COMMONWEALTH OF VIRGINIA
Department of Environmental Quality
Northern Regional Office

STATEMENT OF LEGAL AND FACTUAL BASIS

Old Dominion Electric Cooperative (ODEC)
Louisa Generation Facility
4201 Dominion Boulevard
Glen Allen, Virginia
Permit No. NRO40989

Title IV of the 1990 Clean Air Act Amendments required each state to develop a permit program to ensure that certain electrical generation facilities have federal Air Pollution Operating Permits, called Title IV 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, Old Dominion Electric Cooperative (ODEC) has applied for a renewal of the Title IV Operating Permit for its Louisa Generation Facility ("LGF"). The Department has reviewed the application and has prepared a Federal Operating Permit. This permit is based upon Federal Clean Air Act Acid Rain permitting requirements of Title IV, federal operating permit requirements of Title V, and Chapter 80, Article 3 of the Commonwealth of Virginia Regulations for the Control and Abatement of Air Pollution.

Engineer/Permit Contact: Laura R. Justin   Date: 12-11-15
Laura R. Justin
(540) 574-7857

Air Permit Manager: James B. LaFratta   Date: 12/14/2015
James LaFratta

Regional Director: Thomas A. Faha   Date: 12/14/15
Thomas A. Faha

FACILITY INFORMATION

<u>Permittee</u>
Old Dominion Electric Cooperative
4201 Dominion Boulevard
Glen Allen, VA 23060

<u>Facility</u>
ODEC – Louisa Generation Facility
3352 Klockner Road
Gordonsville, VA 22942

County-Plant Identification Number: 51-109-00050

SOURCE DESCRIPTION

Facility Description: NAICS Code 221112 (Electric Power Generation)

The Louisa Generation Facility, located in Louisa County, is a nominal 600 megawatt (MW) peaking power station consisting of five simple cycle, dual fuel, combustion turbines (CT). Four of the units are General Electric (GE) Model PG7121-EA CTs, each with a rated capacity of 901 MMBtu/hr when firing on natural gas, 967 MMBtu/hr when firing on standby fuel oil, and with a base load of 102-MW each. One unit is a GE Model PG7241S-FA CT with a rated capacity of 1624 MMBtu/hr when firing on natural gas, 1820 MMBtu/hr when firing on standby fuel oil, and with a base load of 198-MW. Additional equipment consists of two natural gas pipeline heaters, each rated at 9.948 MMBtu/hr, one 2.59 MMBtu/hr diesel driven emergency fire pump, and two-1,000,000 gallon distillate fuel oil storage tanks.

The facility was originally permitted under a state major permit issued on January 14, 2002. The permit was amended on March 11, 2003, to include the second natural gas fuel pipeline heater. On May 11, 2007, the permit was amended to allow operation of each CT at 60-100% of its base load (from the original 90-100% of base load). To provide consistency between the Minor NSR and Title V permit, the permit was again amended on October 27, 2009, and most recently amended on June 16, 2015.

The turbines commenced operation in 2003 and all turbines are subject to the requirements of 40 CFR 60, Subpart GG. The emergency diesel fire pump (EU 6) is subject to 40 CFR 63, Subpart ZZZZ.

This source is located in an attainment area for all pollutants and is a minor source under Prevention of Significant Deterioration (PSD) regulations. The facility is a Title V major source of carbon monoxide (CO) and nitrogen oxides (NO_X) pollutants. The facility submitted a Title V application dated June 27, 2014, which was received by the DEQ on June 30, 2014. Supplemental information dated November 10, 2014 was received by the DEQ on November 12, 2014. The facility is currently operating under a permit application shield.

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. On July 28, 2015, the U.S. Court of Appeals for the D.C. Circuit issued its opinion on the remaining issues raised with respect to CSAPR. The court decision keeps CSAPR in place. EPA is currently reviewing the decision and will determine appropriate further course of action once their review is complete.

The Acid Rain Renewal Application, dated June 25, 2014, was received by the DEQ on June 30, 2014. The CAIR Renewal Application, dated June 25, 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.

COMPLIANCE STATUS

The facility normally undergoes a full compliance evaluation (FCE) biennially. The most recent FCE, including a site visit, was conducted on May 6, 2014. In addition, all reports, notifications, and other data as required by permit conditions or regulations, which are submitted to the DEQ, are evaluated for compliance. Based on these compliance evaluations, the facility has not been found to be in violation of any state or federal applicable requirements at this time.

EMISSION UNIT AND CONTROL DEVICE IDENTIFICATION

The emissions units at this facility consist of the following:

Emission Unit ID	Stack ID	Emission Unit Description	Size/Rated Capacity	Pollution Control Device (PCD) Description	PCD ID[1]	Pollutant Controlled	Applicable Permit Date[2]
Fuel Burning Equipment							
EU 1 thru EU 4	S-1 thru S-4	Each CT is a GE Model PG 7121 (EA) simple cycle combustion turbine. Constructed in 2002	901 MMBtu/hr on natural gas each[3] 967 MMBtu/hr on distillate fuel oil, each[3]	When firing natural gas – dry low NOx burners, each unit, When firing distillate fuel oil – water injection, each unit	CD-1 CD-2	NOx	Minor NSR 10/27/09, as amended 2/26/10 and 6/16/15
EU 5	S-5	The CT is a GE Model PG 7241S (FA) simple cycle combustion turbine. Constructed in 2002	1,624 MMBtu/hr on natural gas[3] 1,820 MMBtu/hr on distillate fuel oil[3]	When firing natural gas – dry low NOx burners, each unit, When firing distillate fuel oil	CD-1 CD-2	NOx	Minor NSR 10/27/09, as amended 2/26/10 and 6/16/15

Emission Unit ID	Stack ID	Emission Unit Description	Size/Rated Capacity	Pollution Control Device (PCD) Description	PCD ID[1]	Pollutant Controlled	Applicable Permit Date[2]
				– water injection, each unit			
EU 6	S-6 a,b	Natural gas pipeline heater. Constructed in 2002	9.948 MMBtu/hr	None	N/A	N/A	Minor NSR 10/27/09, as amended 2/26/10 and 6/16/15
EU 7	S-7 a,b	Natural gas pipeline heater. Constructed in 2002	9.948 MMBtu/hr	None	N/A	N/A	Minor NSR 10/27/09, as amended 2/26/10 and 6/16/15
EU 8	S-8	Emergency diesel fire pump Constructed in 2003	2.59 MMBtu/hr	none	N/A	N/A	Minor NSR 10/27/09, as amended 2/26/10 and 6/16/15

Emission Unit ID	Stack ID	Emission Unit Description	Size/Rated Capacity	Pollution Control Device (PCD) Description	PCD ID[1]	Pollutant Controlled	Applicable Permit Date[2]
TNK 1 TNK 2	S-9 S-10	No 2 distillate fuel oil storage tanks Constructed in 2002	1,000,000 gallons, each	none	N/A	N/A	Minor NSR 10/27/09, as amended 2/26/10 and 6/16/15

[1] CD-1 = dry low NOx technology
CD-2 = water injection

[2] Original Minor NSR permit was issued on 1/14/02, amended on 3/11/03 and 5/11/07; reissued on 10/27/09, amended on 2/26/10 and 6/16/15.

[3] When operated at 100 percent base load at atmospheric conditions – temperature of 59 °F , relative humidity of 60 percent and a pressure of 14.7 psia.

EMISSIONS INVENTORY

Annual emissions summarized in the following table are derived from the 2014 CEDS emission report. A copy of the report is attached as Attachment A.

2014 Actual Emissions

2014 Criteria Pollutant Emission in Tons/Year					
Emission Unit	**VOC**	**CO**	**SO_2**	**PM_{10}**	**NO_X**
EU 1	0.48	6.12	0.9	1.97	7.74
EU 2	0.42	4.92	0.92	1.71	7.4
EU 3	0.45	2.59	1.02	1.81	8.02
EU 4	0.46	3.87	0.88	1.87	8.54
EU 5	1.32	14.25	2.04	6.97	26.54
EU 6	0.036	0.067	0.100	0.018	0.074
EU 7	0.045	0.086	0.128	0.023	0.094
EU 8	0.000	0.010	0.006	0.001	0.039
TNK 1	0.132	-	-	-	-
TNK 2	0.132	-	-	-	-
Total:	**3.47**	**31.91**	**5.99**	**14.36**	**58.45**

No significant Hazardous Air Pollutant Emissions.

EMISSION UNIT APPLICABLE REQUIREMENTS

Fuel Burning Equipment Requirements – Combustion Turbines (EU 1 – EU 5)

Limitations

Minor NSR permit: The following limitations are state BACT requirements from the state major permit issued on October 27, 2009, as amended February 26, 2010 and June 16, 2015.

Title V Permit
Condition #

1: Requires all combustion turbines (CT), EU 1 – EU 5, to control NOx emissions by utilizing a dry low NOx combustor when firing on natural gas, and water injection when firing on #2 fuel oil.
(Condition 1 of 10/27/09 Permit, as amended 2/26/10 and 6/16/15)

29 & 37: Requires natural gas pipeline heaters (EU 6 & EU 7) and the emergency diesel

fire pump (EU 8) to control NOx emissions by the use of good operating techniques.
(Condition 2 of 10/27/09 Permit, as amended 2/26/10 and 6/16/15)

2, 30 & 38: Requires SO_2 emissions from all fuel burning equipment (EU 1 – EU 8) to be controlled by the use of low sulfur fuels.
(Condition 3 of 10/27/09 Permit, as amended 2/26/10 and 6/16/15)

3, 31 & 39: Requires PM_{10} emissions from all fuel burning equipment, (EU 1 – EU 8) to be controlled by the use of clean burning fuels and good combustion operating practices.
(Condition 4 of 10/27/09 Permit, as amended 2/26/10 and 6/16/15)

4, 32 & 40: Requires VOC and CO emissions from all fuel burning equipment, (EU 1 – EU 8) to be controlled by the use of good combustion practices.
(Condition 5 of 10/27/09 Permit, as amended 2/26/10 and 6/16/15)

9: For the CTs, EU 1- EU 5, defines the two types of fuel switching events, and limits the excess NOx emissions to no more than two one-hour averaging periods for any fuel switching event.
(Condition 16 of 10/27/09 Permit, as amended 2/26/10 and 6/16/15)

10: Sets short-term emission limits for PM_{10}, NOx, and CO for combustion turbines (EU 1 – EU 5) when firing on natural gas, except during start-up, shutdown, fuel switching, and re-tuning. The short-term emissions for distillate fuel oil are applied during fuel switching operations; and any emissions above these limits are considered excess emissions. The emission rates are based on manufacturer's data provided with the Title V application.
(Condition 17 of 10/27/09 Permit, as amended 2/26/10 and 6/16/15)

11: Sets short-term emission limits for PM_{10}, NOx, and CO for combustion turbines (EU 1 – EU 5) when firing on No. 2 distillate fuel oil, except during start-up, shut-down, fuel switching, and re-tuning. The emission rates are based on manufacturer's data provided with the Title V application. As notated, the allowable NOx emission limit may vary depending on the fuel bound nitrogen content. NOx emissions concentrations that do not exceed the limits specified in Subpart GG are allowed during startup/shutdown.
(Condition 18 of 10/27/09 Permit, as amended 2/26/10 and 6/16/15)

12: Defines startup and shutdown conditions.
(Condition 19 of 10/27/09 Permit, as amended 2/26/10 and 6/16/15)

13: Sets annual emission limits for CO and NOx for CTs (EU 1 – EU 5).
(Condition 20 of 10/27/09 Permit, as amended 2/26/10 and 6/16/15)

14: Sets visible emission limit for CTs (EU 1 – EU 5).
(Condition 22 of 10/27/09 Permit, as amended 2/26/10 and 6/16/15)

49: Limits the type of fuel oil stored in the fixed roof storage tanks (TNK 1 & TNK 2.
(Condition 13 of 10/27/09 Permit, as amended 2/26/10 and 6/16/15)

50: Sets facility-wide emission limits for NOx, to ensure that PSD threshold limits are not exceeded.
(Condition 21 of 10/27/09 Permit, as amended 2/26/10 and 6/16/15)

The following are operational and fuel specific limits to ensure that the facility demonstrates compliance with the short-term and annual emissions, and Subpart GG requirements.

5: Limits the operating hours and base load operating percentage for the CTs, EU 1 – EU 5, when firing on natural gas and fuel oil.
(Condition 6 of 10/27/09 Permit, as amended 2/26/10 and 6/16/15).

41: Limits the hours of operation for the emergency diesel fire pump, EU 8.
(Condition 7 of 10/27/09 Permit).

33: Limits the combined natural gas throughput of the two pipeline heaters (EU 6 & EU 7) to 33 x 10^6 cubic feet per year.
(Condition 8 of 10/27/09 Permit, as amended 2/26/10 and 6/16/15).

6, 34 & 42: Specifies the approved fuels for the fuel burning equipment (EU 1 - EU 5).
(Condition 9 of 10/27/09 Permit, as amended 2/26/10 and 6/16/15).

7, 35: Specifies the maximum and annual average sulfur content of the natural gas for the CTs (EU 1 – EU 5) and the pipeline heaters (EU 6 & EU 7). The maximum sulfur content of the natural gas is limited to 20 grains/100dscf (equivalent to approximately 0.068% by weight). The annual average sulfur content is limited to no more than 2 grains/100 dscf for the CTs and the pipeline heaters.
(Condition 10 of 10/27/09 Permit, as amended 2/26/10 and 6/16/15).

