:	N
		Elevation (ft above MSL):	50

Stack Emissions

Pollutant	Emissions Value (tpy)	Allowable Value	Units

BZ	0.0131959300
CO	0.4785478000
FORM	0.5178012200
NO2	36.4000000000
PB	0.0012377960
PM	5.6442060000
PM 10	5.6442060000
PM 2.5	5.6442060000
SO2	3.6000000000
VOC	1.4945527400

POINT INFORMATION: Number: 5 Description: Unit 5 - Simple Cycle CT 1761, MMbtu/hr nat. gas, 1910 MMbut/hr No. 2 F.O.

State Sensitive: N
Permitted Equipment: Y
Space Heat (%): 0

Design Capacity & Units: 1910 MILLION BTUS Per HOUR

% Throughput: DEC-FEB: 15 MAR-MAY: 14 JUN-AUG: 60 SEP-NOV: 11
Operating Schedule: Hours/Day: 10 Days/Week: 3 Hours/Year: 1640

Air Program	Sub Part
NSPS	KKKK
SIP	

Point Emissions

Pollutant	Emissions Value (tpy)	Allowable Value	Units
BZ	0.0131959300		
CO	0.4785478000		
FORM	0.5178012200		
NO2	36.4000000000		
PB	0.0012377960		
PM	5.6442060000		
PM 10	5.6442060000		
PM 2.5	5.6442060000		
SO2	3.6000000000		
VOC	1.4945527400		

SEGMENT INFORMATION: Number: 1 Description: Simple Cycle CT - Nat Gas Fired

Source Classification Code: 20100201
Actual Annual Throughput: 1388860
Max. Hourly Operation Rate: 1761
State Sensitive: N
Permitted Equipment: N
Insignificant Activity: N
Pollution Prevention: N

SCC Description: Turbine
SCC Units: Million BTUs Fuel Input
Trace%: 0 Ash%: 0 Sulfur%: 0
Heat Content (MMBTU): 1026
Throughput Limit:

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Throughput Unit:

Pollution Prevention Comments:

Segment Comments: Unit commenced operation in CY2009

Segment Emissions

Pollutant	Method	Factor	A/S/T	Primary Control	Secondary Control	Overall Efficiency %	Emissions Value (tpy)	Allowable Value	Units
BZ	Federal factor (auto calc)	0.0000120000					0.00833316		
CO	Supplied factor (auto calc)	0.0006000000					0.41665800		
Stack Test April 2, 2009									
FORM	Federal factor (auto calc)	0.0007100000					0.49304530		
VOC	Federal factor (auto calc)	0.0021000000					1.45830300		
PM	Federal factor (auto calc)	0.0066000000					4.58323800		
PM 10	Supplied factor (auto calc)	0.0066000000					4.58323800		
PM 2.5	Supplied factor (auto calc)	0.0066000000					4.58323800		
NO2	Material balance (user calc)	0.0000000000		205			36.40000000		
Each CT has a CEMS that records daily NOx emissions. The CEMS will be used to provide annual NOx emissions. The NOx emissions entered here includes the NOx from the "oil" segment as well.				205 = LOW NOX BURNERS					
SO2	Material balance (user calc)	0.0000000000					3.60000000		
SO2 emissions are calculated by the CEMS DAHS - Part 75, Appendix D, Eqn. D-5: SO2 #/hr = 0.0006 x Gas-MMBtu/hr Summed for the year. The SO2 emissions entered here includes the SO2 from the "oil" segment as well.									

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SEGMENT INFORMATION: Number: 2 Description: Simple Cycle CT - No. 2 Fired

Source Classification Code: 20100101
Actual Annual Throughput: 176828
Max. Hourly Operation Rate: 1910
State Sensitive: N
Permitted Equipment: N
Insignificant Activity: N
Pollution Prevention: N

SCC Description: Turbine
SCC Units: Million BTUs Fuel Input
Trace%: 0 Ash%: 0 Sulfur%: 0
Heat Content (MMBTU): 138
Throughput Limit:
Throughput Unit:

Pollution Prevention Comments:
Segment Comments: Unit commenced operation in CY2009

Segment Emissions

Pollutant	Method	Factor	A/S/T	Primary Control	Secondary Control	Overall Efficiency %	Emissions Value (tpy)	Allowable Value	Units
PB	Federal factor (auto calc)	0.0000140000					0.00123779		
BZ	Federal factor (auto calc)	0.0000550000					0.00486277		
FORM	Federal factor (auto calc)	0.0002800000					0.02475592		
VOC	Federal factor (auto calc)	0.0004100000					0.03624974		
CO	Supplied factor (auto calc)	0.0007000000					0.06188980		

Stack Test April 2, 2009

Pollutant	Method	Factor	A/S/T	Primary Control	Secondary Control	Overall Efficiency %	Emissions Value (tpy)	Allowable Value	Units
PM	Federal factor (auto calc)	0.0120000000					1.06096800		
PM 10	Federal factor (auto calc)	0.0120000000					1.06096800		
PM 2.5	Supplied factor (auto calc)	0.0120000000					1.06096800		
NO2	Material balance (user calc)	0.0000000000		028			0.00000000		

Each CT has a CEMS that records daily NOx emissions. The CEMS will be used to provide annual NOx emission data. NOx emissions for segment 2 are included in segment 1.

028 = Steam or Water Injection

Pollutant	Method	Factor	A/S/T	Primary Control	Secondary Control	Overall Efficiency %	Emissions Value (tpy)	Allowable Value	Units
SO2	Material balance (user calc)	0.0000000000					0.00000000		

SO2 emissions are calculated by the CEMS DAHS - Part 75, Appendix D, Eqn. D-5: SO2 #/hr = 0.0006 x Gas-MMBtu/hr Summed for the year. SO2 emissions for segment 2 are included in segment 1.

STACK INFORMATION: Number: 6 Description: 3 Million Gallon AST (Tank 1), storing No. 2 Fuel Oil

Stack Height(ft):	0
Stack Diameter(ft):	0
Exit Gas Temperature(F):	0
Gas Flow Rate(ACFM):	0
Exit Gas Velocity(ft/sec):	0
Stack Type:	F
Plume Height(ft):	50
Permitted Equipment:	Y

UTM Zone:	18
UTM Vertical(KM):	4216.6
UTM Horizontal(KM):	279.55
GEP Stack Height:	0
GEP Building Height:	0
GEP Building Length:	0
GEP Bulding Width:	0
Rough Terrain:	N
Elevation (ft above MSL):	0

Stack Emissions	Pollutant	Emissions Value (tpy)	Allowable Value	Units
	VOC	0.0500000000		

POINT INFORMATION: Number: 6 Description: 3 Million Gallon AST (Tank 1), storing No. 2 Fuel Oil

Design Capacity & Units: 0 Per

% Throughput: DEC-FEB: 91 MAR-MAY: 4 JUN-AUG: 2 SEP-NOV: 3

Operating Schedule: Hours/Day: 24 Days/Week: 7 Hours/Year: 8760

State Sensitive:	N
Permitted Equipment:	N
Space Heat (%):	0
Air Program	Sub Part

Point Emissions	Pollutant	Emissions Value (tpy)	Allowable Value	Units
	VOC	0.0500000000		

SEGMENT INFORMATION: Number: 1 Description: No. 2 Fuel Oil AST (Tank 1) - Storage Capacity

Source Classification Code:	40301020
Actual Annual Throughput:	3000
Max. Hourly Operation Rate:	0
State Sensitive:	N
Permitted Equipment:	Y
Insignificant Activity:	N
Pollution Prevention:	N

SCC Description: Distillate Fuel #2: Breathing Loss (250000 Bbl. Tank Size)

SCC Units: 1000 Gallons Storage Capacity

Trace%: 0 Ash%: 0 Sulfur%: 0

Heat Content (MMBTU): 0

Throughput Limit:

Throughput Unit:

Pollution Prevention Comments:

Segment Comments: Reported throughput

Segment Emissions

Pollutant	Method	Factor	A/S/T	Primary Control	Secondary Control	Overall Efficiency %	Emissions Value (tpy)	Allowable Value	Units
VOC	Engr judgement (user calc)	0.0000000000					0.01000000		

Provided by source using EPA's TANKS 4.0 Program.

SEGMENT INFORMATION: Number: 2 Description: No. 2 Fuel Oil AST (Tank 1) - Throughput

Source Classification Code: 40301021
Actual Annual Throughput: 1694.49
Max. Hourly Operation Rate: 0
State Sensitive: N
Permitted Equipment: Y
Insignificant Activity: N
Pollution Prevention: N

SCC Description: Distillate Fuel #2: Working Loss (Tank Diameter Independent)
SCC Units: 1000 Gallons Throughput
Trace%: 0 Ash%: 0 Sulfur%: 0
Heat Content (MMBTU): 0
Throughput Limit:
Throughput Unit:

Pollution Prevention Comments:

Segment Comments: Reported throughput

Segment Emissions

Pollutant	Method	Factor	A/S/T	Primary Control	Secondary Control	Overall Efficiency %	Emissions Value (tpy)	Allowable Value	Units
VOC	Engr judgement (user calc)	0.0000000000					0.04000000		

EPA TANKS Program

STACK INFORMATION: Number: 7 Description: 3 Million Gallon AST (Tank 2), storing No. 2 Fuel Oil

Commonwealth of Virginia
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Stack Height(ft):	0	UTM Zone:	18
Stack Diameter(ft):	0	UTM Vertical(KM):	4216.6
Exit Gas Temperature(F):	0	UTM Horizontal(KM):	279.55
Gas Flow Rate(ACFM):	0	GEP Stack Height:	0
Exit Gas Velocity(ft/sec):	0	GEP Building Height:	0
Stack Type:	F	GEP Building Length:	0
Plume Height(ft):	50	GEP Bulding Width:	0
Permitted Equipment:	Y	Rough Terrain:	N
		Elevation (ft above MSL):	0

Stack Emissions Pollutant	Emissions Value (tpy)	Allowable Value	Units
VOC	0.0500000000		

POINT INFORMATION: Number: 7 Description: 3 Million Gallon AST (Tank 2), storing No. 2 Fuel Oil

Design Capacity & Units: 0 Per

State Sensitive: N
Permitted Equipment: N
Space Heat (%): 0
Air Program: Sub Part

% Throughput: DEC-FEB: 91 MAR-MAY: 4 JUN-AUG: 2 SEP-NOV: 3
Operating Schedule: Hours/Day: 24 Days/Week: 7 Hours/Year: 8760

Point Emissions Pollutant	Emissions Value (tpy)	Allowable Value	Units
VOC	0.0500000000		

SEGMENT INFORMATION: Number: 1 Description: No. 2 Fuel Oil AST (Tank 2) - Storage Capacity

Source Classification Code:	40301020	SCC Description:	Distillate Fuel #2: Breathing Loss (250000 Bbl. Tank Size)
Actual Annual Throughput:	3000	SCC Units:	1000 Gallons Storage Capacity
Max. Hourly Operation Rate:	0		
State Sensitive:	N	Trace%:	0 Ash%: 0 Sulfur%: 0
Permitted Equipment:	Y	Heat Content (MMBTU):	0
Insignificant Activity:	N	Throughput Limit:	
Pollution Prevention:	N	Throughput Unit:	

Pollution Prevention Comments:
Segment Comments:

Segment Emissions

Pollutant	Method	Factor	A/S/T	Primary Control	Secondary Control	Overall Efficiency %	Emissions Value (tpy)	Allowable Value	Units
VOC	Engr judgement (user calc)	0.0000000000					0.01000000		

Provided by source using EPA's TANKS 4.0 Program.

SEGMENT INFORMATION: Number: 2 Description: No. 2 Fuel Oil AST (Tank 2) - Throughput

Source Classification Code: 40301021
Actual Annual Throughput: 1694.49
Max. Hourly Operation Rate: 0
State Sensitive: N
Permitted Equipment: Y
Insignificant Activity: N
Pollution Prevention: N

SCC Description: Distillate Fuel #2: Working Loss (Tank Diameter Independent)
SCC Units: 1000 Gallons Throughput
Trace%: 0 Ash%: 0 Sulfur%: 0
Heat Content (MMBTU): 0
Throughput Limit:
Throughput Unit:

Pollution Prevention Comments:
Segment Comments:

Segment Emissions

Pollutant	Method	Factor	A/S/T	Primary Control	Secondary Control	Overall Efficiency %	Emissions Value (tpy)	Allowable Value	Units
VOC	Engr judgement (user calc)	0.0000000000					0.04000000		

EPA TANKS Program

STACK INFORMATION: Number: 8 Description: Unit 8 - Pipeline heater (PH-3), Nat. Gas Fired, 10.75 MMbtu/hr

Stack Height(ft): 0
Stack Diameter(ft): 0
Exit Gas Temperature(F): 0
Gas Flow Rate(ACFM): 0
Exit Gas Velocity(ft/sec): 0
Stack Type: F
Plume Height(ft): 10
Permitted Equipment: Y

UTM Zone: 18
UTM Vertical(KM): 4216.6
UTM Horizontal(KM): 279.55
GEP Stack Height: 0
GEP Building Height: 0
GEP Building Length: 0
GEP Bulding Width: 0
Rough Terrain: N
Elevation (ft above MSL): 0

Stack Emissions

Pollutant	Emissions Value (tpy)	Allowable Value	Units
CO	0.5787600000		
FORM	0.0005512000		
NO2	0.9646000000		
PB	0.0000034450		
PM	0.0523640000		
PM 10	0.0523640000		
PM 2.5	0.0523640000		
SO2	0.0041340000		
VOC	0.0192920000		

POINT INFORMATION: Number: 8 Description: Unit 8 - Pipeline Heater (PH-3), Nat. Gas Fired, 10.75 MMbtu/hr

Design Capacity & Units: 10.75 MILLION BTUS Per HOUR

State Sensitive: N
Permitted Equipment: N
Space Heat (%): 0
Air Program Sub Part

% Throughput: DEC-FEB: 2 MAR-MAY: 13 JUN-AUG: 53 SEP-NOV: 32
Operating Schedule: Hours/Day: 24 Days/Week: 7 Hours/Year: 8760

Point Emissions

Pollutant	Emissions Value (tpy)	Allowable Value	Units
CO	0.5787600000		
FORM	0.0005512000		
NO2	0.9646000000		
PB	0.0000034450		
PM	0.0523640000		
PM 10	0.0523640000		
PM 2.5	0.0523640000		
SO2	0.0041340000		
VOC	0.0192920000		

SEGMENT INFORMATION: Number: 1 Description: Pipeline Heater, Nat. Gas Fired

Source Classification Code: 39990003
Actual Annual Throughput: 13.78
Max. Hourly Operation Rate: 0
State Sensitive: N
Permitted Equipment: N
Insignificant Activity: N
Pollution Prevention: N

SCC Description: Natural Gas: Process Heaters
SCC Units: Million Cubic Feet Burned
Trace%: 0 Ash%: 0 Sulfur%: .001
Heat Content (MMBTU): 1025
Throughput Limit:
Throughput Unit:

Pollution Prevention Comments:
Segment Comments:

Segment Emissions

Pollutant	Method	Factor	A/S/T	Primary Control	Secondary Control	Overall Efficiency %	Emissions Value (tpy)	Allowable Value	Units
PB	Supplied factor (auto calc)	0.0005000000					0.00000344		
AP-42, Table 1.4-2, 7/98									
FORM	Supplied factor (auto calc)	0.0800000000					0.00055120		
SO2	Federal factor (auto calc)	0.6000000000					0.00413400		
VOC	Federal factor (auto calc)	2.8000000000					0.01929200		
AP-42, Table 1.4-2, 7/98									
PM	Supplied factor (auto calc)	7.6000000000					0.05236400		
Assume all PM is PM10									
PM 10	Supplied factor (auto calc)	7.6000000000					0.05236400		
AP-42, Table 1.4-2, 7/98									
PM 2.5	Supplied factor (auto calc)	7.6000000000					0.05236400		
CO	Supplied factor (auto calc)	84.0000000000					0.57876000		
AP-42, Table 1.4-1, 7/98									
NO2	Federal factor (auto calc)	140.0000000000					0.96460000		
AP-42, Table 1.4-1, 7/98									

STACK INFORMATION: Number: 9 Description: Unit 9 - Pipeline heater (PH-4), Nat. Gas Fired, 4.2 MMbtu/hr

Commonwealth of Virginia
Department of Environmental Quality
Consolidated Plant Emissions Report

Stack Height(ft):	0	UTM Zone:	18
Stack Diameter(ft):	0	UTM Vertical(KM):	4216.6
Exit Gas Temperature(F):	0	UTM Horizontal(KM):	279.55
Gas Flow Rate(ACFM):	0	GEP Stack Height:	0
Exit Gas Velocity(ft/sec):	0	GEP Building Height:	0
Stack Type:	F	GEP Building Length:	0
Plume Height(ft):	10	GEP Bulding Width:	0
Permitted Equipment:	Y	Rough Terrain:	N
		Elevation (ft above MSL):	0

Stack Emissions

Pollutant	Emissions Value (tpy)	Allowable Value	Units
CO	0.1969800000		
FORM	0.0001876000		
NO2	0.3283000000		
PB	0.0000011725		
PM	0.0178220000		
PM 10	0.0178220000		
PM 2.5	0.0178220000		
SO2	0.0014070000		
VOC	0.0065660000		

POINT INFORMATION: Number: 9 Description: Unit 9 - Pipeline Heater (PH-4), Nat. Gas Fired, 4.2 MMbtu/hr

Design Capacity & Units: 4.2 MILLION BTUS Per HOUR

State Sensitive: N
Permitted Equipment: N
Space Heat (%): 0
Air Program: Sub Part

% Throughput: DEC-FEB: 2 MAR-MAY: 13 JUN-AUG: 53 SEP-NOV: 32
Operating Schedule: Hours/Day: 24 Days/Week: 7 Hours/Year: 8760

Point Emissions

Pollutant	Emissions Value (tpy)	Allowable Value	Units
CO	0.1969800000		
FORM	0.0001876000		
NO2	0.3283000000		
PB	0.0000011725		
PM	0.0178220000		
PM 10	0.0178220000		
PM 2.5	0.0178220000		
SO2	0.0014070000		
VOC	0.0065660000		

SEGMENT INFORMATION: Number: 1 Description: Pipeline Heater, Nat. Gas Fired

Source Classification Code:	39990003	SCC Description:	Natural Gas: Process Heaters
Actual Annual Throughput:	4.69	SCC Units:	Million Cubic Feet Burned
Max. Hourly Operation Rate:	0	Trace%:	0 Ash%: 0 Sulfur%: .001
State Sensitive:	N	Heat Content (MMBTU):	1023
Permitted Equipment:	N		
Insignificant Activity:	N	Throughput Limit:	
Pollution Prevention:	N	Throughput Unit:	

Pollution Prevention Comments:

Segment Comments:

Segment Emissions

Pollutant	Method	Factor	A/S/T	Primary Control	Secondary Control	Overall Efficiency %	Emissions Value (tpy)	Allowable Value	Units
PB	Supplied factor (auto calc)	0.0005000000					0.00000117		
AP-42, Table 1.4-2, 7/98									
FORM	Supplied factor (auto calc)	0.0800000000					0.00018760		
SO2	Federal factor (auto calc)	0.6000000000					0.00140700		
VOC	Federal factor (auto calc)	2.8000000000					0.00656600		
AP-42, Table 1.4-2, 7/98									
PM	Supplied factor (auto calc)	7.6000000000					0.01782200		
Assume all PM is PM10									
PM 10	Supplied factor (auto calc)	7.6000000000					0.01782200		
AP-42, Table 1.4-2, 7/98									
PM 2.5	Supplied factor (auto calc)	7.6000000000					0.01782200		
CO	Supplied factor (auto calc)	84.0000000000					0.19698000		
AP-42, Table 1.4-1, 7/98									
NO2	Federal factor (auto calc)	140.0000000000					0.32830000		
AP-42, Table 1.4-1, 7/98									

Attachment B

Minor NSR Permit dated August 18, 2015

COMMONWEALTH of VIRGINIA

DEPARTMENT OF ENVIRONMENTAL QUALITY
NORTHERN REGIONAL OFFICE
13901 Crown Court, Woodbridge, Virginia 22193
(703) 583-3800 Fax (703) 583-3821
www.deq.virginia.gov

Molly Joseph Ward
Secretary of Natural Resources

David K. Paylor
Director

Thomas A. Faha
Regional Director

August 18, 2015

Mr. Scott Lawton
Director - Electric Environmental Business Support
Dominion Resources Services, Inc.
5000 Dominion Boulevard
Glen Allen, VA 23060

Location: Caroline County
Registration No.: 40960

Dear Mr. Lawton:

Attached is a permit to construct and operate an electric power generation facility (Ladysmith Combustion Turbine Station), including three new emergency diesel engine generators, in accordance with the provisions of the Virginia State Air Pollution Control Board Regulations for the Control and Abatement of Air Pollution. This permit supersedes your permit dated September 29, 2011.

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

The proposed engine-generator sets may be subject to 40 CFR 63, Maximum Achievable Control Technology (MACT), Subpart ZZZZ and 40 CFR 60, New Source Performance Standard (NSPS), Subpart IIII. In summary, the units may be required to comply with certain federal emission standards and operating limitations. The Department of Environmental Quality (DEQ) advises you to review the referenced MACT and NSPS to ensure compliance with applicable emission and operational limitations. As the owner/operator you may be also responsible for any monitoring, notification, reporting and recordkeeping requirements of the MACT and NSPS. Notifications shall be sent to EPA, Region III.

To review any federal rules referenced in the above paragraph or in the attached permit, the U.S. Government Publishing Office maintains the text of these rules at www.ecfr.gov, Title 40, Part 60 and/or 63.

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

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

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

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

If you have any questions concerning this permit, please contact John McKie at (703) 583-3831.

Sincerely,

James B. LaFratta

James B. LaFratta
Regional Air Permit Manager

JBL/JRM/40960_Permit_8-18-2015_mNSR.docx

Attachments: Permit
Source Testing Report Format

CC: Regional Air Permit Manager (electronic copy)
OAPP (electronic copy)
Mary Cate Opila, Office of Permits and Air Toxics, EPA Region III (electronic copy)

COMMONWEALTH of VIRGINIA

DEPARTMENT OF ENVIRONMENTAL QUALITY

NORTHERN REGIONAL OFFICE
13901 Crown Court, Woodbridge, Virginia 22193
(703) 583-3800 Fax (703) 583-3821
www.deq.virginia.gov

Molly Joseph Ward
Secretary of Natural Resources

David K. Paylor
Director

Thomas A. Faha
Regional Director

STATIONARY SOURCE PERMIT TO CONSTRUCT AND OPERATE
This permit includes designated equipment subject to
New Source Performance Standards (NSPS)
This permit includes designated equipment subject to
National Emission Standards for Hazardous Air Pollutants for Source Categories

<u>This permit supersedes your permit dated September 29, 2011.</u>

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

Virginia Electric and Power Company
5000 Dominion Boulevard
Glen Allen, VA 23060
Registration No.: 40960

is authorized to construct and operate:

five simple-cycle combustion turbines, three diesel engine generator sets, and associated auxiliary equipment composing the Ladysmith Combustion Turbine Station

located at:

8063 Cedon Road
Woodford, Virginia 22580

in accordance with the Conditions of this permit.

Approved on August 18, 2015

James B. LaFratta
for Thomas A. Faha
Regional Director

Permit consists of 38 pages.
Permit Conditions 1 to 65.

INTRODUCTION

This permit approval is based on the permit applications dated May 27, 2015 and November 17, 2014 with additional information dated: January 9 (e-mail), 12, and 13 (e-mail) 2015; May 27 (e-mail), 2015; August 3, and 11, 2015; and, on previous applications dated: November 9, 2010 and October 31, 2007; with additional information dated November 16, 2007, January 7 & 9, 2008, and February 6 & 21, 2008. Additional correspondence regarding this facility includes permit applications dated November 17, 2006, August 14, 1998, including amendment sheets dated January 14, 1999, February 22, 1999, March 24, 1999, November 9, 1999 and May 2, 2000. Any changes in the permit application specifications or any existing facilities which alter the impact of the facility on air quality may require a permit. Failure to obtain such a permit prior to construction may result in enforcement action. In addition, this facility may be subject to additional applicable requirements not listed in this permit.

Words or terms used in this permit shall have meanings as provided in 9 VAC 5-10-20 and 9 VAC 5-80-1110 of the State Air Pollution Control Board Regulations for the Control and Abatement of Air Pollution. The regulatory reference or authority for each condition is listed in parentheses () after each condition.

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

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

Equipment List – Equipment at this facility consists of:

Equipment to be Constructed:			
Reference No.	**Equipment Description**	**Rated Capacity**	**Federal Requirements**
EDG1 EDG2 EDG3	Each is a Caterpillar C175-16 diesel engine-powered generator set	Engine output = 4,423 bhp each; Electrical output = 3,000 kW each	40 CFR Part 60, Subpart IIII* 40 CFR Part 63, Subpart ZZZZ*

*These particular federal requirements are enforced through DEQ-issued federal operating permits, but not through the new source review program of which this permit is part.