8 & 43: Specifies the maximum sulfur content of the fuel oil (0.05% by weight) for the CTs (EU 1 – EU 5) and 0.5% (by weight) for the emergency diesel fire pump (EU 8).
(Condition 11 of 10/27/09 Permit, as amended 2/26/10 and 6/16/15)

15: Requires the CTs (EU 1 – EU 5) to be operated in compliance with 40 CFR 60, Subpart GG unless the federal operating permit is more restrictive.
(Condition 14 of 10/27/09 Permit, as amended 2/26/10 and 6/16/15)

26.a: Limits the duration of each CT re-tuning event to no more than twelve hours in a twenty-four period.
(Condition 36 of 10/27/09 Permit, as amended 2/26/10 and 6/16/15)

26.b: Allows NOx emissions concentrations that do not exceed the standards of Subpart GG during each CT re-tuning event.
(Condition 36 of 10/27/09 Permit, as amended 2/26/10 and 6/16/15)

27.b: Allows NOx emissions concentrations that do not exceed the standards of Subpart GG during a malfunction.
(Condition 37 of 10/27/09 Permit, as amended 2/26/10 and 6/16/15)

The following is a Virginia Administrative Code requirement that has been determined to be applicable to the facility.

36: Limits visible emissions from each pipeline heater (EU 6 & EU 7) to 20 percent opacity except for one six-minute period in any hour in which visible emissions may not exceed 30 percent opacity
(9 VAC 5-80-490 and 9 VAC 5-50-80)

Certain provisions of 40 CFR Part 63, Subpart ZZZZ (National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines) are applicable to the emergency diesel fire pump (EU 8). The unit is considered an emergency engine at an 'area HAP' source; consequently the following requirements are included in the Title V Permit for this unit:

44: Requires the emergency diesel fire pump (EU 8) to be operated in compliance with 40 CFR 63, Subpart ZZZZ unless the federal operating permit is more restrictive.
(40 CFR 63 Subpart ZZZZ)

45: Requires that, in order for the diesel fire pump (EU 8) to be considered an emergency unit, operation of the pump is limited to emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year
(40 CFR §63.6640 (f))

46: Provides the work practice standards for the emergency diesel fire pump engine (EU 8) (oil & filter change, inspect/replace spark plugs, belts and hoses at specified intervals)
(40 CFR Part 63, Subpart ZZZZ, Table 2d)

47: Requires that the emergency diesel fire pump (EU 8) be operated and maintained in accordance with the manufacturer's emission-related operation and

maintenance instructions or follow own maintenance plan meeting certain requirements.
(40 CFR Part 63, Subpart ZZZZ, Table 6)

48: Requires that a non-resettable hour meter me installed on the emergency diesel fire pump, EU6
(40 CFR Part 63, Subpart ZZZZ)

Monitoring

The compliance strategy for the facility entails continuous monitoring of NOx and CO, proper operation and maintenance of the equipment, the use of low sulfur fuels, and good combustion practices.

For the combustion turbines, a continuous emissions monitoring system (CEMS) is used to monitor NOx and O_2 from all CTs (EU 1 – EU 5) and CO from CTs EU 1 – EU 4. CEMS were installed to ensure the facility remains below PSD levels for NOx and CO, and to demonstrate compliance with emission standards of NSPS Subpart GG and BACT. A CO CEMS is not required on EU 5 because of the low emission rate demonstrated by this CT model. Records of fuel type, fuel throughput, NOx CEMS data, and maintenance records, will provide assurance that the EU 5 CO limits are not exceeded.

The NOx and O_2 monitors on each CT (EU 1 – EU 5) are used in lieu of monitoring the ratio of water to fuel, in accordance with Subpart GG (40 CFR 60.334(b)).

The CTs burn primarily natural gas, with low sulfur diesel as backup. As long as they are properly maintained and operated, PM_{10} 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 PM_{10} and opacity standards.

16: Allows the Board to determine how the facility will demonstrate compliance with the NOx and CO emission limits.
(Condition 23 of 10/27/09 Permit, as amended 2/26/10 and 6/16/15)

17: Requires a NOx CEMS and O_2 monitor on all CTs, EU 1 - EU 5, and specifies minimum requirements for quality assurance of the data. The CTs are affected units under the Acid Rain Program and must meet the requirements of Part 75. NOx CEMS that meet the requirements of Part 75 may use the CEMS to meet the requirements of Subpart GG.
(Condition 24 of 10/27/09 Permit, as amended 2/26/10 and 6/16/15)

18: Requires a CO CEMS on CTs, EU 1 - EU 4; specifies the minimum requirements for quality assurance of the data; and stipulates the frequency of the cylinder gas

audits (CGA) and the relative accuracy test audits (RATA).
(Condition 25 of 10/27/09 Permit, as amended 2/26/10 and 6/16/15)

19: Requires a NOx and CO minimum data capture of 90% of each CT's operating hours.
(Condition 26 of 10/27/09 Permit, as amended 2/26/10 and 6/16/15)

20: Specifies data alternatives in the event of a NOx CEMS failure.
Although Subpart GG allows missing data to be recorded as monitor down time with no data substitution, DEQ requires missing data substitution to ensure that the annual emissions do not trigger PSD.
(Condition 27 of 10/27/09 Permit, as amended 2/26/10 and 6/16/15)

21: Specifies a data alternative in the event of a CO CEMS failure.
DEQ requires missing data substitution to ensure that the annual emissions do not trigger PSD.
(Condition 28 of 10/27/09 Permit, as amended 2/26/10 and 6/16/15)

22: Requires installation of a continuous monitoring system (CMS) to measure and record the hourly flow rate of fuel combusted by each CT (EU 1 – EU 5)
(Condition 29 of 10/27/09 Permit, as amended 2/26/10 and 6/16/15)

23: Requires the sulfur content to be monitored when natural gas is fired in each CT, EU 1 - EU 5, in accordance with the EPA approved custom fuel monitoring schedule. In the letter to EPA dated February 27, 2003, ODEC requested a custom fuel monitoring schedule for natural gas sulfur content under the NSPS Subpart GG. On March 28, 2003, EPA approved the proposal to decrease the monitoring over time (see EPA letter 3/28/03). In the letter dated June 23, 2004, ODEC requested an alternative schedule. ODEC received EPA approval on July 9, 2004, to allow sampling and testing to be performed during periods when the turbines are actually operating (see EPA letter 7/9/04)
(Condition 30 of 10/27/09 Permit, as amended 2/26/10 and 6/16/15)

24: Requires testing for the nitrogen and sulfur content prior to combustion in the CTs, EU 1 – EU 5, when No. 2 distillate fuel is transferred to the storage tanks.
(Condition 31 of 10/27/09 Permit, as amended 2/26/10 and 6/16/15)

25: Requires certification of quantity and sulfur content for each fuel oil delivery; includes allowance for fuel sampling and analysis independent of that used for certification to determine fuel oil sulfur content.
(Condition 12 of 10/27/09 Permit, as amended 2/26/10 and 6/16/15)

51: Specifies maintenance and operating procedures applicable to process and air pollution control equipment

(Condition 39 of 10/27/09 Permit, as amended 2/26/10 and 6/16/15)

40 CFR 64, Compliance Assurance Monitoring (CAM) -
ODEC employs a CEMS to measure NOx emissions from the CTs (EU 1 – EU 5) to ensure that the facility remains a minor source under PSD. According to 40 CFR 64.2(b)(1)(vi), emission limitations or standards for which a part 70 (Title V) permit specifies a continuous compliance determination method are exempt from Compliance Assurance Monitoring (CAM) (40 CFR 64) requirements. Also, the CTs are not subject to CAM for any other pollutants as there are no add-on control devices for any other pollutants. Therefore, the CTs are not subject to CAM.

No other emissions units at the facility utilize control devices. Therefore, CAM is not applicable to any emissions unit at ODEC.

Recordkeeping

The permit includes requirements for recordkeeping necessary to demonstrate compliance with the permit. In addition, NOx emissions during each CT re-tuning event or malfunction must be recorded and included in the total annual emissions.

52.h: Requires recordkeeping for scheduled and unscheduled maintenance, operator training, and equipment procedures for equipment EU 1 – EU 8.
(Condition 32 of 10/27/09 Permit, as amended 2/26/10 and 6/16/15)

52.a-f: Requires recordkeeping of emissions data, emissions calculations, CEMS calibration information, results of testing, and operating data including fuel records, fuel certifications, fuel consumption, and operating hours.
(9 VAC 5-80-490 F and Condition 34 of 10/27/09 Permit, as amended 2/26/10 and 6/16/15)

26.e: Requires NOx emissions to be recorded during each CT re-tuning event and included in the total annual emissions.
(Condition 36 of 10/27/09 Permit, as amended 2/26/10 and 6/16/15)

27.e: Requires NOx emissions to be recorded during a malfunction and included in the total annual emissions.
(Condition 37 of 10/27/09 Permit, as amended 2/26/10 and 6/16/15)

Testing

There are no applicable initial compliance determinations required. In accordance with the permit dated March 11, 2003, an initial performance test for NOx and CO, and a visible emissions evaluation (VEE) was performed on each CT (EU 1 - EU 5) when firing on distillate fuel oil and when firing on natural gas. The testing was completed in August of 2003 and the CTs demonstrated compliance with the hourly and visible emissions limits. It should also be noted that since the NOx CEMS are subject to 40 CFR Part 75 (Acid Rain) regulation, they are required to undergo routine quality assurance assessments such as quarterly linearity testing and annual relative accuracy test audits using EPA-approved test methods.

53: The facility shall be modified to allow emissions testing and monitoring upon reasonable notice at any time if requested by DEQ.
(Condition 15 of 10/27/09 Permit, as amended 2/26/10 and 6/16/15)

54: If testing other than the monitoring specified in the permit is conducted, appropriate methods in accordance with procedures approved by DEQ are to be used
(9 VAC 5-80-490 E)

Reporting

27: Requires notification, within four daytime business hours, of malfunction of the affected facility or related air pollution control equipment. The emission units that have continuous monitors subject to 9 VAC 5-40-50 C and 9 VAC 5-50-50 C are not subject to the two week written statement. Notification is required when the malfunction is corrected.
(Condition 37 of 10/27/09 Permit, as amended 2/26/10 and 6/16/15)

26.c: Requires notification, with applicable information, twenty-four hours prior to each CT re-tuning event.
(Condition 36 of 10/27/09 Permit, as amended 2/26/10 and 6/16/15)

26.d: Requires submittal of a written report detailing each CT re-tuning event within fourteen business days of event.
(Condition 36 of 10/27/09 Permit, as amended 2/26/10 and 6/16/15)

26.f: Requires identification of each CT re-tuning event on the Data Acquisition Report.
(Condition 36 of 10/27/09 Permit, as amended 2/26/10 and 6/16/15)

27.c: Requires notification, with applicable information, within four daytime business hours of discovering malfunction.
(Condition 37 of 10/27/09 Permit, as amended 2/26/10 and 6/16/15)

27.d: Requires quarterly submittal of a written report detailing each CT malfunction.
(Condition 37 of 10/27/09 Permit, as amended 2/26/10 and 6/16/15)

27.f: Requires identification of each malfunction on the Data Acquisition Report.

(Condition 37 of 10/27/09 Permit, as amended 2/26/10 and 6/16/15)

28: Requires calendar quarter excess emission reports, by month, for NOx and CO, and any CEMS adjustments, repairs, or inoperation, including reporting of no excess emissions or CEMS deviations.
(Condition 33 of 10/27/09 Permit, as amended 2/26/10 and 6/16/15)

55: Provides addresses for reports submitted to DEQ and to EPA
(9 VAC 5-80-490 B & C)

56: Requires notification, with applicable information, twenty-four hours prior to necessary scheduled control equipment maintenance.
(Condition 33 of 10/27/09 Permit, as amended 2/26/10 and 6/16/15)

57: Specifies requirements for certification of documents submitted to DEQ
(Condition 37 of 10/27/09 Permit, as amended 2/26/10 and 6/16/15)

Streamlined Requirements

The combustion turbines have the following applicable requirements established in NSPS Subpart GG, which is included in 9 VAC 5-50-410 by reference:

§ 60.332(a)(2): Standard for Nitrogen Oxides
where:

$$STD = 0.0150\ \frac{(14.4)}{Y} + F$$

STD = Allowable NO_x emissions (percent by volume at 15 percent oxygen and on a dry basis).
Y = Manufacturer's rated heat rate at manufacturer's rated peak load (kilojoules per watt hour), or actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour.
F = NO_x emission allowance for fuel-bound nitrogen as defined in § 60.332 (a)(3)

The allowable NO_x emission limits for each of the turbines contained in the minor NSR permit are more stringent than the limits established by NSPS Subpart GG. Therefore, only the limits from minor NSR permit have been included in the Title V permit. However, due to the difference in averaging periods and the treatment of startup and shutdowns periods, compliance with the limit under NSPS Subpart GG must be reported and documented apart from compliance with the BACT limits contained in the minor NSR permit.

§ 60.333: Standard for sulfur dioxide:

SO_2: 0.015 percent by volume, dry basis, at 15% O_2, OR, fuel sulfur content: 0.8 percent by weight.

The fuel sulfur content requirements for natural gas and fuel oil in the minor NSR permit (Conditions 10 & 11) are more stringent than the standard contained in NSPS Subpart GG. Therefore, only the limit from the minor NSR permit has been included in the Title V permit. Demonstrating compliance with the sulfur content limits in the minor NSR permit will ensure compliance with the NSPS limits.

GENERAL CONDITIONS

The permit contains general conditions required by 40 CFR Part 70 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.

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 Permit (FOP)).

The Phase II permit is incorporated into the permit. The units were not eligible for SO_2 allowances because the facility commenced operation after all allowances had been assigned. The facility is not subject to the NO_x requirements because it does not operate coal-fired units. The application for renewal of Article 3 FOP, dated June 25, 2014, was received by the DEQ on June 30, 2014. Upon renewal, the Article 3 FOP will have an expiration date of December 31, 2019.

A copy of the Title IV Acid Rain Permit application is provided as Attachment A to the Permit, and Attachment C 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 108 through 117). 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 identified by the applicant.

FUTURE APPLICABLE REQUIREMENTS

None identified by the applicant or DEQ.

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 CO2e 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 minor NSR permit for the Louisa Generation Facility 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:

<u>40 CFR 63, Subpart UUUUU</u> – *National Emission Standards for Hazardous Air Pollutants for Coal- and Oil-Fired Electric Utility Steam Generating Units* does not apply to gas-fired, non-steam turbines such as those operated by ODEC-Louisa (EU 1 - EU 5).

<u>40 CFR 63, Subpart JJJJJJ</u> – *National Emission Standards for Hazardous Air Pollutants for*

Industrial, Commercial and Institutional Boilers at Area Sources does not apply to process heaters (such as ODEC-Louisa's gas-fired pipeline gas heaters EU 6 and EU 7), as they are excluded from the definition of boiler in 40 CFR 63.11237. Also, gas-fired boilers are not subject to Subpart JJJJJJ.

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

40 CFR 60, Subpart Kb – *Standards of Performance for Volatile Organic Liquid Storage Vessels* is no longer applicable to storage vessels that store liquids with a vapor pressure less than 3.5 kilopascals (0.5 psia). Storage tanks TNK 1 and TNK 2 are permitted for storage of No. 2 distillate fuel oil only which has vapor pressure less than 0.5 psia.

40 CFR 60, Subpart Dc - *Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units* is not applicable to the two natural gas pipeline heaters, EU 6 and EU 7 because the heaters are less than 10 MMBtu/hr.

40 CFR 60, Subpart KKKK – *Standards of Performance for Stationary Combustion Turbines* applies to stationary combustion turbines that commenced construction after February 18, 2005.

40 CFR 63, Subpart YYYY – *National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines* applies to stationary combustion turbines located at major sources of HAP emissions. ODEC-Louisa is not a major source of HAP.

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.

INSIGNIFICANT EMISSION UNITS

The facility identified several "named insignificant activities" in the Introduction section of the TV permit application. "Named insignificant activities" are not required to be listed in the Title V permit application. 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.

Insignificant emission units include the following:

Emission Unit No.	Emission Unit Description	Citation 9 VAC 5-80-720 A, B, or C	Pollutant(s) Emitted (if applicable to 9 VAC 5-80-720 B)	Rated Capacity (if applicable to 9 VAC 5-80-720 C)
IS-1	Fuel Oil Tank for Emergency Diesel Fire Pump	9 VAC 5-80-720 B	VOC < 1 tpy	280 gallons
IS-2	CT Units 1-5 Turbine Lube Oil System Reservoirs	9 VAC 5-80-720 B	VOC < 1 tpy	4 @ 2,500 gallons 1 @ 6,200 gallons
IS-3	CT Units 1-5 Propylene Glycol Coolant System Reservoirs	9 VAC 5-80-720 B	VOC < 1 tpy	4 @ 2,500 gallons 1 @ 3,000 gallons
IS-4	CT Units 1-5 False Start Drain Tanks	9 VAC 5-80-720 B	VOC < 1 tpy	4 @ 400 gallons 1 @ 500 gallons
IS-5	Oil Water Separators	9 VAC 5-80-720 B	VOC < 1 tpy	1 @ 1,000 gallons 1 @ 6000 gallons

[1]The citation criteria for insignificant activities are as follows:
9 VAC 5-80-720 A - Listed Insignificant Activity, Not Included in Permit Application
9 VAC 5-80-720 B - Insignificant due to emission levels
9 VAC 5-80-720 C - Insignificant due to size or production rate

CONFIDENTIAL INFORMATION

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

OTHER CONSIDERATIONS

USEPA Acid Rain Program:
Designated Representative – David N. Smith on April 20, 2001
Alternate Representative – Alvin D. Vaughan on October 12, 2004

USEPA CSAPR Program:
Designated Representative – David N. Smith on December 19, 2006
Alternate Representative – Alvin D. Vaughan on December 20, 2006

PUBLIC PARTICIPATION

A public notice regarding the draft permit was placed in the Central Virginian newspaper, in Fredericksburg, Virginia, on October 22, 2015. All persons on the Title V mailing list and affected states (Maryland and Washington, D.C.) were sent a copy of the public notice by either electronic mail or in letters on October 22, 2015.

The 30-day public comment period began October 22, 2015 and continued through November 23, 2015. No comments from the public were received on the draft permit.

The EPA was sent a copy of the draft permit and notified of the public notice on November 10, 2015. On December 2, 2015, EPA notified DEQ by email that its review of the proposed draft permit was complete and that EPA had no comments.

ATTACHMENTS

Attachment A	2014 Annual Emissions Update
Attachment B	Minor NSR Permit dated October 27, 2009, as amended February 26, 2010 and June 16, 2015
Attachment C	Title IV Acid Rain Permit Application

ATTACHMENT A

2014 Annual Emissions Report

Old Dominion Electric Cooperative

ODEC

Overnight Delivery

VA DEPARTMENT OF ENVIRONMENTAL QUALITY
APR 16 2015
WOODBRIDGE, VA

April 15, 2015

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

Subject: Old Dominion Electric Cooperative (ODEC) – Louisa Generation Facility (LGF) Annual Update for Calendar Year 2014 and 2014 Emission Statement Registration Number 40989

Dear Air Compliance Manager:

Enclosed are the following annual reports prepared for ODEC's LGF:

1) Annual Update for Calendar Year 2014
2) 2014 Emission Statement, which includes appropriate forms and a supplemental emissions calculations spreadsheet showing how the data in the Emissions Statement was derived (Note: the stack parameter page was not included as there have been no changes to that information)

If you have any questions, feel free to contact Mr. Dahlgren Vaughan at (804) 968-7149.

Sincerely,

D. Richard Beam

D. Richard Beam
Senior Vice President of Power Supply

Enclosures

cc: Peter F. Gallini (electronic)
David N. Smith (electronic)

Commonwealth of Virginia
Department of Environmental Quality

Annual Update for Calendar Year: 2014

Registration#: 40989
Plant Name: Old Dominion Electric Cooperative - Louisa
Physical Location: 3352 Klockner Rd
Mailing Address: 4201 Dominion Boulevard
Glen Allen, VA 23060

Region: NVRO
County: 109 Louisa County
Plant ID: 00050
Contact Person: Smith, David
Telephone: (804)968-4045
Employees: 8
Principal Product: Electricity
SIC: 4911 NAICS: 221112
Inspector: Page, Tedric
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	% Annual Thruput Mar May	% Annual Thruput Jun Aug	% Annual Thruput Sep Nov	Operating Schedule Hr Dy	Operating Schedule Dy Wk	Operating Schedule Hr Yr	% Space Heat	Stack Parameters Ht (ft)	Stack Parameters Dia (ft)	Stack Parameters Exit Temp (f)	Stack Parameters Exit Flow Rate (ACFM)	Stack Parameters Plume Ht (ft)	Stack Parameters Elevation (ft)
1	1	1	Unit 1-Simple Cycle EA CT, nat gas fired	20100201	~~299817~~ 194506	Million BTUs Fuel Input			~~1022~~ 1017		205		~~17~~ 52	~~22~~ 24	~~28~~ 8	~~35~~ 16	24	7	6872		56	18	958	1617600		250
											205 = LOW NOX BURNERS															
1	1	2	Unit 1-Simple Cycle EA CT, No.2	20100101	~~88~~ 100124	Million BTUs Fuel Input	.05		~~140~~ 139		028		~~17~~	~~22~~	~~28~~	~~35~~	24	7	6872		56	18	958	1617600		250
											028 = Steam or Water Injection															
2	2	1	Unit 2-Simple Cycle EA-CT, nat gas fired	20100201	~~198740~~ 136376	Million BTUs Fuel Input			~~1013~~ 1022		205		~~24~~ 64	~~13~~ 29	~~35~~ 5	~~28~~ 2	24	7	6872		56	18	958	1617600		250
											205 = LOW NOX BURNERS															
2	2	2	Unit 2-Simple Cycle EA-CT, No.2 fired	20100101	~~233~~ 109670	Million BTUs Fuel Input	.05		~~140~~ 139		028		~~24~~	~~13~~	~~35~~	~~28~~	24	7	6872		56	18	958	1617600		250
											028 = Steam or Water Injection															
3	3	1	Unit 3-Simple Cycle EA-CT, nat gas fired	20100201	~~188425~~ 123454	Million BTUs Fuel Input			~~1013~~ 1022		205		~~24~~ 64	~~12~~ 30	~~37~~ 6	~~27~~ 0	24	7	6872		56	18	958	1617600		250
											205 = LOW NOX BURNERS															
3	3	2	Unit 3-Simple Cycle EA-CT, No.2	20100101	~~40~~ 121960	Million BTUs Fuel Input	.05		~~140~~ 139		028		~~24~~	~~13~~	~~37~~	~~27~~	24	7	6872		56	18	958	1617600		250
											028 = Steam or Water Injection															
4	4	1	Unit 4-Simple Cycle EA-CT, nat gas fired	20100201	~~182385~~ 146071	Million BTUs Fuel Input			~~1013~~ 1018		205		~~27~~ 60	~~24~~ 28	~~31~~ 3	~~18~~ 9	24	7	6872		56	18	958	1617600		250
											205 = LOW NOX BURNERS															
4	4	2	Unit 4-Simple Cycle EA-CT, No.2	20100101	~~243~~ 122658	Million BTUs Fuel Input	.05		~~140~~ 139		028		~~27~~	~~24~~	~~31~~	~~18~~	24	7	6872		56	18	958	1617600		250
											028 = Steam or Water Injection															

Date : 12/16/2014 09:25 AM

Commonwealth of Virginia
Department of Environmental Quality

Annual Update for Calendar Year: 2014

Registration#:	40989
Plant Name:	Old Dominion Electric Cooperative - Louisa
Physical Location:	3352 Klockner Rd
Mailing Address:	4201 Dominion Boulevard Glen Allen, VA 23060

Region:	NVRO
County:	109 Louisa County
Plant ID:	00050
Contact Person:	Smith, David
Telephone:	(804)968-4045
Employees:	8
Principal Product:	Electricity
SIC:	4911 NAICS: 221112
Inspector:	Page, Tedric
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	Unit 5-Simple Cycle FA-CT, nat gas fired	20100201	~~713217~~ 1027046	Million BTUs Fuel Input			~~1013~~ 1021		205 205 = LOW NOX BURNERS		~~40~~ 26	~~45~~ 29	~~41~~ 26	~~25~~ 19	24	7	1718		90	18	1058	2579000		250
5	5	2	Unit 5-Simple Cycle FA-CT, No.2 fired	20100101	~~8599~~ 213810	Million BTUs Fuel Input	.05		~~140~~ 139		028 028 = Steam or Water Injection		~~40~~	~~45~~	41	25	24	7	1718		90	18	1058	2579000		250
6	6	1	Pipeline Heater, nat gas fired	10500106	~~.7~~ 1.1	Million Cubic Feet Burned			~~1013~~ 1020				~~26~~ 39	~~42~~ 40	~~14~~ 9	~~18~~ 12	24	7	8760		26	2	775	984		250
7	7	1	Pipeline Heater, nat gas fired	10500106	~~.8~~ 1.4	Million Cubic Feet Burned			~~1013~~ 1020				~~24~~ 16	~~39~~ 65	~~17~~ 8	~~20~~ 11	24	7	8760		25	2	775	984		250
8	8	1	Emerg Diesel Fire Pump	20300101	~~.2~~ 0.2	1000 Gallons Burned	.5		138				~~24~~ 21	~~24~~ 24	~~26~~ 27	~~28~~ 28	24	7	8760		20	.67	752	2538.47		250
9	9	1	No. 2 Fuel Oil AST (Tank 1) - Storage Capacity	40301020	1000	1000 Gallons Storage Capacity							25	25	25	25	24	7	8760						50	
9	9	2	No. 2 Fuel Oil AST (Tank 1) - Throughput	40301021	~~38~~ 2412	1000 Gallons Throughput							25	25	25	25	24	7	8760						50	
10	10	1	No. 2 Fuel Oil AST (Tank 2) - Storage Capacity	40301020	1000	1000 Gallons Storage Capacity							25	25	25	25	24	7	8760						50	