Equipment permitted prior to the date of this permit:				
Reference No.	**Equipment Description**	**Rated Capacity**	**Federal Requirements**	**Original Permit Date**
Units 1 & 2	Both are GE Model PG7241 (FA) simple cycle, dual fuel, combustion turbines (CT)	When operated at 100% base load at an ambient temperature of 59° F and a pressure of 29.92 inches of Hg, 1,761.0 MMBtu/hr on natural gas, each; or 1,910.0 MMBtu/hr on No.2 distillate fuel oil, each.	NSPS GG	07/31/00
Units 3 & 4	Both are GE Model PG7241 (FA) simple cycle, dual fuel, combustion turbines (CT)	When operated at 100% base load at an ambient temperature of 59° F and a pressure of 29.92 inches of Hg, 1,761.0 MMBtu/hr on natural gas, each; or 1,910.0 MMBtu/hr on No.2 distillate fuel oil, each.	NSPS KKKK	07/06/07
Units 5	GE Model PG7241 (FA) simple cycle, dual fuel, combustion turbines (CT)	When operated at 100% base load at an ambient temperature of 59° F and a pressure of 29.92 inches of Hg, 1,761.0 MMBtu/hr on natural gas, each; or 1,910.0 MMBtu/hr on No.2 distillate fuel oil, each.	NSPS KKKK	07/01/08
PH3	One – natural gas fuel pipeline heater	10.75 MMBtu/hr	NSPS Dc	07/01/08
PH4	One – natural gas fuel pipeline heater	4.2 MMBtu/hr		07/01/08
T1 & T2	Two – fixed roof storage tanks for No. 2 distillate fuel oil	2,700,000 gallons (nominal capacity), each.		07/31/00

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

1. **Emission Controls** – CT's (Ref. Nos. Units 1 – 5)
   Nitrogen oxides (NO_X) emissions from each CT shall be controlled by the utilization of a dry low NO_X combustor when firing natural gas, or water injection when firing No.2 distillate fuel oil. The CT's shall be provided with adequate access for inspection.
   (9 VAC 5-80-1180 and 9 VAC 5-50-260)

2. **Emission Controls** – (Ref. Nos. PH3 and PH4)
   Nitrogen oxides (NO_X) emissions from each natural gas pipeline heater shall be controlled by the use of good combustion operating practices. The pipeline heaters shall be provided with adequate access for inspection.
   (9 VAC 5-80-1180 and 9 VAC 5-50-260)

3. **Emission Controls** – (Ref. Nos. EDG1, EDG2 and EDG3)
   Nitrogen oxides (NO_X) emissions from the engine-generator sets shall be controlled by turbocharged engine and aftercooler. The permittee shall maintain documentation that demonstrates that turbocharging and aftercooling equipment has been installed on the engine-generator sets.
   (9 VAC 5-80-1180 and 9 VAC 5-50-260)

4. **Emission Controls** – (Ref. Nos. Units 1 – 5, PH3, and PH4)
   Sulfur dioxide (SO_2) emissions from each CT and from each natural gas pipeline heater shall be controlled by the use of low sulfur fuels.
   (9 VAC 5-80-1180 and 9 VAC 5-50-260)

5. **Emission Controls** – (Ref. Nos. EDG1, EDG2 and EDG3)
   Sulfur dioxide (SO_2) emissions from the engine-generator sets shall be controlled by the use of ultra low sulfur diesel (ULSD) fuel.
   (9 VAC 5-80-1180 and 9 VAC 5-50-260)

6. **Emission Controls** – (Ref. Nos. Units 1 – 5, PH3, and PH4)
   Particulate matter (PM-10) emissions from each CT and from each natural gas pipeline heater shall be controlled by the use of clean burning fuels and good combustion operating practices.
   (9 VAC 5-80-1180 and 9 VAC 5-50-260)

7. **Emission Controls** – (Ref. Nos. Units 1 – 5, PH3, and PH4)
   Volatile organic compounds (VOC) and carbon monoxide (CO) emissions from each CT and from each natural gas pipeline heater shall be controlled by the use of good combustion operating practices.
   (9 VAC 5-80-1180 and 9 VAC 5-50-260)

8. **Emission Controls** - (Ref. Nos. EDG1, EDG2 and EDG3)
   Visible emissions shall be controlled by the use of good operating practices and performing appropriate maintenance in accordance with the manufacturer recommendations. In addition, the permittee may only change those settings that are permitted by the manufacturer and does not increase air emissions.
   (9 VAC 5-80-1180)

9. **Monitoring Devices** – (Ref. Nos. EDG1, EDG2 and EDG3)
   Each engine-generator set shall be equipped with a non-resettable hour metering device to

monitor the operating hours. The non-resettable hour meter used to continuously measure the hours of operation for each engine-generator set shall be observed by the owner with a frequency of not less than once each day the engine-generator set is operated to ensure that the hour meter is functioning as intended. The owner shall keep a log of these observations. Each monitoring device shall be installed, maintained, calibrated (as appropriate) and operated in accordance with approved procedures which shall include, as a minimum, the manufacturer's written requirements or recommendations. Each monitoring device shall be provided with adequate access for inspection and shall be in operation when the engine-generator sets are operating.
(9 VAC 5-80-1180 D)

OPERATING LIMITATIONS

10. **Operation of the Engine-Generator Sets -** (Ref. Nos. EDG1, EDG2 and EDG3)
The permittee shall operate and maintain each engine-generator set according to the manufacturer's written instructions or procedures developed by the permittee that are approved by the engine manufacturer. In addition, the permittee may only change those settings that are permitted by the manufacturer and does not increase air emissions.
(9 VAC 5-80-1180)

11. **Operating Hours** – (Ref. Nos. EDG1, EDG2 and EDG3)
Each engine-generator set shall not operate more than 500 hours per year, calculated monthly as the sum of each consecutive 12 month period. Compliance for the consecutive 12 month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months.
(9 VAC 5-80-1180)

12. **Emergency Power Generation** – (Ref. Nos. EDG1, EDG2 and EDG3)
The engine-generator sets shall only be operated in the following modes:

    a. When emergency power is required to start up the CT's in the event of failure of the electrical grid.

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

        i. A failure of the electrical grid;

        ii. On-site disaster or equipment failure; or

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

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

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

ii. Capacity deficiency or capacity excess conditions;

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

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

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

d. For periodic maintenance, testing, and operational training.

(9 VAC 5-80-1180)

13. **Fuel** – (Ref. Nos. Units 1 – 5)
The approved fuels for the combustion turbines are pipeline quality natural gas (primary fuel) and No. 2 distillate fuel oil (back-up fuel).

Distillate oil is defined as fuel oil that meets the specifications for Fuel Oil Numbers 1 or 2 under the American Society for Testing and Materials, ASTM D396, "Standard Specification for Fuel Oils," or other approved ASTM methods, incorporated in 40 CFR 60 by reference. A change in fuel may require a permit to modify and operate. Records of all fuel supplier certifications shall be available for inspection and shall be current for the most recent five years.
(9 VAC 5-80-1180)

14. **Fuel** – (Ref. Nos. PH3 and PH4)
The approved fuel for the pipeline heaters is pipeline quality natural gas.
(9 VAC 5-80-1180)

15. **Fuel** - (Ref. Nos. EDG1, EDG2 and EDG3)
The approved fuel for the engine-generator sets is ultra low sulfur diesel (ULSD) fuel that meets the specifications below:

a. ASTM D975 specification for S15 diesel fuel oil with a maximum sulfur content per shipment of 0.0015%; or,

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

Exceedance of these specifications may be considered credible evidence of an exceedance of emission limits. A change in the fuel type or the fuel sulfur content may require a new or amended permit.
(9 VAC 5-80-1180 and 9 VAC 5-50-260)

16. **Natural Gas Fuel Specifications** – (Ref. Nos. Unit 1 and Unit 2)
The maximum sulfur content of the natural gas to be burned in the CT's shall not exceed 20 grains per 100 dry standard cubic feet. The annual average sulfur content of the natural gas to be burned in the CT's shall not exceed 0.5 grains per 100 dry standard cubic feet per year, calculated monthly as the average of each consecutive twelve-month period. Compliance for the consecutive twelve-month period shall be demonstrated monthly by averaging the total for the most recently completed calendar month to the individual monthly totals for the preceding eleven months.
(9 VAC 5-80-1180 and 9 VAC 5-50-260)

17. **Natural Gas Fuel Specifications** – (Ref. Nos. Units 3 – 5, PH3, and PH4)
The maximum sulfur content of the natural gas to be burned in the CT's and the pipeline heaters shall not exceed 0.060 lb SO_2/MMBtu heat input.
(9 VAC 5-80-1180 and 9 VAC 5-50-260)

18. **No. 2 Distillate Fuel Oil Specifications** – (Ref. Nos. Unit 1 and Unit 2)
The maximum sulfur content of the No. 2 distillate fuel oil to be burned in the CT's shall not exceed 0.05% by weight per oil shipment/transfer (shipment/transfer as defined in Appendix A of this permit).
(9 VAC 5-80-1180 and 9 VAC 5-50-260)

19. **No. 2 Distillate Fuel Oil Specifications** – (Ref. Nos. Units 3 – 5)
The maximum sulfur content of the No. 2 distillate fuel oil to be burned in the CT's shall not exceed 0.060 lb SO_2/MMBtu heat input.
(9 VAC 5-80-1180 and 9 VAC 5-50-260)

20. **Fuel Certification** – (Ref. Nos. Units 1 – 5, EDG1, EDG2, and EDG3)
The permittee must use one of the following combination of sources (A, B, and D; or, A, C, and D below) of information to demonstrate compliance with Conditions 13, 15, 16, 17, 18 and 19, in addition to demonstrating compliance through the continuing compliance requirements at Condition 48 and record keeping requirements at Conditions 50 and 51:

    A. No. 2 Distillate Fuel Oil (Ref. Nos. Unit 1 and Unit 2)
    The permittee shall obtain a certification from the fuel supplier and/or the fuel oil delivery company with each shipment of No. 2 distillate fuel oil. Each fuel supplier certification shall include the following:

        i. The name of the fuel supplier/fuel delivery company;

        ii. The date on which the No. 2 distillate fuel oil was received;

        iii. The quantity of No. 2 distillate fuel oil delivered in the shipment;

        iv. A statement that the No. 2 distillate fuel oil complies with the American Society for Testing and Materials specifications (ASTM D396) for Numbers 1 and 2 fuel oil or other approved ASTM method incorporated in 40 CFR 60 by reference; and,

v. The actual sulfur content of the No. 2 distillate fuel oil or, upon last delivery of the No. 2 distillate fuel oil, the permittee shall collect an oil sample from the on-site fuel oil storage tank for use in determining the fuel oil sulfur content.

AND

B. Fuel Oil and Natural Gas (Ref. Nos. Units 3 – 5)

i. The fuel characteristic in a current, valid purchase contract, tariff sheet or transportation contract for the natural gas, specifying that the maximum total sulfur content for the natural gas is 20 grains of sulfur or less per 100 standard cubic feet.

ii. For the No. 2 distillate fuel oil, a valid purchase contract, tariff sheet or transportation contract which shows the fuel oil being burned contains 500 parts per million (0.05% by weight) or less sulfur.

OR

C. Fuel Oil and Natural Gas (Ref. Nos. Unit 3 – 5)

Representative fuel sampling data, which shows that the sulfur content of the fuels does not exceed 0.060 lb SO_2/MMBtu heat input.

AND

D. Diesel Fuel (Ref Nos. EDG1, EDG2, and EDG3)
To determine compliance with Condition 15 the permittee shall obtain a certification from the fuel supplier with each shipment of diesel fuel. Each fuel supplier certification shall include the following:

i. The name of the fuel supplier;

ii. The date on which the diesel fuel was received;

iii. The quantity of diesel fuel delivered in the shipment;

iv. A statement that the diesel fuel complies with the American Society for Testing and Materials specifications (ASTM D975) for S15 diesel fuel oil; or the permittee shall obtain approval from the Regional Air Compliance Manager of the DEQ's NRO if other documentation will be used to certify the diesel fuel oil type.

(9 VAC 5-80-1180 and 9 VAC 5-170-160)

21. **Fuel Tanks** – (Ref. Nos. T1 and T2)
The two 2,700,000 gallon fixed-roof storage tanks shall be used to store only No. 2 distillate fuel oil with a sulfur content not to exceed 0.05% by weight.
(9 VAC 5-80-1180)

22. **Requirements by Reference** – (Ref. Nos. Unit 1 and Unit 2)
Except where this permit is more restrictive than the applicable requirement, the CT's as

described in Condition 1, shall be operated in compliance with the requirements of 40 CFR 60, Subpart GG (Standards of Performance for Stationary Gas Turbines).
(9 VAC 5-80-1180, 9 VAC 5-50-400 and 9 VAC 5-50-410)

23. **Requirements by Reference** – (Ref. Nos. Units 3 – 5)
Except where this permit is more restrictive than the applicable requirement, the CT's as described in Condition 1, shall be operated in compliance with the requirements of 40 CFR 60, Subpart KKKK (Standards of Performance for Stationary Combustion Turbines)
(9 VAC 5-80-1180, 9 VAC 5-50-400 and 9 VAC 5-50-410)

24. **Requirements by Reference** – (Ref. Nos. PH3 and PH4)
Except where this permit is more restrictive than the applicable requirement, the pipeline heater , as described in Condition 1, shall be operated in compliance with the requirements of 40 CFR 60, Subpart Dc (Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units)
(9 VAC 5-80-1180, 9 VAC 5-50-400 and 9 VAC 5-50-410)

25. **Alternate Operating Scenario** – Re-tuning (Ref. Nos. Units 1 – 5)

A. Alternate 1 while operating on Natural Gas – (Units 1 – 5) – Re-tuning of the CT's shall be conducted in accordance with those procedures outlined in Appendix C of this permit.

B. Alternate 2 while operating on No. 2 Distillate Oil (Ref. Nos. Units 1 – 5) – Re-tuning of the CT's shall be conducted in accordance with those procedures outlined in Appendix C of this permit.

Excess emissions resulting from the re-tuning of the combustion turbines shall be permitted provided that:

C. Best operational practices are adhered to and the duration of excess emissions shall be minimized but in no case exceed twelve hours per combustion turbine (CT) re-tuning event in any twenty-four hour period. The operator may request additional hours from the DEQ

D. During each CT's (Ref. Nos. Unit 1 and Unit 2) re-tuning event, NO_X emission concentrations, based on a four hour average, shall not exceed the NO_X standards of the New Source Performance Standards (NSPS) 40 CFR 60 Subpart GG - Standards of Performance for Stationary Gas Turbines (60.330 et seq.).