Commonwealth of Virginia
Department of Environmental Quality

Annual Update for Calendar Year: 2014

Registration#: 40989
Plant Name: Old Dominion Electric Cooperative - Louisa
Physical Location: 3352 Klockner Rd
Mailing Address: 4201 Dominion Boulevard
Glen Allen, VA 23060

Region: NVRO
County: 109 Louisa County
Plant ID: 00050
Contact Person: Smith, David
Telephone: (804)968-4046
Employees: 8
Principal Product: Electricity
SIC: 4911 NAICS: 221112
Inspector: Page, Tedric
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	% Annual Thruput: Mar May	% Annual Thruput: Jun Aug	% Annual Thruput: Sep Nov	Operating Schedule: Hr Dy	Operating Schedule: Dy Wk	Operating Schedule: Hr Yr	% Space Heat	Stack Parameters: Ht (ft)	Stack Parameters: Dia (ft)	Stack Parameters: Exit Temp (f)	Stack Parameters: Exit Flow Rate (ACFM)	Stack Parameters: Plume Ht (ft)	Stack Parameters: Elevation (ft)
10	10	2	No. 2 Fuel Oil AST (Tank 2) - Throughput	40301021	36 2412	1000 Gallons Throughput							25	25	25	25	24	7	8760						50	

Date : 12/16/2014 09:26 AM

Commonwealth of Virginia
Department of Environmental Quality

Annual Update for Calendar Year: 2014

Registration#: 40989
Plant Name: Old Dominion Electric Cooperative - Louisa
Physical Location: 3352 Klockner Rd
Mailing Address: 4201 Dominion Boulevard
Glen Allen, VA 23060

Region: NVRO
County: 109 Louisa County
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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)

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) D. Richard Beam

Title Senior Vice President - Power Supply

Signature D. Richard Beam Date 4/15/15

DEQ

VIRGINIA DEPARTMENT OF
ENVIRONMENTAL QUALITY

2014 EMISSION STATEMENT

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

FACILITY NAME	REGISTRATION #	CONTACT PERSON	
OLD DOMINION ELECTRIC COOPERATIVE LOUISA	40989	DAVID SMITH	
LOCATION ADDRESS 3352 Klockner Road Gordonsville VA 22942		**JURISDICTION** Louisa County	
MAILING ADDRESS 4201 Dominion Boulevard	**MAILING CITY AND STATE** Glen Allen, VA	**ZIPCODE** 23060	
OWNER NAME Old Dominion Electric Cooperative	**TELEPHONE NUMBER** (804) 968-4045	**PRIMARY NAICS CODE** 221112	For Agency Use Only T5

***FACILITY TOTALS** (Sum emissions from attached pages)*

	ANNUAL		OZONE SEASON
TOTAL VOC EMISSIONS FOR 2014	3.21	TONS/YR	69.4 LBS/DAY
TOTAL NOx EMISSIONS FOR 2014	58.45	TONS/YR	656.1 LBS/DAY
TOTAL SO2 EMISSIONS FOR 2014	5.99	TONS/YR	NA
TOTAL PM10 EMISSIONS FOR 2014	14.37	TONS/YR	NA
TOTAL PB EMISSIONS FOR 2014		TONS/YR	NA
TOTAL TRS EMISSIONS FOR 2014	NA	TONS/YR	NA
TOTAL TNMOC EMISSIONS FOR 2014 (landfills only)	NA	TONS/YR	NA
TOTAL non-VOC/non-PM HAP EMISSIONS FOR 2014		TONS/YR	NA
TOTAL CO EMISSIONS FOR 2014	31.91	TONS/YR	NA
TOTAL PM2.5 EMISSIONS FOR 2014		TONS/YR	NA
TOTAL NH3 EMISSIONS FOR 2014	NA	TONS/YR	NA

PLEASE ATTACH "ANNUAL UPDATE" FORM.

PLEASE ATTACH "EMISSION STATEMENT CERTIFICATION" 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.

SIGNATURE: D. Richard Beam **DATE:** 4/15/15

PRINTED NAME: D. Richard Beam

TITLE: Senior Vice President - Power Supply

COMPANY: Old Dominion Electric Cooperative

REGISTRATION NUMBER: 40989

TELEPHONE NUMBER: (804) 968-4007

2014 EMISSIONS CALCULATIONS
OPTION I: EMISSION FACTOR METHOD

REGISTRATION # 40989 *STACK NO:* 1 *POINT NO.:* 1 *SEGMENT NO.:* 1 *SCC NO.:* 20100201

		ANNUAL		PEAK OZONE SEASON (JUNE, JULY, AUGUST)	
THRUPUT (with units)		194506 MMBtu		21366 MMBtu	
NO. OPERATING DAYS		32 days		5 days	
2012 EMISSION STATEMENT		6.2 hours		4.6 hours	
DAILY THRUPUT (with units) = Thruput / days		NA		4273.2 MMBtu/day	
VOC EMISSION FACTOR (with units) = EF		2.2 lbs/hr		2.2 lbs/hr	
Emission Factor Source[1]	Control Efficiency Basis[2]	O*		O*	
VOC CONTROL DEVICE CODE[3]					
Avg. VOC CONTROL EFFICIENCY[4] = CE		%		%	
VOC EMISSIONS[5]		0.22 tons VOC per yr		10.1 lbs VOC per day	
NOx EMISSION FACTOR (with units) = EF					
Emission Factor Source[1]	Control Efficiency Basis[2]	CEMS**		CEMS**	
NOx CONTROL DEVICE CODE[3]		205		205	
Avg. NOx CONTROL EFFICIENCY[4] = CE		%		%	
NOx EMISSIONS		2.54 tons NOx per yr		80.4 lbs NOx per day	
SO2 EMISSION FACTOR (with units) = EF					
Emission Factor Source[1]	Control Efficiency Basis[2]	O**			
FUEL PARAMETER (% ash or % sulfur) = FP		%		%	
SO2 CONTROL DEVICE CODE[3]					
Avg. SO2 CONTROL EFFICIENCY[4] = CE		%		%	
SO2 EMISSIONS[5]		0.06 tons SO2 per yr		lbs SO2 per day	
PM10 EMISSION FACTOR (with units) = EF		10 lbs/hr			
Emission Factor Source[1]	Control Efficiency Basis[2]	O*			
FUEL PARAMETER (% ash or % sulfur) = FP		%		%	
PM10 CONTROL DEVICE CODE[3]					
Avg. PM10 CONTROL EFFICIENCY[4] = CE		%		%	
PM10 EMISSIONS[5]		0.98 tons PM10 per yr		lbs PM10 per day	
PB EMISSION FACTOR (with units) = EF					
Emission Factor Source[1]	Control Efficiency Basis[2]				
PB CONTROL DEVICE CODE[3]					
Avg. PB CONTROL EFFICIENCY[4] = CE		%		%	
PB EMISSIONS[5]		tons PB per yr		lbs PB per day	

*Emission rates and factors used are from the permit application

**CEMS data for NOx and CO are calculated based upon the permit requirements and data substitution. SO2 emissions are calculated using Part 75, Appendix D monitoring requirements, and data substitution.

1. AP-42; CEMS; ST = Stack Test; F = Federal factor (EPA standard factor); O = Other (describe on separate sheet; use subject to DEQ approval)
2. A = Tested (by EPA reference method); B = Tested (other); C = Meterall Balance; D = Design; O = Other (describe on separate sheet)
3. See 3-digit control device codes listed in appendix.
4. Note control efficiency will be zero if there is no control device OR the emission factor accounts for controls (i.e. EF is identified to be "with controls")
5. Annual Emissions = ANNUAL THRUPUT x EF x FP x (1/2000) x (100-CE)/100; Ozone Emissions = DAILY THRUPUT x EF x FP x (100-CE)/100

2014 EMISSIONS CALCULATIONS
OPTION I: EMISSION FACTOR METHOD

REGISTRATION # 40989 *STACK NO:* 1 *POINT NO.:* 1 *SEGMENT NO.:* 1 *SCC NO.:* 20100201

		ANNUAL		PEAK OZONE SEASON (JUNE, JULY, AUGUST)	
THRUPUT (with units)		194506 MMBtu			
NO. OPERATING DAYS		32 days		days	
NO. OPERATING HOURS PER DAY		6.2 hours		hours	
DAILY THRUPUT (with units) = Thruput / days		NA			
TRS EMISSION FACTOR (with units) = EF		NA			
Emission Factor Source[1]	Control Efficiency Basis[2]				
TRS CONTROL DEVICE CODE[3]					
Avg. TRS CONTROL EFFICIENCY[4] = CE		%		%	
TRS EMISSIONS[5]		tons TRS per yr		lbs per day	
TNMOC EMISSION FACTOR (with units) = EF		NA			
Emission Factor Source[1]	Control Efficiency Basis[2]				
TNMOC CONTROL DEVICE CODE[3]					
Avg. TNMOC CONTROL EFFICIENCY[4] = CE		%		%	
TNMOC EMISSIONS[5]		tons TNMOC per yr		lbs per day	
CO EMISSION FACTOR (with units) = EF					
Emission Factor Source[1]	Control Efficiency Basis[2]	CEMS**			
CO CONTROL DEVICE CODE[3]					
Avg. CO CONTROL EFFICIENCY[4] = CE		%		%	
CO EMISSIONS[5]		5.23 tons CO per yr		lbs per day	
PM2.5 EMISSION FACTOR (with units) = EF					
Emission Factor Source[1]	Control Efficiency Basis[2]				
FUEL PARAMETER (% ash or % sulfur) = FP		%		%	
PM2.5 CONTROL DEVICE CODE[3]					
Avg. PM2.5 CONTROL EFFICIENCY[4] = CE		%		%	
PM2.5 EMISSIONS[5]		tons PM2.5 per yr		lbs per day	
NH3 EMISSION FACTOR (with units) = EF		NA			
Emission Factor Source[1]	Control Efficiency Basis[2]				
NH3 CONTROL DEVICE CODE[3]					
Avg. NH3 CONTROL EFFICIENCY[4] = CE		%		%	
NH3 EMISSIONS[5]		tons NH3 per yr		lbs per day	

*Emission rates and factors used are from the permit application

**CEMS data for NOx and CO are calculated based upon the permit requirements and data substitution. SO2 emissions are calculated using Part 75, Appendix D monitoring requirements, and data substitution.

1. AP-42; CEMS; ST = Stack Test; F = Federal factor (EPA standard factor); O = Other (describe on separate sheet; use subject to DEQ approval)
2. A = Tested (by EPA reference method); B = Tested (other); C = Meterail Balance; D = Design; O = Other (describe on separate sheet)
3. See 3-digit control device codes listed in appendix.
4. Note control efficiency will be zero if there is no control device OR the emission factor accounts for controls (i.e. EF is identified to be "with controls")
5. Annual Emissions = ANNUAL THRUPUT x EF x FP x (1/2000) x (100-CE)/100; Ozone Emissions = DAILY THRUPUT x EF x FP x (100-CE)/100

2014 EMISSIONS CALCULATIONS
OPTION I: EMISSION FACTOR METHOD

REGISTRATION # 40989 *STACK NO:* 1 *POINT NO.:* 1 *SEGMENT NO.:* 2 *SCC NO.:* 20100101

		ANNUAL		PEAK OZONE SEASON (JUNE, JULY, AUGUST)	
THRUPUT (with units)		100124 MMBtu		0 MMBtu	
NO. OPERATING DAYS		13 days		0 days	
NO. OPERATING HOURS PER DAY		7.3 hours		0 hours	
DAILY THRUPUT (with units) = Thruput / days		NA		0 MMBtu/day	
VOC EMISSION FACTOR (with units) = EF		5.5 lbs/hr		5.5 lbs/hr	
Emission Factor Source[1]	Control Efficiency Basis[2]	O*		O*	
VOC CONTROL DEVICE CODE[3]					
Avg. VOC CONTROL EFFICIENCY[4] = CE		%		%	
VOC EMISSIONS[5]		0.26 tons VOC per yr		0.0 lbs VOC per day	
NOx EMISSION FACTOR (with units) = EF					
Emission Factor Source[1]	Control Efficiency Basis[2]	CEMS**		CEMS**	
NOx CONTROL DEVICE CODE[3]		028		028	
Avg. NOx CONTROL EFFICIENCY[4] = CE		%		%	
NOx EMISSIONS		5.20 tons NOx per yr		0.0 lbs NOx per day	
SO2 EMISSION FACTOR (with units) = EF					
Emission Factor Source[1]	Control Efficiency Basis[2]	O**			
FUEL PARAMETER (% ash or % sulfur) = FP		%		%	
SO2 CONTROL DEVICE CODE[3]					
Avg. SO2 CONTROL EFFICIENCY[4] = CE		%		%	
SO2 EMISSIONS[5]		0.84 tons SO2 per yr		lbs SO2 per day	
PM10 EMISSION FACTOR (with units) = EF		21 lbs/hr			
Emission Factor Source[1]	Control Efficiency Basis[2]	O*			
FUEL PARAMETER (% ash or % sulfur) = FP		%		%	
PM10 CONTROL DEVICE CODE[3]					
Avg. PM10 CONTROL EFFICIENCY[4] = CE		%		%	
PM10 EMISSIONS[5]		0.99 tons PM10 per yr		lbs PM10 per day	
PB EMISSION FACTOR (with units) = EF					
Emission Factor Source[1]	Control Efficiency Basis[2]				
PB CONTROL DEVICE CODE[3]					
Avg. PB CONTROL EFFICIENCY[4] = CE		%		%	
PB EMISSIONS[5]		tons PB per yr		lbs PB per day	

*Emission rates and factors used are from the permit application

**CEMS data for NOx and CO are calculated based upon the permit requirements and data substitution. SO2 emissions are calculated using Part 75, Appendix D monitoring requirements, and data substitution.