E. During each CT's Ref. Nos. (Units 3 – 5) re-tuning event, NO_X emission concentrations, based on a four hour average, shall not exceed the NO_X standards of the New Source Performance Standards (NSPS) 40 CFR 60 Subpart KKKK - Standards of Performance for Stationary Combustion Turbines (60.4300 et seq.)

F. Other Excess Emissions – Other excess emissions resulting from the re-tuning of each combustion turbine shall be permitted provided that the procedures specified in Appendix C are followed.

G. The permittee shall notify the Regional Air Compliance Manager of the DEQs Northern Regional Office (NRO) at:

Regional Air Compliance Manager
Department of Environmental Quality
13901 Crown Court
Woodbridge, Virginia 22193

no less than twenty-four hours prior to each CT's re-tuning event. The notification shall include, but is not limited to, the following information.

i. Identification of the specific CT to be re-tuned.

ii. Reason for the re-tuning event.

iii. Measures that will be taken to minimize the length of the re-tuning event.

H. The permittee shall furnish a written report to the Regional Air Compliance Manager of the DEQ's NRO at the above address of all pertinent facts concerning the re-tuning event, as soon as practicable but not later than fourteen business days after the re-tuning event. The notification shall include, but is not limited to, the following information.

i. Identification of the CT that was re-tuned.

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

I. NO_X emissions during each CT's re-tuning event shall be recorded and included in the associated quarterly reports and in the total annual emissions as required in Conditions 32, 33, and 34.

J. The re-tuning event for each CT shall be identified on the Data Acquisition Report.

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

26. **Alternate Operating Scenario** – Fuel Type Transfer (Ref. Nos. Units 1 – 5)

Fuel transfer is limited to the following:

A. Event 1 – Automatic or Operator Initiated Fuel Transfer from Pipeline Natural Gas to No.2 Distillate Fuel Oil: The period will begin when gas usage is first reduced for the purpose of transferring to No.2 distillate fuel oil and will end when No.2 distillate fuel oil consumption and water injection have stabilized.

B. Event 2 – Operator Initiated Fuel Transfer from No.2 Distillate Fuel Oil to Pipeline Natural Gas: The period will begin when the turbine's work load is reduced for the purpose of transferring to natural gas and will end when No.2 distillate fuel oil usage ceases and the turbine is re-stabilized in Mode 6 for Dry Low NO_X Burners.

C. Excess NO_X Emissions – Excess NO_X emissions from each combustion turbine shall be limited to no more than three one-hour averaging periods for any fuel type transfer event, unless specifically authorized by DEQ for longer duration prior to the event, however, in no case shall the NO_X emissions exceed the limits specified in 40 CFR 60, Subpart GG for Ref. Nos. Unit 1 and Unit 2 and 40 CFR 60, Subpart KKKK for Ref. Nos. Unit 3, Unit 4, and Unit 5. For each fuel type transfer event, the permittee shall:

i. Operate all equipment in a manner consistent with air pollution control practices for minimizing emissions.

ii. Within thirty days of any changes in the procedures outlined in Appendix B of this permit, notify and provide a general description of the new procedures to be followed during periods of fuel type transfer to ensure that the best operational practices to minimize emissions will be adhered to and the duration of excess emissions will be minimized.

iii. The description shall be submitted to the Regional Air Compliance Manager of the DEQ's NRO at the address specified in Condition 25.

iv. Excess emissions during the fuel type transfer will be recorded and included in the quarterly Excess Emission Report. The CEM data will be "flagged" to indicate that fuel type transfer took place.

D. Other Excess Emissions – Other excess emissions resulting from the fuel type transfer for each combustion turbine shall be permitted provided that the procedures specified in Appendix B are followed.

All correspondence concerning this permit should be submitted to the address listed in Condition 25.
(9 VAC 5-20-180 J and 9 VAC 5-50-20 E)

27. **Alternate Operating Scenario** – Low Load Emergency (LLE) Mode (Ref. Nos. Units 1 – 5) During electric grid restoration, the combustion turbines (CT's) may operate for an extended period of time at a low startup load. This scenario of operation is known as low load emergency (LLE) mode. LLE mode may be tested once each calendar year. A successful test is considered to be a sustained generation from the CT's while operating in LLE mode. The turbines may be operated in LLE mode during a Pennsylvania-New Jersey-Maryland Interconnection, LLC (PJM) Independent System Operator's (ISO) declared emergency and during the once per calendar year LLE mode test.
(9 VAC 5-80-1180, Virginia Code 10.1-1307.02, and Virginia Code 10.1-1307.3.A.5)

EMISSION LIMITS

28. **Short-term Emission Limits** – Natural Gas (Ref. Nos. Unit 1 and Unit 2)
Short-term emission limits from the operation of each CT while firing on natural gas shall not exceed the limits specified below (except during start-up and shut-down (as defined below), fuel type transfer, re-tuning, and LLE mode events):

PM-10	18 lbs/hr
Carbon Monoxide	9 ppmvd @ 15% O_2 (3-hour average)
Nitrogen Oxides (as NO_2)	9 ppmvd @ 15% O_2 (1-hour average)

A "start-up" is defined as the period commencing with ignition of the unit and consisting of two (2) hours of continuous emission monitoring system (CEMS) data.

A "shut-down" is defined as the period comprising the final two (2) hours of CEMS data prior to the time when no fuel is being combusted.
(9 VAC 5-80-1180 and 9 VAC 5-50-260)

29. **Short-term Emission Limits** – Natural Gas (Ref. Nos. Units 3 – 5)
Short-term emission limits from the operation of each CT while firing on natural gas shall not exceed the limits specified below (except during start-up, shut-down (except during start-up and shut-down (as defined in Condition 28), fuel type transfer, re-tuning, and LLE mode events):

PM-10	18 lbs/hr
Carbon Monoxide	9 ppmvd @ 15% O_2 (3-hour average)
Nitrogen Oxides (as NO_2)	9 ppmvd @ 15% O_2 (1-hour average)
Sulfur Dioxide (SO_2)	0.060 lb/MMBtu

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

30. **Short-term Emission Limits** – No. 2 Distillate Fuel Oil (Ref. Nos. Unit 1 and Unit 2)
Short-term emission limits from the operation of each CT while firing on No. 2 distillate fuel oil shall not exceed the limits specified below (except during start-up and shut-down (as defined in Condition 28), fuel type transfer, re-tuning, and LLE mode events):

PM-10	34 lbs/hr
Carbon Monoxide	30 ppmvd @ 15% O_2 (3-hour average)
Nitrogen Oxides (as NO_2)	42 ppmvd @ 15% O_2 (1-hour average)*

*See Condition 34.

31. **Short-term Emission Limits –** No. 2 Distillate Fuel Oil (Ref. Nos. Units 3 – 5)
Short-term emission limits from the operation of each CT while firing on No. 2 distillate fuel oil shall not exceed the limits specified below (except during start-up and shut-down (as defined in Condition 28), fuel type transfer, re-tuning, and LLE mode events):

PM-10	34 lbs/hr
Carbon Monoxide	30 ppmvd @ 15% O_2 (3-hour average)
Nitrogen Oxides (as NO_2)	42 ppmvd @ 15% O_2 (1-hour average)
Sulfur Dioxide (SO_2)	0.060 lb/MMBtu

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

32. **Annual Emission Limits** – (Ref. Nos. Units 1 – 5)

A. Total emissions from the combined operation of the five CT's shall not exceed the limits specified below:

PM-10	73.8 tons/year
Carbon Monoxide	119 tons/year
Nitrogen Oxides (as NO_2)	237 tons/year
Sulfur Dioxide (SO_2)	74.4 tons/year
Volatile Organic Compounds (VOC)	11.5 tons/year

B. The NO_X emission rates shall be calculated daily as the sum of each consecutive 365-day period. Compliance determination with the annual NO_X limit shall be determined using the NO_X Mass Emission Provisions of 40 CFR Part 75, Subpart H, with the exception of data substitution as described in Condition 41.A or 41.B of this permit.

C. SO_2, CO, PM/PM10 and VOCs shall be calculated monthly as the sum of each consecutive twelve-month period. Compliance for the consecutive twelve-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 eleven months.

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

33. **Annual Emission Limits** - Facility wide

A. Total emissions from the combined operation of all the emissions sources at the Ladysmith Generation Facility (as listed in the Equipment List at the Introduction) shall not exceed the limits specified below:

PM-10	74.3 tons/year
Carbon Monoxide	124.6 tons/year
Nitrogen Oxides	248.2 tons/year

(as NO_2)	
Sulfur Dioxide (SO_2)	74.4 tons/year
Volatile Organic Compounds (VOC)	11.8 tons/year

B. The total annual emissions from facility shall be calculated monthly as the sum of each consecutive twelve-month period. Compliance for the consecutive twelve-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 eleven months.

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

34. **Emission Limits** – NO_X (Ref. Nos. Units 1 and Unit 2)
NO_X emissions (as NO_2) from each CT when firing No. 2 distillate fuel oil shall not exceed 42 ppmvd at 15% O_2 on a one hour average basis (as measured by CEMS), when fuel bound nitrogen (FBN) values are less than or equal to 0.015%. If the source wishes to account for the FBN allowance as provided in NSPS 40 CFR 60, Subpart GG, for FBN values up to 0.05% (the maximum FBN allowed), the adjusted standard shall be determined, recorded and maintained upon each new fuel delivery by the following formula:

Standard = (0.04 * N) + 0.0042 where:

Standard = allowable NO_X emissions (percent by volume at 15% O_2 and on a dry basis)

N = the nitrogen content of the fuel oil (percent by weight)

Note: 0.0042% = 42 ppm

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

35. **Emission Limit** – Visible emissions (Ref. Nos. Units 1 – 5)
Visible emissions from each CT exhaust stack shall not exceed ten percent opacity except during one six-minute period in any one hour in which visible emissions shall not exceed twenty percent opacity as determined by the EPA Method 9 (reference 40 CFR 60, Appendix A). This condition applies at all times except during: start-up and shut-down (as defined in Condition 28); fuel type transfer, re-tuning, and LLE mode events; and, malfunction.
(9 VAC 5-80-1180 and 9 VAC 5-50-260)

36. **Emission Limits - (Ref. Nos. EDG1, EDG2 and EDG3)**
Emissions from the operation of the engine-generator sets shall not exceed the limits specified below:

	Each Genset	All Three Gensets Combined
Nitrogen Oxides (as NO_2)	50.7 lbs/hr *	38.0 tons/yr
Carbon Monoxide	6.2 lbs/hr	4.7 tons/yr
Volatile Organic Compounds (VOC)	1.0 lbs/hr	0.8 tons/yr

*This rate is less than 6.0 g/hp-hr at maximum load.

These emissions are derived from the estimated overall emission contribution from operating limits. Exceedance of the operating limits may be considered credible evidence of the exceedance of emission limits. Compliance with these emission limits may be determined as stated in Conditions 45, 46 and 51.
(9 VAC 5-80-1180)

37. **Emission Limit – Visible emissions (Ref. Nos. EDG1, EDG2 and EDG3)**
Visible emissions from each engine-generator set exhaust shall not exceed 10% opacity except during one 6-minute period in any one hour in which visible emissions shall not exceed 20% opacity as determined by EPA Method 9 (reference 40 CFR 60, Appendix A). This condition applies at all times except during startup, shutdown and malfunction.
(9 VAC 5-80-1180)

CONTINUOUS EMISSION MONITORING SYSTEMS (CEMS)

38. **NO_X CEMS** – Compliance Determination (Ref. Nos. Units 1 – 5)
At the discretion of the Board, the NO_X emission monitors required by this permit, the continuous monitoring data, and the quality assurance data shall be used to determine compliance with the NO_X emission limits and/or relevant emission standards. Each monitor is subject to such data capture requirements and/or quality assurance requirements as specified in this permit and as may be deemed appropriate by the Board.
(9 VAC 5-50-40 and 9 VAC 5-50-410)

39. **NO_X CEMS** – Operation (Ref. Nos. Units 1 – 5)

A. CEMS shall be installed, maintained and operated to measure and record the emissions of nitrogen oxides from each CT's exhaust stack. A diluent monitor (O_2 or CO_2) shall be co-located with each nitrogen oxide concentration monitor.

B. The CEMS shall be installed, maintained, calibrated and operated in accordance with the performance specifications and test procedures (as applicable) identified in 40 CFR 75, Appendices A and B. Upon request by the DEQ, the source shall conduct performance tests. A thirty day notification, prior to the demonstration of the CEMs performance shall be submitted to the Regional Air Compliance Manager of the DEQ's NRO (at the address listed in Condition 25). Two copies of the performance test evaluation reports (one hard copy and one electronic copy) shall be submitted to Regional Air Compliance Manager of the DEQ's NRO at the address listed in Condition 25.

C. The quality assurance of data generated by the CEMS shall be demonstrated by implementing or exceeding the minimum requirements for CEMS quality assurance as defined in 40 CFR 75, Appendix B. A NO_X CEMS quality control program which meets the requirements of 40 CFR 75 and 40 CFR 75, Appendix B, shall be implemented for all continuous monitoring systems. As per Part 75, Appendix B, no more than four successive calendar quarters plus the allowable grace period allowed in 40 CFR Part 75 will elapse without performing a NO_X and O_2 or CO_2 analyzer linearity check. As per Part 75, Appendix B, no more than eight successive calendar quarters plus the allowable grace period allowed in 40 CFR Part 75 shall elapse without performing a NO_X CEMS RATA.