1. AP-42; CEMS; ST = Stack Test; F = Federal factor (EPA standard factor); O = Other (describe on separate sheet; use subject to DEQ approval)
2. A = Tested (by EPA reference method); B = Tested (other); C = Meterail Balance; D = Design; O = Other (describe on separate sheet)
3. See 3-digit control device codes listed in appendix.
4. Note control efficiency will be zero if there is no control device OR the emission factor accounts for controls (i.e. EF is identified to be "with controls")
5. Annual Emissions = ANNUAL THRUPUT x EF x FP x (1/2000) x (100-CE)/100; Ozone Emissions = DAILY THRUPUT x EF x FP x (100-CE)/100

2014 EMISSIONS CALCULATIONS
OPTION I: EMISSION FACTOR METHOD

REGISTRATION # 40989 *STACK NO:* 1 *POINT NO.:* 1 *SEGMENT NO.:* 2 *SCC NO.:* 20100101

		ANNUAL		PEAK OZONE SEASON (JUNE, JULY, AUGUST)	
THRUPUT (with units)		100124 MMBtu			
NO. OPERATING DAYS		13 days		days	
NO. OPERATING HOURS PER DAY		7.3 hours		hours	
DAILY THRUPUT (with units) = Thruput / days		NA			
TRS EMISSION FACTOR (with units) = EF					
Emission Factor Source[1]	Control Efficiency Basis[2]				
TRS CONTROL DEVICE CODE[3]					
Avg. TRS CONTROL EFFICIENCY[4] = CE		%		%	
TRS EMISSIONS[5]		NA tons TRS per yr		lbs per day	
TNMOC EMISSION FACTOR (with units) = EF					
Emission Factor Source[1]	Control Efficiency Basis[2]				
TNMOC CONTROL DEVICE CODE[3]					
Avg. TNMOC CONTROL EFFICIENCY[4] = CE		%		%	
TNMOC EMISSIONS[5]		NA tons TNMOC per yr		lbs per day	
CO EMISSION FACTOR (with units) = EF					
Emission Factor Source[1]	Control Efficiency Basis[2]	CEMS**			
CO CONTROL DEVICE CODE[3]					
Avg. CO CONTROL EFFICIENCY[4] = CE		%		%	
CO EMISSIONS[5]		0.89 tons CO per yr		lbs per day	
PM2.5 EMISSION FACTOR (with units) = EF					
Emission Factor Source[1]	Control Efficiency Basis[2]				
FUEL PARAMETER (% ash or % sulfur) = FP		%		%	
PM2.5 CONTROL DEVICE CODE[3]					
Avg. PM2.5 CONTROL EFFICIENCY[4] = CE		%		%	
PM2.5 EMISSIONS[5]		tons PM2.5 per yr		lbs per day	
NH3 EMISSION FACTOR (with units) = EF					
Emission Factor Source[1]	Control Efficiency Basis[2]				
NH3 CONTROL DEVICE CODE[3]					
Avg. NH3 CONTROL EFFICIENCY[4] = CE		%		%	
NH3 EMISSIONS[5]		NA tons NH3 per yr		lbs per day	

*Emission rates and factors used are from the permit application

**CEMS data for NOx and CO are calculated based upon the permit requirements and data substitution. SO2 emissions are calculated using Part 75, Appendix D monitoring requirements, and data substitution.

1. AP-42; CEMS; ST = Stack Test; F = Federal factor (EPA standard factor); O = Other (describe on separate sheet; use subject to DEQ approval)
2. A = Tested (by EPA reference method); B = Tested (other); C = Meterail Balance; D = Design; O = Other (describe on separate sheet)
3. See 3-digit control device codes listed in appendix.
4. Note control efficiency will be zero if there is no control device OR the emission factor accounts for controls (i.e. EF is identified to be "with controls")
5. Annual Emissions = ANNUAL THRUPUT x EF x FP x (1/2000) x (100-CE)/100; Ozone Emissions = DAILY THRUPUT x EF x FP x (100-CE)/100

2014 EMISSIONS CALCULATIONS
OPTION I: EMISSION FACTOR METHOD

REGISTRATION # 40989 *STACK NO:* 2 *POINT NO.:* 2 *SEGMENT NO.:* 1 *SCC NO.:* 20100201

		ANNUAL		PEAK OZONE SEASON (JUNE, JULY, AUGUST)	
THRUPUT (with units)		136376 MMBtu		12485 MMBtu	
NO. OPERATING DAYS		21 days		2 days	
NO. OPERATING HOURS PER DAY		6.6 hours		6.9 hours	
DAILY THRUPUT (with units) = Thruput / days		NA		6242.4 MMBtu/day	
VOC EMISSION FACTOR (with units) = EF		2.2 lbs/hr		2.2 lbs/hr	
Emission Factor Source[1]	Control Efficiency Basis[2]	O*		O*	
VOC CONTROL DEVICE CODE[3]					
Avg. VOC CONTROL EFFICIENCY[4] = CE		%		%	
VOC EMISSIONS[5]		0.15 tons VOC per yr		15.1 lbs VOC per day	
NOx EMISSION FACTOR (with units) = EF					
Emission Factor Source[1]	Control Efficiency Basis[2]	CEMS**		CEMS**	
NOx CONTROL DEVICE CODE[3]		205		205	
Avg. NOx CONTROL EFFICIENCY[4] = CE		%		%	
NOx EMISSIONS		1.92 tons NOx per yr		110.0 lbs NOx per day	
SO2 EMISSION FACTOR (with units) = EF					
Emission Factor Source[1]	Control Efficiency Basis[2]	O**			
FUEL PARAMETER (% ash or % sulfur) = FP		%		%	
SO2 CONTROL DEVICE CODE[3]					
Avg. SO2 CONTROL EFFICIENCY[4] = CE		%		%	
SO2 EMISSIONS[5]		0.06 tons SO2 per yr		lbs SO2 per day	
PM10 EMISSION FACTOR (with units) = EF		10 lbs/hr			
Emission Factor Source[1]	Control Efficiency Basis[2]	O*			
FUEL PARAMETER (% ash or % sulfur) = FP		%		%	
PM10 CONTROL DEVICE CODE[3]					
Avg. PM10 CONTROL EFFICIENCY[4] = CE		%		%	
PM10 EMISSIONS[5]		0.69 tons PM10 per yr		lbs PM10 per day	
PB EMISSION FACTOR (with units) = EF		NA			
Emission Factor Source[1]	Control Efficiency Basis[2]				
PB CONTROL DEVICE CODE[3]					
Avg. PB CONTROL EFFICIENCY[4] = CE		%		%	
PB EMISSIONS[5]		tons PB per yr		lbs PB per day	

*Emission rates and factors used are from the permit application

**CEMS data for NOx and CO are calculated based upon the permit requirements and data substitution. SO2 emissions are calculated using Part 75, Appendix D monitoring requirements, and data substitution.

1. AP-42; CEMS; ST = Stack Test; F = Federal factor (EPA standard factor); O = Other (describe on separate sheet; use subject to DEQ approval)
2. A = Tested (by EPA reference method); B = Tested (other); C = Meterail Balance; D = Design; O = Other (describe on separate sheet)
3. See 3-digit control device codes listed in appendix.
4. Note control efficiency will be zero if there is no control device OR the emission factor accounts for controls (i.e. EF is identified to be "with controls")
5. Annual Emissions = ANNUAL THRUPUT x EF x FP x (1/2000) x (100-CE)/100; Ozone Emissions = DAILY THRUPUT x EF x FP x (100-CE)/100

2014 EMISSIONS CALCULATIONS
OPTION I: EMISSION FACTOR METHOD

REGISTRATION # 40989 *STACK NO:* 2 *POINT NO.:* 2 *SEGMENT NO.:* 1 *SCC NO.:* 20100201

		ANNUAL		PEAK OZONE SEASON (JUNE, JULY, AUGUST)	
THRUPUT (with units)		136376 MMBtu			
NO. OPERATING DAYS		21 days		days	
NO. OPERATING HOURS PER DAY		6.6 hours		hours	
DAILY THRUPUT (with units) = Thruput / days		NA			
TRS EMISSION FACTOR (with units) = EF					
Emission Factor Source[1]	Control Efficiency Basis[2]				
TRS CONTROL DEVICE CODE[3]					
Avg. TRS CONTROL EFFICIENCY[4] = CE		%		%	
TRS EMISSIONS[5]		NA tons TRS per yr		lbs per day	
TNMOC EMISSION FACTOR (with units) = EF					
Emission Factor Source[1]	Control Efficiency Basis[2]				
TNMOC CONTROL DEVICE CODE[3]					
Avg. TNMOC CONTROL EFFICIENCY[4] = CE		%		%	
TNMOC EMISSIONS[5]		NA tons TNMOC per yr		lbs per day	
CO EMISSION FACTOR (with units) = EF					
Emission Factor Source[1]	Control Efficiency Basis[2]	CEMS**			
CO CONTROL DEVICE CODE[3]					
Avg. CO CONTROL EFFICIENCY[4] = CE		%		%	
CO EMISSIONS[5]		3.74 tons CO per yr		lbs per day	
PM2.5 EMISSION FACTOR (with units) = EF					
Emission Factor Source[1]	Control Efficiency Basis[2]				
FUEL PARAMETER (% ash or % sulfur) = FP		%		%	
PM2.5 CONTROL DEVICE CODE[3]					
Avg. PM2.5 CONTROL EFFICIENCY[4] = CE		%		%	
PM2.5 EMISSIONS[5]		tons PM2.5 per yr		lbs per day	
NH3 EMISSION FACTOR (with units) = EF					
Emission Factor Source[1]	Control Efficiency Basis[2]				
NH3 CONTROL DEVICE CODE[3]					
Avg. NH3 CONTROL EFFICIENCY[4] = CE		%		%	
NH3 EMISSIONS[5]		NA tons NH3 per yr		lbs per day	

*Emission rates and factors used are from the permit application

**CEMS data for NOx and CO are calculated based upon the permit requirements and data substitution. SO2 emissions are calculated using Part 75, Appendix D monitoring requirements, and data substitution.

1. AP-42; CEMS; ST = Stack Test; F = Federal factor (EPA standard factor); O = Other (describe on separate sheet; use subject to DEQ approval)
2. A = Tested (by EPA reference method); B = Tested (other); C = Meterail Balance; D = Design; O = Other (describe on separate sheet)
3. See 3-digit control device codes listed in appendix.
4. Note control efficiency will be zero if there is no control device OR the emission factor accounts for controls (i.e. EF is identified to be "with controls")
5. Annual Emissions = ANNUAL THRUPUT x EF x FP x (1/2000) x (100-CE)/100; Ozone Emissions = DAILY THRUPUT x EF x FP x (100-CE)/100

2014 EMISSIONS CALCULATIONS
OPTION I: EMISSION FACTOR METHOD

REGISTRATION # 40989 *STACK NO:* 2 *POINT NO.:* 2 *SEGMENT NO.:* 2 *SCC NO.:* 20100101

	ANNUAL		PEAK OZONE SEASON (JUNE, JULY, AUGUST)	
THRUPUT (with units)	109670 MMBtu		0 MMBtu	
NO. OPERATING DAYS	13 days		0 days	
NO. OPERATING HOURS PER DAY	7.5076923 hours		0 hours	
DAILY THRUPUT (with units) = Thruput / days	NA		0 MMBtu/day	
VOC EMISSION FACTOR (with units) = EF	5.5 lbs/hr		5.5 lbs/hr	
Emission Factor Source[1] / Control Efficiency Basis[2]	O*		O*	
VOC CONTROL DEVICE CODE[3]				
Avg. VOC CONTROL EFFICIENCY[4] = CE	%		%	
VOC EMISSIONS[5]	0.27 tons VOC per yr		0.0 lbs VOC per day	
NOx EMISSION FACTOR (with units) = EF				
Emission Factor Source[1] / Control Efficiency Basis[2]	CEMS**		CEMS**	
NOx CONTROL DEVICE CODE[3]	028		028	
Avg. NOx CONTROL EFFICIENCY[4] = CE	%		%	
NOx EMISSIONS	5.48 tons NOx per yr		0.0 lbs NOx per day	
SO2 EMISSION FACTOR (with units) = EF				
Emission Factor Source[1] / Control Efficiency Basis[2]	O**			
FUEL PARAMETER (% ash or % sulfur) = FP	%		%	
SO2 CONTROL DEVICE CODE[3]				
Avg. SO2 CONTROL EFFICIENCY[4] = CE	%		%	
SO2 EMISSIONS[5]	0.86 tons SO2 per yr		lbs SO2 per day	
PM10 EMISSION FACTOR (with units) = EF	21 lbs/hr			
Emission Factor Source[1] / Control Efficiency Basis[2]	O*			
FUEL PARAMETER (% ash or % sulfur) = FP	%		%	
PM10 CONTROL DEVICE CODE[3]				
Avg. PM10 CONTROL EFFICIENCY[4] = CE	%		%	
PM10 EMISSIONS[5]	1.02 tons PM10 per yr		lbs PM10 per day	
PB EMISSION FACTOR (with units) = EF				
Emission Factor Source[1] / Control Efficiency Basis[2]				
PB CONTROL DEVICE CODE[3]				
Avg. PB CONTROL EFFICIENCY[4] = CE	%		%	
PB EMISSIONS[5]	tons PB per yr		lbs PB per day	

*Emission rates and factors used are from the permit application

**CEMS data for NOx and CO are calculated based upon the permit requirements and data substitution. SO2 emissions are calculated using Part 75, Appendix D monitoring requirements, and data substitution.

1. AP-42; CEMS; ST = Stack Test; F = Federal factor (EPA standard factor); O = Other (describe on separate sheet; use subject to DEQ approval)
2. A = Tested (by EPA reference method); B = Tested (other); C = Meterail Balance; D = Design; O = Other (describe on separate sheet)
3. See 3-digit control device codes listed in appendix.
4. Note control efficiency will be zero if there is no control device OR the emission factor accounts for controls (i.e. EF is identified to be "with controls")
5. Annual Emissions = ANNUAL THRUPUT x EF x FP x (1/2000) x (100-CE)/100; Ozone Emissions = DAILY THRUPUT x EF x FP x (100-CE)/100

2014 EMISSIONS CALCULATIONS
OPTION I: EMISSION FACTOR METHOD

REGISTRATION # 40989 *STACK NO:* 2 *POINT NO.:* 2 *SEGMENT NO.:* 2 *SCC NO.:* 20100101

		ANNUAL		PEAK OZONE SEASON (JUNE, JULY, AUGUST)	
THRUPUT (with units)		109670 MMBtu			
NO. OPERATING DAYS		13 days		days	
NO. OPERATING HOURS PER DAY		7.5076923 hours		hours	
DAILY THRUPUT (with units) = Thruput / days		NA			
TRS EMISSION FACTOR (with units) = EF					
Emission Factor Source[1]	Control Efficiency Basis[2]				
TRS CONTROL DEVICE CODE[3]					
Avg. TRS CONTROL EFFICIENCY[4] = CE		%		%	
TRS EMISSIONS[5]		NA tons TRS per yr		lbs per day	
TNMOC EMISSION FACTOR (with units) = EF					
Emission Factor Source[1]	Control Efficiency Basis[2]				
TNMOC CONTROL DEVICE CODE[3]					
Avg. TNMOC CONTROL EFFICIENCY[4] = CE		%		%	
TNMOC EMISSIONS[5]		NA tons TNMOC per yr		lbs per day	
CO EMISSION FACTOR (with units) = EF					
Emission Factor Source[1]	Control Efficiency Basis[2]	CEMS**			
CO CONTROL DEVICE CODE[3]					
Avg. CO CONTROL EFFICIENCY[4] = CE		%		%	
CO EMISSIONS[5]		1.18 tons CO per yr		lbs per day	
PM2.5 EMISSION FACTOR (with units) = EF					
Emission Factor Source[1]	Control Efficiency Basis[2]				
FUEL PARAMETER (% ash or % sulfur) = FP		%		%	
PM2.5 CONTROL DEVICE CODE[3]					
Avg. PM2.5 CONTROL EFFICIENCY[4] = CE		%		%	
PM2.5 EMISSIONS[5]		tons PM2.5 per yr		lbs per day	
NH3 EMISSION FACTOR (with units) = EF					
Emission Factor Source[1]	Control Efficiency Basis[2]				
NH3 CONTROL DEVICE CODE[3]					
Avg. NH3 CONTROL EFFICIENCY[4] = CE		%		%	
NH3 EMISSIONS[5]		NA tons NH3 per yr		lbs per day	

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1. AP-42; CEMS; ST = Stack Test; F = Federal factor (EPA standard factor); O = Other (describe on separate sheet; use subject to DEQ approval)
2. A = Tested (by EPA reference method); B = Tested (other); C = Meterall Balance; D = Design; O = Other (describe on separate sheet)
3. See 3-digit control device codes listed in appendix.
4. Note control efficiency will be zero if there is no control device OR the emission factor accounts for controls (i.e. EF is identified to be "with controls")
5. Annual Emissions = ANNUAL THRUPUT x EF x FP x (1/2000) x (100-CE)/100; Ozone Emissions = DAILY THRUPUT x EF x FP x (100-CE)/100

2014 EMISSIONS CALCULATIONS
OPTION I: EMISSION FACTOR METHOD

REGISTRATION # 40989 *STACK NO:* 3 *POINT NO.:* 3 *SEGMENT NO.:* 1 *SCC NO.:* 20100201

		ANNUAL		PEAK OZONE SEASON (JUNE, JULY, AUGUST)	
THRUPUT (with units)		123454 MMBtu		12624 MMBtu	
NO. OPERATING DAYS		20 days		2 days	
NO. OPERATING HOURS PER DAY		6.1 hours		6.7 hours	
DAILY THRUPUT (with units) = Thruput / days		NA		6312.15 MMBtu/day	
VOC EMISSION FACTOR (with units) = EF		2.2 lbs/hr		2.2 lbs/hr	
Emission Factor Source[1]	Control Efficiency Basis[2]	O*		O*	
VOC CONTROL DEVICE CODE[3]					
Avg. VOC CONTROL EFFICIENCY[4] = CE		%		%	
VOC EMISSIONS[5]		0.13 tons VOC per yr		14.7 lbs VOC per day	
NOx EMISSION FACTOR (with units) = EF					
Emission Factor Source[1]	Control Efficiency Basis[2]	CEMS**		CEMS**	
NOx CONTROL DEVICE CODE[3]		205		205	
Avg. NOx CONTROL EFFICIENCY[4] = CE		%		%	
NOx EMISSIONS		1.70 tons NOx per yr		108.0 lbs NOx per day	
SO2 EMISSION FACTOR (with units) = EF					
Emission Factor Source[1]	Control Efficiency Basis[2]	O**			
FUEL PARAMETER (% ash or % sulfur) = FP		%		%	
SO2 CONTROL DEVICE CODE[3]					
Avg. SO2 CONTROL EFFICIENCY[4] = CE		%		%	
SO2 EMISSIONS[5]		0.06 tons SO2 per yr		lbs SO2 per day	
PM10 EMISSION FACTOR (with units) = EF		10 lbs/hr			
Emission Factor Source[1]	Control Efficiency Basis[2]	O*			
FUEL PARAMETER (% ash or % sulfur) = FP		%		%	
PM10 CONTROL DEVICE CODE[3]					
Avg. PM10 CONTROL EFFICIENCY[4] = CE		%		%	
PM10 EMISSIONS[5]		0.61 tons PM10 per yr		lbs PM10 per day	
PB EMISSION FACTOR (with units) = EF					
Emission Factor Source[1]	Control Efficiency Basis[2]				
PB CONTROL DEVICE CODE[3]					
Avg. PB CONTROL EFFICIENCY[4] = CE		%		%	
PB EMISSIONS[5]		tons PB per yr		lbs PB per day	

*Emission rates and factors used are from the permit application

**CEMS data for NOx and CO are calculated based upon the permit requirements and data substitution. SO2 emissions are calculated using Part 75, Appendix D monitoring requirements, and data substitution.

1. AP-42; CEMS; ST = Stack Test; F = Federal factor (EPA standard factor); O = Other (describe on separate sheet; use subject to DEQ approval)
2. A = Tested (by EPA reference method); B = Tested (other); C = Meterail Balance; D = Design; O = Other (describe on separate sheet)
3. See 3-digit control device codes listed in appendix.
4. Note control efficiency will be zero if there is no control device OR the emission factor accounts for controls (i.e. EF is identified to be "with controls")
5. Annual Emissions = ANNUAL THRUPUT x EF x FP x (1/2000) x (100-CE)/100; Ozone Emissions = DAILY THRUPUT x EF x FP x (100-CE)/100

2014 EMISSIONS CALCULATIONS
OPTION I: EMISSION FACTOR METHOD

REGISTRATION # 40989 *STACK NO:* 3 *POINT NO.:* 3 *SEGMENT NO.:* 2 *SCC NO.:* 20100101

		ANNUAL		PEAK OZONE SEASON (JUNE, JULY, AUGUST)	
THRUPUT (with units)		121960 MMBtu		0 MMBtu	
NO. OPERATING DAYS		15 days		0 days	
NO. OPERATING HOURS PER DAY		7.6 hours		0 hours	
DAILY THRUPUT (with units) = Thruput / days		NA		0 MMBtu/day	
VOC EMISSION FACTOR (with units) = EF		5.5 lbs/hr		5.5 lbs/hr	
Emission Factor Source[1]	Control Efficiency Basis[2]	O*		O*	
VOC CONTROL DEVICE CODE[3]					
Avg. VOC CONTROL EFFICIENCY[4] = CE		%		%	
VOC EMISSIONS[5]		0.32 tons VOC per yr		0.0 lbs VOC per day	
NOx EMISSION FACTOR (with units) = EF					
Emission Factor Source[1]	Control Efficiency Basis[2]	CEMS**		CEMS**	
NOx CONTROL DEVICE CODE[3]		028		028	
Avg. NOx CONTROL EFFICIENCY[4] = CE		%		%	
NOx EMISSIONS		6.32 tons NOx per yr		0.0 lbs NOx per day	
SO2 EMISSION FACTOR (with units) = EF					
Emission Factor Source[1]	Control Efficiency Basis[2]	O**			
FUEL PARAMETER (% ash or % sulfur) = FP		%		%	
SO2 CONTROL DEVICE CODE[3]					
Avg. SO2 CONTROL EFFICIENCY[4] = CE		%		%	
SO2 EMISSIONS[5]		0.96 tons SO2 per yr		lbs SO2 per day	
PM10 EMISSION FACTOR (with units) = EF		21 lbs/hr			
Emission Factor Source[1]	Control Efficiency Basis[2]	O*			
FUEL PARAMETER (% ash or % sulfur) = FP		%		%	
PM10 CONTROL DEVICE CODE[3]					
Avg. PM10 CONTROL EFFICIENCY[4] = CE		%		%	
PM10 EMISSIONS[5]		1.20 tons PM10 per yr		lbs PM10 per day	
PB EMISSION FACTOR (with units) = EF					
Emission Factor Source[1]	Control Efficiency Basis[2]				
PB CONTROL DEVICE CODE[3]					
Avg. PB CONTROL EFFICIENCY[4] = CE		%		%	
PB EMISSIONS[5]		tons PB per yr		lbs PB per day	

*Emission rates and factors used are from the permit application

**CEMS data for NOx and CO are calculated based upon the permit requirements and data substitution. SO2 emissions are calculated using Part 75, Appendix D monitoring requirements, and data substitution.

1. AP-42; CEMS; ST = Stack Test; F = Federal factor (EPA standard factor); O = Other (describe on separate sheet; use subject to DEQ approval)
2. A = Tested (by EPA reference method); B = Tested (other); C = Meterail Balance; D = Design; O = Other (describe on separate sheet)
3. See 3-digit control device codes listed in appendix.
4. Note control efficiency will be zero if there is no control device OR the emission factor accounts for controls (i.e. EF is identified to be "with controls")
5. Annual Emissions = ANNUAL THRUPUT x EF x FP x (1/2000) x (100-CE)/100; Ozone Emissions = DAILY THRUPUT x EF x FP x (100-CE)/100

2014 EMISSIONS CALCULATIONS
OPTION I: EMISSION FACTOR METHOD

REGISTRATION # 40989 *STACK NO:* 3 *POINT NO.:* 3 *SEGMENT NO.:* 1 *SCC NO.:* 20100201

		ANNUAL		PEAK OZONE SEASON (JUNE, JULY, AUGUST)	
THRUPUT (with units)		123454 MMBtu			
NO. OPERATING DAYS		20 days		days	
NO. OPERATING HOURS PER DAY		6.1 hours		hours	
DAILY THRUPUT (with units) = Thruput / days		NA			
TRS EMISSION FACTOR (with units) = EF					
Emission Factor Source[1]	Control Efficiency Basis[2]				
TRS CONTROL DEVICE CODE[3]					
Avg. TRS CONTROL EFFICIENCY[4] = CE		%		%	
TRS EMISSIONS[5]		NA tons TRS per yr		lbs per day	
TNMOC EMISSION FACTOR (with units) = EF					
Emission Factor Source[1]	Control Efficiency Basis[2]				
TNMOC CONTROL DEVICE CODE[3]					
Avg. TNMOC CONTROL EFFICIENCY[4] = CE		%		%	
TNMOC EMISSIONS[5]		NA tons TNMOC per yr		lbs per day	
CO EMISSION FACTOR (with units) = EF					
Emission Factor Source[1]	Control Efficiency Basis[2]	CEMS**			
CO CONTROL DEVICE CODE[3]					
Avg. CO CONTROL EFFICIENCY[4] = CE		%		%	
CO EMISSIONS[5]		1.86 tons CO per yr		lbs per day	
PM2.5 EMISSION FACTOR (with units) = EF					
Emission Factor Source[1]	Control Efficiency Basis[2]				
FUEL PARAMETER (% ash or % sulfur) = FP		%		%	
PM2.5 CONTROL DEVICE CODE[3]					
Avg. PM2.5 CONTROL EFFICIENCY[4] = CE		%		%	
PM2.5 EMISSIONS[5]		tons PM2.5 per yr		lbs per day	
NH3 EMISSION FACTOR (with units) = EF					
Emission Factor Source[1]	Control Efficiency Basis[2]				
NH3 CONTROL DEVICE CODE[3]					
Avg. NH3 CONTROL EFFICIENCY[4] = CE		%		%	
NH3 EMISSIONS[5]		NA tons NH3 per yr		lbs per day	

*Emission rates and factors used are from the permit application

**CEMS data for NOx and CO are calculated based upon the permit requirements and data substitution. SO2 emissions are calculated using Part 75, Appendix D monitoring requirements, and data substitution.