(9 VAC 5-50-40, 9 VAC 5-50-50 and 9 VAC 5-50-410)

40. **NO_X CEMS** – Minimum Data Capture (Ref. Nos. Units 1 – 5)

The NO_X CEMS required by this permit shall meet a minimum data capture of 90% of each CT's operating hours, calculated monthly as the sum of each consecutive twelve-month period. Compliance for the consecutive twelve-month period shall be demonstrated monthly by adding the total available CEM operating hours for the most recently completed calendar month to the total available CEM operating hours for the preceding eleven months divided by the total unit operating hours for the most recently completed calendar month plus the total unit operating hours for the preceding eleven months multiplied by one hundred.
(9 VAC 5-50-40 and 9 VAC 5-50-410)

41. **NO_X CEMS** – Failure (Ref. Nos. Units 1 – 5)

In the event of a NO_X CEMS failure, the permittee must either:

A. Use the maximum allowable hourly NO_X emission rate (in ppm), for each hour of operation where CEMS data is not available. This data shall be included in the rolling 365-day emission summation; or

B. Provide data which demonstrates an accurate correlation between the water-to-fuel injection curve and actual emission rates. Upon approval of the DEQ, this curve can be used as surrogate CEM data for future emission calculations.

(9 VAC 5-50-40)

42. **NO_X CEMS** – Reports for CEMS (Ref. Nos. Units 1 – 5)
The permittee shall furnish one hard copy and one electronic copy (using the contact information referenced in Condition 25) to the Regional Air Compliance Manager of the DEQ's NRO, of excess emissions from any process monitored by a CEMS, on a quarterly basis, postmarked no later than the thirtieth day following the end of the calendar quarter. These reports shall include, but are not limited to the following information:

A. For each month in the quarter, report each hour in which a NO_X permit limit is exceeded. The report shall include for each excess emission of NO_X: start time, duration, equipment involved, actual NO_X emissions in ppmvd @ 15% O_2, and fuel type.

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

(9 VAC 5-50-50 and 9 VAC 5-170-160)

43. **Fuel Consumption** – Instrumentation/Backup Method (Ref. Nos. Units 1 – 5)
The permittee shall install and maintain instrumentation or have an available backup method

as approved by the DEQ, to indicate/determine and record the hourly fuel consumption (in scf/hour and gallons/hour) of each CT (when in operation). These records shall be kept on file at the facility for the most current five year period.
(9 VAC 5-50-40 and 9 VAC 5-50-410)

44. **Monitoring Opacity** – Visible Emission Observation (Ref. Nos. Units 1 – 5)

A. The permittee shall perform a visible emission observation (VEO) on each exhaust stack of CT once each day that the CT's are operated. The VEO shall be based on the techniques of an EPA Method 22 with a follow-up EPA Reference Method 9, should an observation indicate visible emissions for more than six consecutive minutes.

B. Each VEO shall be performed for a sufficient period of time to identify the presence or absence of visible emissions. If no visible emissions are observed, no action shall be required.

C. However, if visible emissions are observed, a visible emissions evaluation (VEE) shall be conducted using 40 CFR Part 60, Appendix A, Method 9 for a period of not less than 6-minutes and:

i. If the average opacity exceeds 20%, modifications and/or repairs to the CT shall be performed to correct the problem and the corrective measures shall be recorded;

ii. Following any corrective measures, a VEE in accordance with 40 CFR Part 60, Appendix A, Method 9, shall be performed for a period of at least 18 consecutive minutes to determine compliance with the opacity limits specified in this permit;

iii. The follow-up VEE, if required, shall be conducted by a currently certified Visible Emission Evaluator.

(9 VAC 5-80-110)

CONTINUING COMPLIANCE DETERMINATION

45. **Stack Tests** (Ref. Nos. Units 1 – 5, EDG1, EDG2, and EDG3)
Upon request by the DEQ, or in accordance with federal requirements, the permitted facility shall conduct additional performance tests to demonstrate compliance with the emission limits contained in this permit. The details of the tests shall be arranged with the Regional Air Compliance Manager of the DEQ's NRO.
(9 VAC 5-50-30 G and 9 VAC 5-80-1180)

46. **Emissions Testing** (Ref. Nos. EDG1, EDG2, and EDG3)
The facility shall be constructed so as to allow for emissions testing upon reasonable notice at any time, using appropriate methods. Sampling ports shall be provided when requested at the appropriate locations and safe sampling platforms and access shall be provided.
(9 VAC 5-50-30 F and 9 VAC 5-80-1180)

47. **Visible Emissions Evaluation** (Ref. Nos. EDG1, EDG2, and EDG3)
Upon request by the DEQ, the permittee shall conduct a visible emissions evaluation (VEE) on the emergency diesel generators in accordance with 40 CFR Part 60, Appendix A, Method 9, to demonstrate compliance with the applicable visible emission limits contained in this permit. The details of the VEE shall be arranged with the Regional Air Compliance Manager of the DEQ's NRO.
(9 VAC 5-50-30 and 9 VAC 5-80-1200)

48. **Natural Gas's Nitrogen and Sulfur Content** – Continuing Compliance (Ref. Nos. Unit 1 and Unit 2)

A. The permittee's custom fuel monitoring schedule for Unit 1 and Unit 2 has received approval from the Environmental Protection Agency (EPA) in accordance with 40 CFR Part 60, Subpart GG. The EPA approval letter is attached in Appendix D of this permit and is considered a part of this permit. The permittee's custom fuel schedule is as follows:

i. The permittee will follow all applicable sulfur content determinations for pipeline natural gas in 40 CFR Part 75, Appendix D.

ii. The requirement to determine the nitrogen content of the pipeline natural gas is waived.

B. The permittee recognizes that Subpart GG establishes the following sulfur dioxide (SO_2) emissions limitations:

i. No owner or operator shall cause to be discharged into the atmosphere from any stationary gas turbine any gasses containing SO_2 in excess of 0.015% by volume at 15% oxygen and on a dry basis; or,

ii. No owner or operator shall burn in any stationary gas turbine any fuel which contains sulfur in excess of 0.8% by weight.

C. If there is a change in fuel supply the permittee must notify the Regional Air Compliance Manager of the DEQ's NRO (at the address referenced in Condition 25) of such change for re-examination of this custom fuel monitoring schedule. A change in fuel quality may be deemed a change in fuel supply. Sulfur monitoring shall be conducted weekly during the interim period when this custom fuel monitoring schedule is being re-examined.

D. As per 40 CFR 60.334(h)(3) and not withstanding 40 CFR 60.334(h)(1), the owners or operators may elect not to monitor more frequently than once per year (40 CFR 75, Appendix D, Section 2.3.1.4 or 2.3.2.4) for the total sulfur content of the gaseous fuel combusted in a turbine if the gaseous fuel is demonstrated to meet the definition of natural gas in 60.331(u), regardless of whether an existing custom schedule approved by the administrator for Subpart GG requires such monitoring. The owner or operator shall use one of the following sources of information to make the required demonstration:

i. The gas quality characteristics in a current valid purchase contract, tariff sheet or transportation contract for gaseous fuel specifying that the maximum total sulfur content of the fuel is 20.0 grains/100 scf or less; or

ii. Have representative fuel sampling data which shows that the sulfur content of the gaseous fuel does not exceed 20.0 grains/100 scf. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of Appendix D to 40 CFR 75 shall be obtained.

These records shall be available on-site for inspection by the DEQ and kept on file for the most current five year period.
(9 VAC 5-50-30 G, 9 VAC 5-80-410 and EPA letter dated 12/17/02)

49. **No. 2 Fuel Oil's Nitrogen and Sulfur Content** – Continuing Compliance (Ref. Nos. Unit 1 and Unit 2)
Prior to combustion, the permittee shall test the No.2 distillate fuel oil for sulfur (and nitrogen content if the source chooses to account for the FBN allowance provided in NSPS Subpart GG), on each occasion that fuel is transferred (as referenced in Appendix A of this permit) to the storage tank, from any other source. Fuel oil sulfur content shall be determined using ASTM D 2880-78, ASTM D 2880-96 or another approved ASTM method incorporated in 40 CFR 60.17 by reference or incorporated in 40 CFR 60.355(b)(10)(i). If applicable, fuel oil nitrogen content shall be determined by following current ASTM procedures approved by the Administrator of the EPA. Any deviations to test methods used by the permittee to determine sulfur and nitrogen content shall be submitted to the Regional Air Compliance Manager for the DEQ's NRO, at the address listed in Condition 25, for approval.

Records of the fuel oil sulfur and nitrogen content shall be available on-site for inspection by DEQ personnel. They shall be kept on file for the most current five year period.
(9 VAC 5-50-30 G)

RECORDS

50. **On Site Records** (Ref. Nos. Units 1 – 5, PH3, and PH4)

The permittee shall maintain records of emission data and operating parameters as necessary to demonstrate compliance with this permit. The content and format of such records shall be arranged with the Regional Air Compliance Manager of the DEQ's NRO at the address referenced in the Condition 25. These records shall include, but are not limited to the following:

A. Fuel records to demonstrate compliance with Conditions 13-20, 48 and 49.

B. The hourly fuel consumption (in scf/hour and gallons/hour) of each CT (when in operation) as required in Condition 42.

C. Data and calculations necessary to demonstrate compliance with the emission limits contained in Conditions 28 – 36.

D. Scheduled and unscheduled maintenance and operator training, as required in Condition 58.

E. To demonstrate compliance with Conditions 13 – 19, all valid purchase contracts, tariff sheets or transportation contracts for the fuels, specifying that the maximum sulfur content for the fuels is 20.0 grains of sulfur or less per 100 standard cubic feet for natural gas, and that the fuel oil contains 500 parts per million (ppm) or less sulfur, and that the diesel fuel oil contains 15 ppm or less sulfur

F. All records of VEOs shall be recorded and shall contain the date, time, results of the VEO, description of any modifications and/or repairs, if necessary to correct any problem, and all follow-up VEE records including name of certified observer, date, time, results of follow-up VEE and operating parameters necessary to demonstrated compliance with this permit. The content of and format of such records shall be arranged with the Regional Air Compliance Manager of the DEQ's NRO.

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

51. **On Site Records** (Ref. Nos. EDG1, EDG2 and EDG3)
The permittee shall maintain records of emission data and operating parameters as necessary to demonstrate compliance with this permit. The content and format of such records shall be arranged with the Regional Air Compliance Manager of the DEQ's NRO. These records shall include, but are not limited to:

A. Annual hours of operation of each engine-generator set, calculated monthly as the sum of each consecutive 12 month period. Compliance for the consecutive 12 month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months.

B. All fuel supplier certifications.

C. Engine information including make, model, serial number, model year, maximum engine power (bhp), and engine displacement for each engine-generator set.

D. The manufacturer's written operating instructions or procedures developed by the owner/operator that are approved by the engine manufacturer for each engine-generator set.

E. Records of the reasons for operation for each engine-generator set, including, but not limited to, the date, cause of operation, and the hours of operation.

F. Results of all stack tests and visible emission evaluations.

G. Scheduled and unscheduled maintenance and operator training.

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

NOTIFICATIONS

52. **Initial Notifications** (Ref. Nos. EDG1, EDG2 and EDG3)
The permittee shall furnish written notification to the Regional Air Compliance Manager of the DEQ's NRO of:

A. The actual date on which construction of the engine-generator sets commenced within 30 days after such date.

B. The anticipated start-up date of the engine-generator sets postmarked not more than 60 days nor less than 30 days prior to such date.

C. The actual start-up date of the engine-generator sets within 15 days after such date. The actual start-up date shall be the date on which each engine completes manufacturer's trials, but shall be no later than thirty days after the initial start up for manufacturer's trials.

Copies of the written notification referenced in items A through C above are to be sent to:

Associate Director
Office of Air Enforcement and Compliance Assistance (3AP20)
U.S. Environmental Protection Agency
Region III
1650 Arch Street
Philadelphia, PA 19103-2029

(9 VAC 5-80-1180 and 9 VAC 5-50-50)

53. **Excess Emissions –** Re-tuning (Ref. Nos. Units 1 – 5)

A. The permittee shall notify the Regional Air Compliance Manager of the DEQ's NRO (at the address referenced in Condition 25), no less than twenty-four hours prior to each CT's re-tuning event. The notification shall include, but is not limited to, the following information.

   i. Identification of the specific CT to be re-tuned.

   ii. Reason for the re-tuning event.

   iii. Measures that will be taken to minimize the length of the re-tuning event.

B. The permittee shall furnish a written report to the Regional Air Compliance Manager of the DEQ's NRO (at the address referenced in Condition 25) of all pertinent facts concerning the re-tuning event, as soon as practicable but not later than fourteen business days after the re-tuning event. The notification shall include, but is not limited to, the following information.

   i. Identification of the CT that was re-tuned.

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

C. NO_X emissions during each CT's re-tuning event shall be recorded and included in the associated quarterly reports and in the total annual emissions as required in Conditions 32, 33, and 42.