1. AP-42; CEMS; ST = Stack Test; F = Federal factor (EPA standard factor); O = Other (describe on separate sheet; use subject to DEQ approval)
2. A = Tested (by EPA reference method); B = Tested (other); C = Meterail Balance; D = Design; O = Other (describe on separate sheet)
3. See 3-digit control device codes listed in appendix.
4. Note control efficiency will be zero if there is no control device OR the emission factor accounts for controls (i.e. EF is identified to be "with controls")
5. Annual Emissions = ANNUAL THRUPUT x EF x FP x (1/2000) x (100-CE)/100; Ozone Emissions = DAILY THRUPUT x EF x FP x (100-CE)/100

2014 EMISSIONS CALCULATIONS
OPTION I: EMISSION FACTOR METHOD

REGISTRATION # 40989 *STACK NO:* 3 *POINT NO.:* 3 *SEGMENT NO.:* 2 *SCC NO.:* 20100101

	ANNUAL	PEAK OZONE SEASON (JUNE, JULY, AUGUST)
THRUPUT (with units)	121960 MMBtu	
NO. OPERATING DAYS	15 days	days
NO. OPERATING HOURS PER DAY	7.6 hours	hours
DAILY THRUPUT (with units) = Thruput / days	NA	
TRS EMISSION FACTOR (with units) = EF		
Emission Factor Source[1] / Control Efficiency Basis[2]		
TRS CONTROL DEVICE CODE[3]		
Avg. TRS CONTROL EFFICIENCY[4] = CE	%	%
TRS EMISSIONS[5]	NA tons TRS per yr	lbs per day
TNMOC EMISSION FACTOR (with units) = EF		
Emission Factor Source[1] / Control Efficiency Basis[2]		
TNMOC CONTROL DEVICE CODE[3]		
Avg. TNMOC CONTROL EFFICIENCY[4] = CE	%	%
TNMOC EMISSIONS[5]	NA tons TNMOC per yr	lbs per day
CO EMISSION FACTOR (with units) = EF		
Emission Factor Source[1] / Control Efficiency Basis[2]	CEMS**	
CO CONTROL DEVICE CODE[3]		
Avg. CO CONTROL EFFICIENCY[4] = CE	%	%
CO EMISSIONS[5]	0.73 tons CO per yr	lbs per day
PM2.5 EMISSION FACTOR (with units) = EF		
Emission Factor Source[1] / Control Efficiency Basis[2]		
FUEL PARAMETER (% ash or % sulfur) = FP	%	%
PM2.5 CONTROL DEVICE CODE[3]		
Avg. PM2.5 CONTROL EFFICIENCY[4] = CE	%	%
PM2.5 EMISSIONS[5]	tons PM2.5 per yr	lbs per day
NH3 EMISSION FACTOR (with units) = EF		
Emission Factor Source[1] / Control Efficiency Basis[2]		
NH3 CONTROL DEVICE CODE[3]		
Avg. NH3 CONTROL EFFICIENCY[4] = CE	%	%
NH3 EMISSIONS[5]	NA tons NH3 per yr	lbs per day

*Emission rates and factors used are from the permit application

**CEMS data for NOx and CO are calculated based upon the permit requirements and data substitution. SO2 emissions are calculated using Part 75, Appendix D monitoring requirements, and data substitution.

1. AP-42; CEMS; ST = Stack Test; F = Federal factor (EPA standard factor); O = Other (describe on separate sheet; use subject to DEQ approval)
2. A = Tested (by EPA reference method); B = Tested (other); C = Meterail Balance; D = Design; O = Other (describe on separate sheet)
3. See 3-digit control device codes listed in appendix.
4. Note control efficiency will be zero if there is no control device OR the emission factor accounts for controls (i.e. EF is identified to be "with controls")
5. Annual Emissions = ANNUAL THRUPUT x EF x FP x (1/2000) x (100-CE)/100; Ozone Emissions = DAILY THRUPUT x EF x FP x (100-CE)/100

2014 EMISSIONS CALCULATIONS
OPTION I: EMISSION FACTOR METHOD

REGISTRATION # 40989 STACK NO: 4 POINT NO.: 4 SEGMENT NO.: 1 SCC NO.: 20100201

		ANNUAL		PEAK OZONE SEASON (JUNE, JULY, AUGUST)	
THRUPUT (with units)		146071 MMBtu		7382.5 MMBtu	
NO. OPERATING DAYS		23 days		2 days	
NO. OPERATING HOURS PER DAY		6.3 hours		4.0 hours	
DAILY THRUPUT (with units) = Thruput / days		NA		3691.25 MMBtu/day	
VOC EMISSION FACTOR (with units) = EF		2.2 lbs/hr		2.2 lbs/hr	
Emission Factor Source[1]	Control Efficiency Basis[2]	O*		O*	
VOC CONTROL DEVICE CODE[3]					
Avg. VOC CONTROL EFFICIENCY[4] = CE		%		%	
VOC EMISSIONS[5]		0.16 tons VOC per yr		8.8 lbs VOC per day	
NOx EMISSION FACTOR (with units) = EF					
Emission Factor Source[1]	Control Efficiency Basis[2]	CEMS**		CEMS**	
NOx CONTROL DEVICE CODE[3]		205		205	
Avg. NOx CONTROL EFFICIENCY[4] = CE		%		%	
NOx EMISSIONS		2.06 tons NOx per yr		87.0 lbs NOx per day	
SO2 EMISSION FACTOR (with units) = EF					
Emission Factor Source[1]	Control Efficiency Basis[2]	O**			
FUEL PARAMETER (% ash or % sulfur) = FP		%		%	
SO2 CONTROL DEVICE CODE[3]					
Avg. SO2 CONTROL EFFICIENCY[4] = CE		%		%	
SO2 EMISSIONS[5]		0.06 tons SO2 per yr		lbs SO2 per day	
PM10 EMISSION FACTOR (with units) = EF		10 lbs/hr			
Emission Factor Source[1]	Control Efficiency Basis[2]	O*			
FUEL PARAMETER (% ash or % sulfur) = FP		%		%	
PM10 CONTROL DEVICE CODE[3]					
Avg. PM10 CONTROL EFFICIENCY[4] = CE		%		%	
PM10 EMISSIONS[5]		0.73 tons PM10 per yr		lbs PM10 per day	
PB EMISSION FACTOR (with units) = EF					
Emission Factor Source[1]	Control Efficiency Basis[2]				
PB CONTROL DEVICE CODE[3]					
Avg. PB CONTROL EFFICIENCY[4] = CE		%		%	
PB EMISSIONS[5]		tons PB per yr		lbs PB per day	

*Emission rates and factors used are from the permit application

**CEMS data for NOx and CO are calculated based upon the permit requirements and data substitution. SO2 emissions are calculated using Part 75, Appendix D monitoring requirements, and data substitution.

1. AP-42; CEMS; ST = Stack Test; F = Federal factor (EPA standard factor); O = Other (describe on separate sheet; use subject to DEQ approval)
2. A = Tested (by EPA reference method); B = Tested (other); C = Meterail Balance; D = Design; O = Other (describe on separate sheet)
3. See 3-digit control device codes listed in appendix.
4. Note control efficiency will be zero if there is no control device OR the emission factor accounts for controls (i.e. EF is identified to be "with controls")
5. Annual Emissions = ANNUAL THRUPUT x EF x FP x (1/2000) x (100-CE)/100; Ozone Emissions = DAILY THRUPUT x EF x FP x (100-CE)/100

2014 EMISSIONS CALCULATIONS
OPTION I: EMISSION FACTOR METHOD

REGISTRATION # 40989 *STACK NO:* 4 *POINT NO.:* 4 *SEGMENT NO.:* 1 *SCC NO.:* 20100201

		ANNUAL		PEAK OZONE SEASON (JUNE, JULY, AUGUST)	
THRUPUT (with units)		146071 MMBtu			
NO. OPERATING DAYS		23 days		days	
NO. OPERATING HOURS PER DAY		6.3 hours		hours	
DAILY THRUPUT (with units) = Thruput / days		NA			
TRS EMISSION FACTOR (with units) = EF					
Emission Factor Source[1]	Control Efficiency Basis[2]				
TRS CONTROL DEVICE CODE[3]					
Avg. TRS CONTROL EFFICIENCY[4] = CE		%		%	
TRS EMISSIONS[5]		NA tons TRS per yr		lbs per day	
TNMOC EMISSION FACTOR (with units) = EF					
Emission Factor Source[1]	Control Efficiency Basis[2]				
TNMOC CONTROL DEVICE CODE[3]					
Avg. TNMOC CONTROL EFFICIENCY[4] = CE		%		%	
TNMOC EMISSIONS[5]		NA tons TNMOC per yr		lbs per day	
CO EMISSION FACTOR (with units) = EF					
Emission Factor Source[1]	Control Efficiency Basis[2]	CEMS**			
CO CONTROL DEVICE CODE[3]					
Avg. CO CONTROL EFFICIENCY[4] = CE		%		%	
CO EMISSIONS[5]		2.72 tons CO per yr		lbs per day	
PM2.5 EMISSION FACTOR (with units) = EF					
Emission Factor Source[1]	Control Efficiency Basis[2]				
FUEL PARAMETER (% ash or % sulfur) = FP		%		%	
PM2.5 CONTROL DEVICE CODE[3]					
Avg. PM2.5 CONTROL EFFICIENCY[4] = CE		%		%	
PM2.5 EMISSIONS[5]		tons PM2.5 per yr		lbs per day	
NH3 EMISSION FACTOR (with units) = EF					
Emission Factor Source[1]	Control Efficiency Basis[2]				
NH3 CONTROL DEVICE CODE[3]					
Avg. NH3 CONTROL EFFICIENCY[4] = CE		%		%	
NH3 EMISSIONS[5]		NA tons NH3 per yr		lbs per day	

*Emission rates and factors used are from the permit application

**CEMS data for NOx and CO are calculated based upon the permit requirements and data substitution. SO2 emissions are calculated using Part 75, Appendix D monitoring requirements, and data substitution.

1. AP-42; CEMS; ST = Stack Test; F = Federal factor (EPA standard factor); O = Other (describe on separate sheet; use subject to DEQ approval)
2. A = Tested (by EPA reference method); B = Tested (other); C = Meterail Balance; D = Design; O = Other (describe on separate sheet)
3. See 3-digit control device codes listed in appendix.
4. Note control efficiency will be zero if there is no control device OR the emission factor accounts for controls (i.e. EF is identified to be "with controls")
5. Annual Emissions = ANNUAL THRUPUT x EF x FP x (1/2000) x (100-CE)/100; Ozone Emissions = DAILY THRUPUT x EF x FP x (100-CE)/100

2014 EMISSIONS CALCULATIONS
OPTION I: EMISSION FACTOR METHOD

REGISTRATION # 40989 *STACK NO:* 4 *POINT NO.:* 4 *SEGMENT NO.:* 2 *SCC NO.:* 20100101

		ANNUAL		PEAK OZONE SEASON (JUNE, JULY, AUGUST)	
THRUPUT (with units)		122658 MMBtu		0 MMBtu	
NO. OPERATING DAYS		15 days		0 days	
NO. OPERATING HOURS PER DAY		7.3 hours		0.0 hours	
DAILY THRUPUT (with units) = Thruput / days		NA		0 MMBtu/day	
VOC EMISSION FACTOR (with units) = EF		5.5 lbs/hr		5.5 lbs/hr	
Emission Factor Source[1]	Control Efficiency Basis[2]	O*		O*	
VOC CONTROL DEVICE CODE[3]					
Avg. VOC CONTROL EFFICIENCY[4] = CE		%		%	
VOC EMISSIONS[5]		0.30 tons VOC per yr		0.0 lbs VOC per day	
NOx EMISSION FACTOR (with units) = EF					
Emission Factor Source[1]	Control Efficiency Basis[2]	CEMS**		CEMS**	
NOx CONTROL DEVICE CODE[3]		028		028	
Avg. NOx CONTROL EFFICIENCY[4] = CE		%		%	
NOx EMISSIONS		6.48 tons NOx per yr		0.0 lbs NOx per day	
SO2 EMISSION FACTOR (with units) = EF					
Emission Factor Source[1]	Control Efficiency Basis[2]	O**			
FUEL PARAMETER (% ash or % sulfur) = FP		%		%	
SO2 CONTROL DEVICE CODE[3]					
Avg. SO2 CONTROL EFFICIENCY[4] = CE		%		%	
SO2 EMISSIONS[5]		0.82 tons SO2 per yr		lbs SO2 per day	
PM10 EMISSION FACTOR (with units) = EF		21 lbs/hr			
Emission Factor Source[1]	Control Efficiency Basis[2]	O*			
FUEL PARAMETER (% ash or % sulfur) = FP		%		%	
PM10 CONTROL DEVICE CODE[3]					
Avg. PM10 CONTROL EFFICIENCY[4] = CE		%		%	
PM10 EMISSIONS[5]		1.14 tons PM10 per yr		lbs PM10 per day	
PB EMISSION FACTOR (with units) = EF					
Emission Factor Source[1]	Control Efficiency Basis[2]				
PB CONTROL DEVICE CODE[3]					
Avg. PB CONTROL EFFICIENCY[4] = CE		%		%	
PB EMISSIONS[5]		tons PB per yr		lbs PB per day	

*Emission rates and factors used are from the permit application

**CEMS data for NOx and CO are calculated based upon the permit requirements and data substitution. SO2 emissions are calculated using Part 75, Appendix D monitoring requirements, and data substitution.