D. The re-tuning event for each CT shall be identified on the Data Acquisition Report.

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

54. **Excess Emissions** – Malfunctions (Ref. Nos. Units 1 – 5)
Excess emissions resulting from the malfunction shall be permitted provided that:

A. (Units 1 – 5) – Best operational practices are adhered to and the duration of excess emissions shall be minimized

B. (Unit 1 and Unit 2) – During each malfunction, NO_X emission concentrations based on an hourly average shall not exceed the NO_X standards of the New Source Performance Standards (NSPS) 40 CFR 60 Subpart GG - Standards of Performance for Stationary Gas Turbines (60.330 et seq.).

C. (Units 3 – 5) – During each malfunction, NO_X emission concentrations based on an hourly average shall not exceed the NO_X standards of the New Source Performance Standards (NSPS) 40 CFR 60 Subpart KKKK - Standards of Performance for Stationary Combustion Turbines (60.4300 et seq.).

D. (Units 1 – 5) – The permittee shall notify (at the address referenced in Condition 25) the Regional Air Compliance Manager of the DEQ's NRO within four daytime business hours after a malfunction is discovered. The notification shall include, but is not limited to, the following information.

i. Identification of the specific CT experiencing the malfunction.

ii. The nature and quantity of emissions of air pollutants likely to have occurred during the malfunction.

iii. Measures that will be taken to minimize the length of the malfunction.

E. (Units 1- 5) – As per Conditions 42, 58, and 59 the permittee shall furnish a written report to the Regional Air Compliance Manager of the DEQ's NRO (at the address referenced in Condition 25) of all pertinent facts concerning the malfunction. The notification shall include, but is not limited to, the following information.

i. Identification of the CT that experienced the malfunction.

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

F. (Ref. Nos. Units 1 – 5) – NO_X emissions during each malfunction shall be recorded and included in the total annual emissions as listed in Conditions 32 and 33.

G. (Ref. Nos. Units 1 – 5) – The malfunction for each CT shall be identified on the Data Acquisition Report.

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

GENERAL CONDITIONS

55. **Certification of Documents**

A. The following documents submitted to the board shall be signed by a responsible official: (i) any emission statement, application, form, report, or compliance certification; (ii) any document required to be signed by any provision of the regulations of the board; or (iii) any other document containing emissions data or compliance information the owner wishes the board to consider in the administration of its air quality programs. A responsible official is defined as follows:

i. For a business entity, such as a corporation, association or cooperative, a responsible official is either:

a The president, secretary, treasurer, or a vice president of the business entity in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the business entity; or

b A duly authorized representative of such business entity if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit and either (i) the facilities employ more than 250 persons or have gross annual sales or expenditures exceeding $25 million (in second quarter 1980 dollars) or (ii) the authority to sign documents has been assigned or delegated to such representative in accordance with procedures of the business entity.

ii. For a partnership or sole proprietorship, a responsible official is a general partner or the proprietor, respectively.

iii. For a municipality, state, federal, or other public agency, a responsible official is either a principal executive officer or ranking elected official. A principal executive officer of a federal agency includes the chief executive officer having responsibility for the overall operations of the principal geographic unit of the agency.

B. Any person signing a document under subsection A above shall make the following 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 managed 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."

C. Subsection B shall be interpreted to mean that the signer must have some form of direction or supervision over the persons gathering the data and preparing the document (the preparers), although the signer need not personally nor directly supervise these activities. The signer need not be in the same line of authority as the preparers, nor do the persons gathering the form need to be employees (e.g., outside contractors can be used). It is sufficient that the signer has authority to assure that the necessary actions are taken to prepare a complete and accurate document.

(9 VAC 5-20-230)

56. **Permit Suspension/Revocation**
This permit may be suspended or revoked if the permittee:

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

B. Fails to comply with the conditions of this permit;

C. Fails to comply with any emission standards applicable to a permitted an emissions unit, included in this permit;

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

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

(9 VAC 5-80-1210 F)

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

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

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

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

D. To sample or test at reasonable times.

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

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

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

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

B. Maintain an inventory of spare parts.

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

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

Records of maintenance and training shall be maintained on site for a period of five years and shall be made available to DEQ personnel upon request.
(9 VAC 5-50-20 E and 9 VAC 5-80-1180 D)

59. **Record of Malfunctions**
The permittee shall maintain records of the occurrence and duration of any bypass, malfunction, shutdown or failure of the facility or its associated air pollution control equipment that results in excess emissions for more than one hour. Records shall include the date, time, duration, description (emission unit, pollutant affected, cause), corrective action, preventive measures taken and name of person generating the record.
(9 VAC 5-20-180 J and 9 VAC 5-80-1180 D)

60. **Notification for Facility or Control Equipment Malfunction**
The permittee shall furnish notification to the Regional Air Compliance Manager of the DEQ's NRO (at the address referenced in Condition 25), of malfunctions of the affected

facility or related air pollution control equipment that may cause excess emissions for more than one hour, by e-mail, facsimile transmission, telephone or telegraph. Such notification shall be made as soon as practicable but no later than four daytime business hours after the malfunction is discovered. The permittee shall provide a written statement giving all pertinent facts, including the estimated duration of the breakdown, within two weeks of discovery of the malfunction. A permittee subject to the requirements of 9 VAC 5-40-50 C and 9 VAC 5-50-50 C is not required to provide the written two week statement for facilities subject to the monitoring requirements of 9 VAC 5-40-40 and 9 VAC 5-50-40. When the condition causing the failure or malfunction has been corrected and the equipment is again in operation, the permittee shall notify the Regional Air Compliance Manager of the DEQ's NRO.
(9 VAC 5-20-180 C and 9 VAC 5-80-1180)

61. **Notification for Control Equipment Maintenance** (Ref. Nos. Units 1 – 5)

The permittee shall furnish notification to the Regional Air Compliance Manager of the DEQ's NRO (at the address referenced in Condition 25) of the intention to shut down or bypass, or both, air pollution control equipment for necessary scheduled maintenance, which results in excess emissions for more than one hour, at least twenty-four hours prior to the shutdown. The notification shall include, but is not limited to, the following information:

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

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

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

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

(9 VAC 5-20-180 B)

62. **Violation of Ambient Air Quality Standard**
The permittee shall, upon request of the DEQ, reduce the level of operation or shut down a facility, as necessary to avoid violating any primary ambient air quality standard and shall not return to normal operation until such time as the ambient air quality standard will not be violated.
(9 VAC 5-20-180 I and 9 VAC 5-80-1180)

63. **Change of Ownership**
In the case of a transfer of ownership of a stationary source, the new owner shall abide by any current permit issued to the previous owner. The new owner shall notify the Regional Air Compliance Manager of the DEQ's NRO (at the address referenced in Condition 25) of the change of ownership within thirty days of the transfer.(9 VAC 5-80-1240)

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

65. **Permit Invalidation**
The portions of this permit to construct the engine generator sets (Ref. Nos. EDG1, EDG2 and EDG3) shall become invalid, unless an extension is granted by the DEQ, if:

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

b. A program of construction or modification is discontinued for a period of 18 months or more, or is not completed within a reasonable time, except for a DEQ approved period between phases of the phased construction of a new stationary source or project.

(9 VAC 5-80-1210)

APPENDIX A

No.2 Distillate Fuel Oil Shipment/Transfer Procedures

No. 2 Distillate Fuel Oil Transfers

VEPCO – Ladysmith CT station defines fuel oil transfer/shipment as a series of truck transport loads from a vendor's fuel oil tank to the facility's 2,700,000 gallon tanks. Prior to the fuel transfer, the vendor shall supply VEPCO personnel with copies of fuel contracts, tariff sheets and/or bills of laden with a maximum total sulfur specification that meets the definition of No. 2 distillate fuel oil. These certifications will provide, at a minimum, the information required in Condition 20 of this permit. Copies of the fuel supplier certifications shall be retained at the CT site.

Upon receipt of delivered oil, the receiving tank(s) at the CT site will be sampled for sulfur content prior to combustion. The sampling will be done as referenced in Condition 49 of this permit. Copies of these analyses will also be retained at the CT site as required by their permit.

APPENDIX B

ALTERNATE OPERATING SCENARIOS - FUEL TYPE TRANSFER
Excerpt from Facility Operating Procedures

At the CEMS Polling Computer

- ☐ After Unit is on line (approx. 30 minutes after FIRE) verify CEMS initiates a CAL by monitoring the POLLING Computer for "C" flags
- ☐ CEMS will CAL for approx. 25 min.
- ☐ After CAL is complete, check CAL REPORT on polling computer to assure no parameters are OOC.
- ☐ IF a parameter goes OOC during a CAL a "T" flag will appear on that parameter, the Technician MUST put PNOXL, PNOXH and QO2D in MAINT and perform a manual CAL to correct the problem. THEN a "hands off" cal needs to be performed.
- ☐ Check QNOXA15 to make sure that is below 9ppm when on Natural Gas and or 42ppm when on Liquid Fuel.
  - Start up - This must occur within 2 one hour averaging periods (2 CEMS hours).
  - Fuel Transfer - This must occur within 3 one hour averaging periods (3 CEMS hours).
  - Shut Down - This must occur within 2 one hour averaging periods (2 CEMS hours).

  If the unit can not come into compliance within the above time frames the unit must be immediately shut down.
- ☐ All alarms on the CEMS Polling Computer must be addressed immediately to determine cause and appropriate action.

Fuel Transfers

Natural Gas to Liquid Fuel – Auto / Manual Operator Initiated Transfer

- ☐ If Manually transferring fuels lower the load on the Unit (40 - 60MW), Initiate transfer and enter the start time of the transfer in the station log.
- ☐ If Auto transfer due to loss of gas pressure. Select PRESELECTED load to current MW to keep unit from continuing to runback and eventually off line. Enter the start time of the transfer in the station log.
- ☐ Confirm unit has successfully transferred to liquid fuel.
- ☐ Observe Exhaust Spreads and Temperatures, confirm within normal limits.
- ☐ Raise unit load to above Water Injection approximately 80MW.
- ☐ Confirm Water Injection system has started and flow is established.
- ☐ Observe Exhaust Spreads and Temperatures, confirm within normal limits

APPENDIX C

ALTERNATE OPERATING SCENARIOS – RE-TUNING

ALTERNATE OPERATING SCENARIOS – RE-TUNING

Alternate 1 – Units 1 – 5 (Natural Gas)
&
Alternate 2 – Units 1 – 5 (No. 2 Distillate Oil)

In order to meet NO_X emission limits, Units 1 – 5 may require periodic re-tuning based upon maintenance or a change in test methods for fuel-bound nitrogen. Re-tuning may require for either or both fuels. During retuning events, the unit(s) is ramped up at 5 MW increments all the way to 100% load. At each 5 MW increment, the unit(s) is tested and data is collected to produce a control curve for the units control system. The unit(s) is dropped back to minimum load, the new control curve is entered, and then the unit(s) is then ramped back up and data points are taken to ensure that the control curve meets the NO_X emission limits. This process is repeated until the unit is properly tuned. NO_X emissions may exceed short term NOX emission limits during re-tuning events. Re-tuning events are infrequent (typically once every 450 starts or 5 – 12 years; however, could be longer depending on the cause of the re-tuning). Consequently, Dominion is proposing a variance from NO_X emission limits during re-tuning events.

Excess Emissions – Re-tuning: Excess emissions resulting from the re-tuning of the combustion turbines shall be permitted provided that:

D. Best operational practices are adhered to and the duration of excess emissions shall be minimized but in no case exceed twelve hours per combustion turbines re-tuning event in any twenty-four hour period. The operator may request additional hours from the DEQ.

E. During each Unit 1 and Unit 2 re-tuning event, NO_X emission concentrations, based on an hourly average, shall not exceed the NO_X standards of the New Source Performance Standards (NSPS) 40 CFR 60 Subpart GG - Standards of Performance for Stationary Gas Turbines (60.330 et seq.).

F. During each Unit 3, Unit 4, and Unit 5 re-tuning event, NO_X emission concentrations, based on an hourly average, shall not exceed the NO_X standards of the New Source Performance Standards (NSPS) 40 CFR 60 Subpart KKKK - Standards of Performance for Stationary Combustion Turbines (60.4300 et seq.).

G. The permittee shall notify the Regional Air Compliance Manager of the DEQ's NRO, no less than twenty-four hours prior to each combustion turbines re-tuning event. The notification shall include, but is not limited to, the following information.

Identification of the specific combustion turbine to be re-tuned.
Reason for the re-tuning event.
Measures that will be taken to minimize the length of the re-tuning event.

H. The permittee shall furnish a written report to the Regional Air Compliance Manager of the DEQ's NRO of all pertinent facts concerning the re-tuning event, as soon as practicable but not later than fourteen business days after the re-tuning event. The notification shall include, but is not limited to, the following information.

Identification of the combustion turbine that was re-tuned.
The magnitude of excess emissions for each combustion turbine, any conversion factors used in the calculation of the excess emissions, and the date and time of commencement and completion of each period of excess emissions.

I. NO_X emissions during each combustion turbines re-tuning event shall be recorded and included in the associated quarterly reports and in the total annual emissions.

J.
The re-tuning event for each combustion turbine shall be identified on the Data Acquisition Report.

APPENDIX D

CUSTOM FUEL MONITORING SCHEDULE REQUEST AND THE EPA LETTER OF APPROVAL

Effective for Unit 1 and Unit 2 Only
(Units 3, 4, and 5 are subject to 40 CFR 60, Subpart KKKK and not included in this letter)

Dominion Generation

Dominion

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

December 3, 2002

DEC 9 2002

Mr. James Hagedorn
USEPA
Air Protection Division, 3AP12
1650 Arch Street
Philadelphia, PA 19103-2029

Re: Ladysmith Combustion Turbine Station
Custom Fuel Monitoring Schedule

Dear Mr. Hagedorn:

Dominion Generation operates the Ladysmith Combustion Turbine Station located in Caroline County, VA that became operational in June 2001. The two General Electric 7 FA simple-cycle combustion turbines operate primarily on natural gas, but they are capable of combusting distillate fuel oil (low sulfur #2 oil). The units are subject to NSPS Subpart GG, 40 CFR Part 75 (the Acid Rain provisions), and to a Virginia stationary source permit to construct and operate.

We request that EPA Region 3: 1) approve a custom fuel monitoring schedule for the analysis of sulfur in the natural gas combusted at Ladysmith Combustion Turbine Station; 2) approve that samples taken at our Chesterfield Station fulfill the fuel analysis requirement for the Ladysmith Station; and, 3) waive the requirement to analyze nitrogen in the natural gas at the Ladysmith Station.

We request to be relieved of the requirements at 40 CFR 60.334(b) and 60.335(d) to monitor, determine, and record the sulfur content of the fuels fired in the turbines. Instead, the facility proposes to follow applicable sulfur content determination and monitoring requirements for pipeline natural gas and fuel oil in 40 CFR Part 75, Appendix D.

We recognize that Subpart GG establishes the following sulfur dioxide (SO_2) emissions limitations:

- No owner or operator shall cause to be discharged into the atmosphere from any stationary gas turbine any gases containing SO_2 in excess of 0.015% by volume at 15% oxygen and on a dry basis; or,

- No owner or operator shall burn in any stationary gas turbine any fuel which contains sulfur in excess of 0.8% by weight.

As indicated above, we propose to follow applicable sulfur content determination and monitoring requirements in Appendix D of 40 CFR Part 75. Given that the Acid Rain Program is recognized as more stringent than NSPS requirements, compliance with Subpart GG will be readily demonstrated. In a determination dated May 5, 2002 (see EPA Applicability Determination Index, Control Number 0200038, copy attached), EPA Region 3 approved similar requests for Pleasants Energy, LLC and for Armstrong Energy, LLLP, both of which are operated by Dominion.

In a letter dated July 2, 1998, EPA Region 3 approved the custom fuel monitoring schedule for our Darbytown Station (see EPA Applicability Determination Index, Control Number 9800110, copy attached). Our Ladysmith Station is located on the same pipeline that supplies our Darbytown and Chesterfield Stations, as is the Doswell Limited Partnership Station. In that same determination, Region 3 approved the use of natural gas samples taken at our Chesterfield Station to fulfill the fuel analysis requirement for the Darbytown Station. The Doswell facility had previously been granted approval for a custom fuel monitoring schedule (see ADI Control Number 9800053, January 9, 1998, copy attached). Given that at least two determinations have been made regarding natural gas in this pipeline, we request that the custom fuel monitoring schedule be approved without further study or analysis of additional data.

In addition, we request waiving of the requirement to analyze nitrogen in the natural gas.

Please contact Mr. Philip Knause at (804) 273-2946, or via email at Philip_Knause@Dom.com if you have any questions.

Yours Truly,

Cathy C. Taylor

Cathy C. Taylor
Director – Electric Environmental Services

cc: Mr. James LaFratta
VADEQ Fredericksburg Satellite Office
806 Westwood Office Park
Fredericksburg, VA 22401

#40960

UNITED TES ENVIRONMENTAL PROTECTION AGENCY
REGION III
1650 Arch Street
Philadelphia, Pennsylvania 19103-2029

RECEIVED
DEC 19 2002
PUO

DEC 17 2002

Cathy C. Taylor, Director
Dominion Generation Environmental Services
5000 Dominion Boulevard
Glen Allen, irginia. 23060

Dear Ms. Taylor:

The Philadelphia Regional Office of the U.S. Environmental Protection Agency (Region III) has received and reviewed your letter, dated December 3, 2002, requesting approval to use several alternative monitoring methods to the ones specified under Subpart GG of Part 60 for emission sources covered by the New Source Performance Standards (NSPS) program at the Company's Ladysmith Combustion Turbine Station. Dominion operates two General Electric FA simple cycle combustion turbines at the station that primarily burn natural gas but do have the capability of burning distillate fuel oil #2. The Company is specifically requesting that EPA approve; 1) a custom fuel monitoring schedule for sulfur analysis for the pipeline-quality natural gas combusted in the turbines; 2) the use of Chesterfield Station samples for showing pipeline gas sulfur content; 3) a waiver of the requirement to monitor natural gas nitrogen content; and 4) approval to use the Acid Rain Part 75, Appendix D procedures for measuring the sulfur content in both the natural gas and distillate fuel oil combusted in the turbines.

After careful consideration of the facts presented in the Company's December letter, Region III has decided to approve these requests since similar requests have been approved in the past by EPA in both Region III and other EPA Regional Offices for similarly situated stations. These approvals are consistent with past EPA determinations as currently presented on the Agency's Applicability Determination Index database. EPA's 1987 National Policy covering Subpart GG gas turbines acknowledges the fact that fuel bound nitrogen in pipeline-quality natural gas fuel does not appreciably contribute to the formation of nitrogen oxides upon combustion. Another factor taken into consideration is the fact that Region III has already approved similar exemptions and alternatives for other turbine stations that also combust the same natural gas fuel as the Ladysmith Station from the same gas pipeline. If you should have any comments or questions in regard to this matter, do not hesitate to contact James W. Hagedorn, of my staff, at (215) 814-2161.

Sincerely,

Judith M. Katz, Director
Air Protection Division

cc: Jim LaFratta, VADEQ-Fredericksburg Office

Attachment C

Emission Factors and Calculation Methods

Attachment C
Emission Factors and Calculation Methods

Combustion Turbine (CT) - Unit 1

Natural Gas		
Pollutant	Factor (lb/MMBtu fuel input)	Source
PM	13.2	AP-42, Table 3.1-2a, 5th Ed 4/00
PM-10	13.2	Assumes all PM is PM-10
PM-2.5	13.2	Assumes all of PM-10 is PM-2.5
CO	1.6	Factor taken from the emissions test peak load run; the heat input value to develop the factor was also taken from the peak load run.
VOC	4.2	AP-42, Table 3.1-2a, 5th Ed 4/00
SO2	--	SO2 emissions calculated by the CEM DAHS - Part 75, Appendix D, Equation D-5
NOx	--	NOx CEMS

Distillate Oil		
Pollutant	Factor (lb/MMBtu fuel input)	Source
PM	24	AP-42, Table 3.1-2a, 5th Ed 4/00
PM-10	24	Assumes all PM is PM-10
PM-2.5	24	Assumes all of PM-10 is PM-2.5
CO	3	Factor taken from the emissions test peak load run; the heat input value to develop the factor was also taken from the peak load run.
VOC	0.82	AP-42, Table 3.1-2a, 5th Ed 4/00
SO2	--	SO2 emissions calculated by the CEM DAHS - Part 75, Appendix D, Equation D-5
NOx	--	NOx CEMS

Combustion Turbine (CT) - Unit 2

Natural Gas		
Pollutant	Factor (lb/MMBtu fuel input)	Source
PM	13.2	AP-42, Table 3.1-2a, 5th Ed 4/00
PM-10	13.2	Assumes all PM is PM-10
PM-2.5	13.2	Assumes all of PM-10 is PM-2.5
CO	1.8	Factor taken from the emissions test peak load run; the heat input value to develop the factor was also taken from the peak load run.
VOC	4.2	AP-42, Table 3.1-2a, 5th Ed 4/00
SO2	--	SO2 emissions calculated by the CEM DAHS - Part 75, Appendix D, Equation D-5
NOx	--	NOx CEMS

Distillate Oil		
Pollutant	Factor (lb/MMBtu fuel input)	Source
PM	24	AP-42, Table 3.1-2a, 5th Ed 4/00
PM-10	24	Assumes all PM is PM-10
PM-2.5	24	Assumes all of PM-10 is PM-2.5
CO	9.8	Factor taken from the emissions test peak load run; the heat input value to develop the factor was also taken from the peak load run.
VOC	0.82	AP-42, Table 3.1-2a, 5th Ed 4/00
SO2	--	SO2 emissions calculated by the CEM DAHS - Part 75, Appendix D, Equation D-5
NOx	--	NOx CEMS

Combustion Turbine (CT) - Unit 3

Natural Gas		
Pollutant	Factor (lb/MMBtu fuel input)	Source
PM	13.2	AP-42, Table 3.1-2a, 5th Ed 4/00
PM-10	13.2	Assumes all PM is PM-10
PM-2.5	13.2	Assumes all of PM-10 is PM-2.5
CO	30	AP-42, Table 3.1-1 (natural gas fired, Lean Pre Mix factor)
VOC	4.2	AP-42, Table 3.1-2a, 5th Ed 4/00
SO2	--	Part 75, Appendix D: Optional SO2 Emissions Data Protocol for Gas-Fired and Oil-Fired Units
NOx	--	NOx CEMS

Combustion Turbine (CT) - Unit 3 (continued)

Distillate Oil		
Pollutant	Factor (lb/MMBtu fuel input)	Source
PM	24	AP-42, Table 3.1-2a, 5th Ed 4/00
PM-10	24	Assumes all PM is PM-10
PM-2.5	24	Assumes all of PM-10 is PM-2.5
CO	152	AP-42, Table 3.1-1 (water/steam injection)
VOC	0.82	AP-42, Table 3.1-2a, 5th Ed 4/00
SO2	--	Part 75, Appendix D: Optional SO2 Emissions Data Protocol for Gas-Fired and Oil-Fired Units
NOx	--	NOx CEMS

Combustion Turbine (CT) - Unit 4

Natural Gas		
Pollutant	Factor (lb/MMBtu fuel input)	Source
PM	13.2	AP-42, Table 3.1-2a, 5th Ed 4/00
PM-10	13.2	Assumes all PM is PM-10
PM-2.5	13.2	Assumes all of PM-10 is PM-2.5
CO	30	AP-42, Table 3.1-1 (natural gas fired, Lean Pre Mix factor)
VOC	4.2	AP-42, Table 3.1-2a, 5th Ed 4/00
SO2	--	Part 75, Appendix D: Optional SO2 Emissions Data Protocol for Gas-Fired and Oil-Fired Units
NOx	--	NOx CEMS

Distillate Oil		
Pollutant	Factor (lb/MMBtu fuel input)	Source
PM	24	AP-42, Table 3.1-2a, 5th Ed 4/00
PM-10	24	Assumes all PM is PM-10
PM-2.5	24	Assumes all of PM-10 is PM-2.5
CO	152	AP-42, Table 3.1-1 (water/steam injection)
VOC	0.82	AP-42, Table 3.1-2a, 5th Ed 4/00
SO2	--	Part 75, Appendix D: Optional SO2 Emissions Data Protocol for Gas-Fired and Oil-Fired Units
NOx	--	NOx CEMS

Combustion Turbine (CT) - Unit 5

Natural Gas		
Pollutant	Factor (lb/MMBtu fuel input)	Source
PM	13.2	AP-42, Table 3.1-2a, 5th Ed 4/00
PM-10	13.2	Assumes all PM is PM-10
PM-2.5	13.2	Assumes all of PM-10 is PM-2.5
CO	1.2	Factor from April 2, 2009 stack test
VOC	4.2	AP-42, Table 3.1-2a, 5th Ed 4/00
SO2	--	SO2 emissions calculated by the CEM DAHS - Part 75, Appendix D, Equation D-5
NOx	--	NOx CEMS

Distillate Oil		
Pollutant	Factor (lb/MMBtu fuel input)	Source
PM	24	AP-42, Table 3.1-2a, 5th Ed 4/00
PM-10	24	Assumes all PM is PM-10
PM-2.5	24	Assumes all of PM-10 is PM-2.5
CO	1.4	Factor from April 2, 2009 stack test
VOC	0.82	AP-42, Table 3.1-2a, 5th Ed 4/00
SO2	--	SO2 emissions calculated by the CEM DAHS - Part 75, Appendix D, Equation D-5
NOx	--	NOx CEMS

Pipeline Heaters - PH3 and PH4

Natural Gas		
Pollutant	Factor (lb/MMscf	Source
PM	7.6	AP-42, Table 1.4-2 (7/98)
PM-10	7.6	Assumes all PM is PM-10
PM-2.5	7.6	Assumes all of PM-10 is PM-2.5
CO	84	AP-42, Table 1.4-1 (7/98)
VOC	2.8	AP-42, Table 1.4-2 (7/98)
SO2	0.6	AP-42, Table 1.4-2 (7/98)
NOx	140	AP-42, Table 1.4-1 (7/98)

Attachment D

Title IV Acid Rain Permit Application

Dominion Resources Services, Inc.
5000 Dominion Boulevard, Glen Allen, VA 23060
Web Address: www.dom.com

Dominion®

CERTIFIED MAIL, RETURN RECEIPT REQUESTED

June 19, 2014

Mr. Jim LaFratta
Air Permit Manager
Virginia Department of Environmental Quality
Northern Virginia Regional Office
13901 Crown Court
Woodbridge, VA 22193

RE: **Ladysmith Power Station: Acid Rain Renewal Application DEQ Air Reg. 40960**

Dear Mr. LaFratta:

Enclosed please find the Acid Rain renewal application for Ladysmith CT Station. A copy of the Certificate of Representation report from the CAMD website has also been included for your reference.

If you have any questions, please feel free to contact Liz Willoughby at (804) 273-3740 or Elizabeth.A.Willoughby@dom.com.

Sincerely,

Cathy C. Taylor

Cathy C. Taylor
Director, Electric Environmental Services

Enclosures: Ladysmith CT Station Acid Rain Permit Application
Certificate of Representation

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258
Approval expires 11/30/2012

Acid Rain Permit Application

For more information, see instructions and 40 CFR 72.30 and 72.31.

This submission is: ~ new ~ revised X for Acid Rain permit renewal

STEP 1

Identify the facility name, State, and plant (ORIS) code.

Dominion - Ladysmith CT Station	VA	7838

STEP 2

Enter the unit ID# for every affected unit at the affected source in column "a."

a	b
Unit ID#	Unit Will Hold Allowances in Accordance with 40 CFR 72.9(c)(1)
1	Yes
2	Yes
3	Yes
4	Yes
5	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes

Dominion - Ladysmith CT station

Permit Requirements

STEP 3

Read the standard requirements.

(1) The designated representative of each affected source and each affected unit at the source shall:

(i) Submit a complete Acid Rain permit application (including a 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;

(2) 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.

Monitoring Requirements

(1) 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.

(2) 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.

(3) 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 Act and other provisions of the operating permit for the source.

Sulfur Dioxide Requirements

(1) 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) Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.

(2) Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act.

(3) An affected unit shall be subject to the requirements under paragraph (1) of the sulfur dioxide requirements as follows:

(i) Starting January 1, 2000, an affected unit under 40 CFR 72.6(a)(2); or

(ii) Starting on the later of January 1, 2000 or the deadline for monitor certification under 40 CFR part 75, an affected unit under 40 CFR 72.6(a)(3).

Sulfur Dioxide Requirements, Cont'd.

STEP 3, Cont'd.

(4) Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.
(5) An allowance shall not be deducted in order to comply with the requirements under paragraph (1) of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.
(6) An allowance allocated by the 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.
(7) An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

Nitrogen Oxides Requirements

The owners and operators of the source and each affected unit at the source shall comply with the applicable Acid Rain emissions limitation for nitrogen oxides.

Excess Emissions Requirements

(1) 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.
(2) 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.

Recordkeeping and Reporting Requirements

(1) 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;

Recordkeeping and Reporting Requirements, Cont'd.

STEP 3, Cont'd.

(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.

(2) 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.

Liability

(1) 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 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 Act.
(2) 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 Act and 18 U.S.C. 1001.
(3) 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.
(4) Each affected source and each affected unit shall meet the requirements of the Acid Rain Program.
(5) 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.
(6) 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.
(7) Each violation of a provision of 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 Act.

Effect on Other Authorities

No provision of the Acid Rain Program, an Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 shall be construed as:
(1) Except as expressly provided in title IV of the 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 Act, including the provisions of title I of the Act relating

Dominion - Ladysmith CT station

Effect on Other Authorities, Cont'd.

STEP 3, Cont'd.

to applicable National Ambient Air Quality Standards or State Implementation Plans;
(2) 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 Act;
(3) 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;
(4) Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or,
(5) Interfering with or impairing any program for competitive bidding for power supply in a State in which such program is established.

Certification

STEP 4
Read the certification statement, sign, and date.

I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name Jeffrey Heffelman	
Signature [signature]	Date 6-18-14

Back Print

Reports and Queries
Certificate of Representation
09/09/2013

Facility Information

Facility ID (ORISPL):	7839	**Facility Name:**	Ladysmith Combustion Turbine Sta	**State:**	VA		
County:	Caroline	**EPA AIRS ID:**	5103300040	**Latitude:**	38.5442	**Longitude:**	-77.7714

Facility Detail (Mini Detail)

Primary Representative Information

Name: Edward H Baine
Company: Dominion Resources Services, Inc
Title: Vice President Power Generation System Operations
Address: VA 23060
Phone: (804) 273-3592
Fax: (804) 273-3714
Alternate:
Email: dominion.system.dr@dom.com

People Detail Layout (Multiple)

Alternate Representative Information

Name: Jeffrey C Heffelman
Company: Virginia Electric & Power Company
Title: Director, F & H Station II
Address: VA 22026
Phone: (703) 441-3880
Fax: (703) 441-3897
Alternate:
Email: jeffrey.c.heffelman@dom.com

People Detail Layout (Multiple)

Current Representatives

Program	Primary Representative, Effective Date	Alternate Representative, Effective Date	Primary Representative, End Date	Alternate Representative, End Date
ARP	Edward H Baine, 06/28/2013	Jeffrey C Heffelman, 04/08/2011		
CAIRNOX	Edward H Baine, 06/28/2013	Jeffrey C Heffelman, 04/08/2011		
CAIROS	Edward H Baine, 06/28/2013	Jeffrey C Heffelman, 04/08/2011		
CAIRSO2	Edward H Baine, 06/28/2013	Jeffrey C Heffelman, 04/08/2011		
TRNOX	Edward H Baine, 06/28/2013	Jeffrey C Heffelman, 09/27/2011		
TRNOXOS	Edward H Baine, 06/28/2013	Jeffrey C Heffelman, 09/27/2011		

TRSO2G1	Edward H Baine, 06/28/2013	Jeffrey C Heffelman, 09/27/2011			

Basic Table Layout

Units

Unit ID	Program	Unit Classification	Operating Status	Unit Type	Indian Country	Source Category	NAICS Code	Commence Operation Date	Commence Operation Date Code	Comm. Commercial Operation Date	Commence Commericial Operation Date Code	Unit Monitoring Certification Begin Date
1	ARP	Phase 2	Operating	CT	No	Electric Utility	Fossil fuel electric power generation	05/31/2001	A	05/31/2001	A	05/31/2001
1	CAIRNOX	Affected	Operating	CT	No	Electric Utility	Fossil fuel electric power generation	05/31/2001	A	05/31/2001	A	01/01/2008
1	CAIROS	Affected	Operating	CT	No	Electric Utility	Fossil fuel electric power generation	05/31/2001	A	05/31/2001	A	05/01/2008
1	CAIRSO2	Affected	Operating	CT	No	Electric Utility	Fossil fuel electric power generation	05/31/2001	A	05/31/2001	A	01/01/2009
1	NBP	Affected	Operating	CT	No	Electric Utility	Fossil fuel electric power generation	05/31/2001	A	05/31/2001	A	05/01/2003
1	TRNOX	Affected	Operating	CT	No	Electric Utility	Fossil fuel electric power generation	05/31/2001	A	05/31/2001	A	01/01/2012
1	TRNOXOS	Affected	Operating	CT	No	Electric Utility	Fossil fuel electric power generation	05/31/2001	A	05/31/2001	A	05/01/2012
1	TRSO2G1	Affected	Operating	CT	No	Electric Utility	Fossil fuel electric power generation	05/31/2001	A	05/31/2001	A	01/01/2012
2	ARP	Phase 2	Operating	CT	No	Electric Utility	Fossil fuel electric power generation	05/23/2001	A	05/23/2001	A	05/23/2001
2	CAIRNOX	Affected	Operating	CT	No	Electric Utility	Fossil fuel electric power generation	05/23/2001	A	05/23/2001	A	01/01/2008
2	CAIROS	Affected	Operating	CT	No	Electric Utility	Fossil fuel electric power generation	05/23/2001	A	05/23/2001	A	05/01/2008
2	CAIRSO2	Affected	Operating	CT	No	Electric Utility	Fossil fuel electric power generation	05/23/2001	A	05/23/2001	A	01/01/2009
2	NBP	Affected	Operating	CT	No	Electric Utility	Fossil fuel electric power generation	05/23/2001	A	05/23/2001	A	05/01/2003
2	TRNOX	Affected	Operating	CT	No	Electric Utility	Fossil fuel electric power generation	05/23/2001	A	05/23/2001	A	01/01/2012
2	TRNOXOS	Affected	Operating	CT	No	Electric Utility	Fossil fuel electric power generation	05/23/2001	A	05/23/2001	A	05/01/2012
2	TRSO2G1	Affected	Operating	CT	No	Electric Utility	Fossil fuel electric power generation	05/23/2001	A	05/23/2001	A	01/01/2012

3	ARP	Phase 2	Operating	CT	No	Electric Utility	Fossil fuel electric power generation	05/19/2008	A	05/22/2008	A	05/22/2008
3	CAIRNOX	Affected	Operating	CT	No	Electric Utility	Fossil fuel electric power generation	05/19/2008	A	05/22/2008	A	05/22/2008
3	CAIROS	Affected	Operating	CT	No	Electric Utility	Fossil fuel electric power generation	05/19/2008	A	05/22/2008	A	05/22/2008
3	CAIRSO2	Affected	Operating	CT	No	Electric Utility	Fossil fuel electric power generation	05/19/2008	A	05/22/2008	A	01/01/2009
3	NBP	Affected	Operating	CT	No	Electric Utility	Fossil fuel electric power generation	05/19/2008	A	05/22/2008	A	05/19/2008
3	TRNOX	Affected	Operating	CT	No	Electric Utility	Fossil fuel electric power generation	05/19/2008	A	05/22/2008	A	01/01/2012
3	TRNOXOS	Affected	Operating	CT	No	Electric Utility	Fossil fuel electric power generation	05/19/2008	A	05/22/2008	A	05/01/2012
3	TRSO2G1	Affected	Operating	CT	No	Electric Utility	Fossil fuel electric power generation	05/19/2008	A	05/22/2008	A	01/01/2012
4	ARP	Phase 2	Operating	CT	No	Electric Utility	Fossil fuel electric power generation	06/03/2008	A	06/07/2008	A	06/07/2008
4	CAIRNOX	Affected	Operating	CT	No	Electric Utility	Fossil fuel electric power generation	06/03/2008	A	06/07/2008	A	06/07/2008
4	CAIROS	Affected	Operating	CT	No	Electric Utility	Fossil fuel electric power generation	06/03/2008	A	06/07/2008	A	06/07/2008
4	CAIRSO2	Affected	Operating	CT	No	Electric Utility	Fossil fuel electric power generation	06/03/2008	A	06/07/2008	A	01/01/2009
4	NBP	Affected	Operating	CT	No	Electric Utility	Fossil fuel electric power generation	06/03/2008	A	06/07/2008	A	06/03/2008
4	TRNOX	Affected	Operating	CT	No	Electric Utility	Fossil fuel electric power generation	06/03/2008	A	06/07/2008	A	01/01/2012
4	TRNOXOS	Affected	Operating	CT	No	Electric Utility	Fossil fuel electric power generation	06/03/2008	A	06/07/2008	A	05/01/2012
4	TRSO2G1	Affected	Operating	CT	No	Electric Utility	Fossil fuel electric power generation	06/03/2008	A	06/07/2008	A	01/01/2012
5	ARP	Phase 2	Operating	CT	No	Electric Utility	Fossil fuel electric power generation	03/19/2009	A	03/22/2009	A	03/22/2009
5	CAIRNOX	Affected	Operating	CT	No	Electric Utility	Fossil fuel electric power generation	03/19/2009	A	03/22/2009	A	03/22/2009
5	CAIROS	Affected	Operating	CT	No	Electric Utility	Fossil fuel electric	03/19/2009	A	03/22/2009	A	03/22/2009

							power generation					
5	CAIRSO2	Affected	Operating	CT	No	Electric Utility	Fossil fuel electric power generation	03/19/2009	A	03/22/2009	A	03/22/2009
5	TRNOX	Affected	Operating	CT	No	Electric Utility	Fossil fuel electric power generation	03/19/2009	A	03/22/2009	A	01/01/2012
5	TRNOXOS	Affected	Operating	CT	No	Electric Utility	Fossil fuel electric power generation	03/19/2009	A	03/22/2009	A	05/01/2012
5	TRSO2G1	Affected	Operating	CT	No	Electric Utility	Fossil fuel electric power generation	03/19/2009	A	03/22/2009	A	01/01/2012

Basic Table Layout

Generator Information

Generator ID	Unit ID	ARP Nameplate Capacity	CAIR/Transport Rule Nameplate Capacity	Effective Date
1	1	178.5	178.5	06/04/2007
2	2	178.5	178.5	06/04/2007
3	3	192.1	192.1	01/08/2008
4	4	192.1	192.1	01/08/2008
5	5	192.1	192.1	01/08/2008

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Current Owners and Operators

Unit ID	Owner/Operator Company Name	Type	Effective Date	End Date
1	Dominion Generation	Operator	03/07/2003	
1	Virginia Electric & Power Company	Owner	03/07/2003	
2	Dominion Generation	Operator	03/07/2003	
2	Virginia Electric & Power Company	Owner	03/07/2003	
3	Dominion Generation	Operator	12/26/2007	
3	Virginia Electric & Power Company	Owner	12/26/2007	
4	Dominion Generation	Operator	12/26/2007	
4	Virginia Electric & Power Company	Owner	12/26/2007	
5	Dominion Generation	Operator	01/08/2008	
5	Virginia Electric & Power Company	Owner	01/08/2008	

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