1. AP-42; CEMS; ST = Stack Test; F = Federal factor (EPA standard factor); O = Other (describe on separate sheet; use subject to DEQ approval)
2. A = Tested (by EPA reference method); B = Tested (other); C = Meterail Balance; D = Design; O = Other (describe on separate sheet)
3. See 3-digit control device codes listed in appendix.
4. Note control efficiency will be zero if there is no control device OR the emission factor accounts for controls (i.e. EF is identified to be "with controls")
5. Annual Emissions = ANNUAL THRUPUT x EF x FP x (1/2000) x (100-CE)/100; Ozone Emissions = DAILY THRUPUT x EF x FP x (100-CE)/100

2014 EMISSIONS CALCULATIONS
OPTION I: EMISSION FACTOR METHOD

REGISTRATION # 40989 *STACK NO:* 4 *POINT NO.:* 4 *SEGMENT NO.:* 2 *SCC NO.:* 20100101

		ANNUAL		PEAK OZONE SEASON (JUNE, JULY, AUGUST)	
THRUPUT (with units)		122658 MMBtu			
NO. OPERATING DAYS		15 days		days	
NO. OPERATING HOURS PER DAY		7.3 hours		hours	
DAILY THRUPUT (with units) = Thruput / days		NA			
TRS EMISSION FACTOR (with units) = EF					
Emission Factor Source[1]	Control Efficiency Basis[2]				
TRS CONTROL DEVICE CODE[3]					
Avg. TRS CONTROL EFFICIENCY[4] = CE		%		%	
TRS EMISSIONS[5]		NA tons TRS per yr		lbs per day	
TNMOC EMISSION FACTOR (with units) = EF					
Emission Factor Source[1]	Control Efficiency Basis[2]				
TNMOC CONTROL DEVICE CODE[3]					
Avg. TNMOC CONTROL EFFICIENCY[4] = CE		%		%	
TNMOC EMISSIONS[5]		NA tons TNMOC per yr		lbs per day	
CO EMISSION FACTOR (with units) = EF					
Emission Factor Source[1]	Control Efficiency Basis[2]	CEMS**			
CO CONTROL DEVICE CODE[3]					
Avg. CO CONTROL EFFICIENCY[4] = CE		%		%	
CO EMISSIONS[5]		1.15 tons CO per yr		lbs per day	
PM2.5 EMISSION FACTOR (with units) = EF					
Emission Factor Source[1]	Control Efficiency Basis[2]				
FUEL PARAMETER (% ash or % sulfur) = FP		%		%	
PM2.5 CONTROL DEVICE CODE[3]					
Avg. PM2.5 CONTROL EFFICIENCY[4] = CE		%		%	
PM2.5 EMISSIONS[5]		tons PM2.5 per yr		lbs per day	
NH3 EMISSION FACTOR (with units) = EF					
Emission Factor Source[1]	Control Efficiency Basis[2]				
NH3 CONTROL DEVICE CODE[3]					
Avg. NH3 CONTROL EFFICIENCY[4] = CE		%		%	
NH3 EMISSIONS[5]		NA tons NH3 per yr		lbs per day	

*Emission rates and factors used are from the permit application

**CEMS data for NOx and CO are calculated based upon the permit requirements and data substitution. SO2 emissions are calculated using Part 75, Appendix D monitoring requirements, and data substitution.

1. AP-42; CEMS; ST = Stack Test; F = Federal factor (EPA standard factor); O = Other (describe on separate sheet; use subject to DEQ approval)
2. A = Tested (by EPA reference method); B = Tested (other); C = Meterail Balance; D = Design; O = Other (describe on separate sheet)
3. See 3-digit control device codes listed in appendix.
4. Note control efficiency will be zero if there is no control device OR the emission factor accounts for controls (i.e. EF is identified to be "with controls")
5. Annual Emissions = ANNUAL THRUPUT x EF x FP x (1/2000) x (100-CE)/100; Ozone Emissions = DAILY THRUPUT x EF x FP x (100-CE)/100

2014 EMISSIONS CALCULATIONS
OPTION I: EMISSION FACTOR METHOD

REGISTRATION # 40989 *STACK NO:* 5 *POINT NO.:* 5 *SEGMENT NO.:* 1 *SCC NO.:* 20100201

		ANNUAL		PEAK OZONE SEASON (JUNE, JULY, AUGUST)	
THRUPUT (with units)		1027046 MMBtu		300203 MMBtu	
NO. OPERATING DAYS		83 days		27 days	
NO. OPERATING HOURS PER DAY		6.8 hours		6.4 hours	
DAILY THRUPUT (with units) = Thruput / days		NA		11118.6 MMBtu/day	
VOC EMISSION FACTOR (with units) = EF		3.2 lbs/hr		3.2 lbs/hr	
Emission Factor Source[1]	Control Efficiency Basis[2]	O*		O*	
VOC CONTROL DEVICE CODE[3]					
Avg. VOC CONTROL EFFICIENCY[4] = CE		%		%	
VOC EMISSIONS[5]		0.91 tons VOC per yr		20.5 lbs VOC per day	
NOx EMISSION FACTOR (with units) = EF					
Emission Factor Source[1]	Control Efficiency Basis[2]	CEMS**		CEMS**	
NOx CONTROL DEVICE CODE[3]		205		205	
Avg. NOx CONTROL EFFICIENCY[4] = CE		%		%	
NOx EMISSIONS		14.47 tons NOx per yr		266.2 lbs NOx per day	
SO2 EMISSION FACTOR (with units) = EF					
Emission Factor Source[1]	Control Efficiency Basis[2]	O**			
FUEL PARAMETER (% ash or % sulfur) = FP		%		%	
SO2 CONTROL DEVICE CODE[3]					
Avg. SO2 CONTROL EFFICIENCY[4] = CE		%		%	
SO2 EMISSIONS[5]		0.28 tons SO2 per yr		lbs SO2 per day	
PM10 EMISSION FACTOR (with units) = EF		18 lbs/hr			
Emission Factor Source[1]	Control Efficiency Basis[2]	O*			
FUEL PARAMETER (% ash or % sulfur) = FP		%		%	
PM10 CONTROL DEVICE CODE[3]					
Avg. PM10 CONTROL EFFICIENCY[4] = CE		%		%	
PM10 EMISSIONS[5]		5.11 tons PM10 per yr		lbs PM10 per day	
PB EMISSION FACTOR (with units) = EF					
Emission Factor Source[1]	Control Efficiency Basis[2]				
PB CONTROL DEVICE CODE[3]					
Avg. PB CONTROL EFFICIENCY[4] = CE		%		%	
PB EMISSIONS[5]		tons PB per yr		lbs PB per day	

*Emission rates and factors used are from the permit application

**CEMS data for NOx is calculated based upon the permit requirements and data substitution. SO2 emissions are calculated using Part 75, Appendix D monitoring requirements, and data substitution.

1. AP-42; CEMS; ST = Stack Test; F = Federal factor (EPA standard factor); O = Other (describe on separate sheet; use subject to DEQ approval)
2. A = Tested (by EPA reference method); B = Tested (other); C = Materail Balance; D = Design; O = Other (describe on separate sheet)
3. See 3-digit control device codes listed in appendix.
4. Note control efficiency will be zero if there is no control device OR the emission factor accounts for controls (i.e. EF is identified to be "with controls")
5. Annual Emissions = ANNUAL THRUPUT x EF x FP x (1/2000) x (100-CE)/100; Ozone Emissions = DAILY THRUPUT x EF x FP x (100-CE)/100

2014 EMISSIONS CALCULATIONS
OPTION I: EMISSION FACTOR METHOD

REGISTRATION # 40989 *STACK NO:* 5 *POINT NO.:* 5 *SEGMENT NO.:* 1 *SCC NO.:* 20100201

		ANNUAL		PEAK OZONE SEASON (JUNE, JULY, AUGUST)	
THRUPUT (with units)		1027046 MMBtu			
NO. OPERATING DAYS		83 days		days	
NO. OPERATING HOURS PER DAY		6.8 hours		hours	
DAILY THRUPUT (with units) = Thruput / days		NA			
TRS EMISSION FACTOR (with units) = EF					
Emission Factor Source[1]	Control Efficiency Basis[2]				
TRS CONTROL DEVICE CODE[3]					
Avg. TRS CONTROL EFFICIENCY[4] = CE		%		%	
TRS EMISSIONS[5]		NA tons TRS per yr		lbs per day	
TNMOC EMISSION FACTOR (with units) = EF					
Emission Factor Source[1]	Control Efficiency Basis[2]				
TNMOC CONTROL DEVICE CODE[3]					
Avg. TNMOC CONTROL EFFICIENCY[4] = CE		%		%	
TNMOC EMISSIONS[5]		NA tons TNMOC per yr		lbs per day	
CO EMISSION FACTOR (with units) = EF		0	0		
Emission Factor Source[1]	Control Efficiency Basis[2]	O***			
CO CONTROL DEVICE CODE[3]					
Avg. CO CONTROL EFFICIENCY[4] = CE		%		%	
CO EMISSIONS[5]		9.58 tons CO per yr		lbs per day	
PM2.5 EMISSION FACTOR (with units) = EF					
Emission Factor Source[1]	Control Efficiency Basis[2]				
FUEL PARAMETER (% ash or % sulfur) = FP		%		%	
PM2.5 CONTROL DEVICE CODE[3]					
Avg. PM2.5 CONTROL EFFICIENCY[4] = CE		%		%	
PM2.5 EMISSIONS[5]		tons PM2.5 per yr		lbs per day	
NH3 EMISSION FACTOR (with units) = EF					
Emission Factor Source[1]	Control Efficiency Basis[2]				
NH3 CONTROL DEVICE CODE[3]					
Avg. NH3 CONTROL EFFICIENCY[4] = CE		%		%	
NH3 EMISSIONS[5]		NA tons NH3 per yr		lbs per day	

***Emission factor in lbs/MMBtu equivalent to the concentration limit in the permit (Gas 9 ppm@15% O2, Oil 20 ppm@15%O2):

EF CO gas (lb/MMBtu) = K x COppm x Fd x 20.9/ (20.9 - %O2)

$= (7.267 \times 10^{-8}) \times 9 \times 8710 \times 20.9/(20.9 - 15)$

$= 0.02$ lb CO/MMBtu

1. AP-42; CEMS; ST = Stack Test; F = Federal factor (EPA standard factor); O = Other (describe on separate sheet; use subject to DEQ approval)
2. A = Tested (by EPA reference method); B = Tested (other); C = Meterail Balance; D = Design; O = Other (describe on separate sheet)
3. See 3-digit control device codes listed in appendix.
4. Note control efficiency will be zero if there is no control device OR the emission factor accounts for controls (i.e. EF is identified to be "with controls")
5. Annual Emissions = ANNUAL THRUPUT x EF x FP x (1/2000) x (100-CE)/100; Ozone Emissions = DAILY THRUPUT x EF x FP x (100-CE)/100

2014 EMISSIONS CALCULATIONS
OPTION I: EMISSION FACTOR METHOD

REGISTRATION # 40989 *STACK NO:* 5 *POINT NO.:* 5 *SEGMENT NO.:* 2 *SCC NO.:* 20100101

		ANNUAL		PEAK OZONE SEASON (JUNE, JULY, AUGUST)	
THRUPUT (with units)		213810 MMBtu		0 MMBtu	
NO. OPERATING DAYS		15 days		0 days	
NO. OPERATING HOURS PER DAY		6.9 hours		0 hours	
DAILY THRUPUT (with units) = Thruput / days		NA		0 MMBtu/day	
VOC EMISSION FACTOR (with units) = EF		8 lbs/hr		8.0 lbs/hr	
Emission Factor Source[1]	Control Efficiency Basis[2]	O*		O*	
VOC CONTROL DEVICE CODE[3]					
Avg. VOC CONTROL EFFICIENCY[4] = CE		%		%	
VOC EMISSIONS[5]		0.41 tons VOC per yr		0.0 lbs VOC per day	
NOx EMISSION FACTOR (with units) = EF					
Emission Factor Source[1]	Control Efficiency Basis[2]	CEMS**		CEMS**	
NOx CONTROL DEVICE CODE[3]		028		028	
Avg. NOx CONTROL EFFICIENCY[4] = CE		%		%	
NOx EMISSIONS		12.07 tons NOx per yr		0.0 lbs NOx per day	
SO2 EMISSION FACTOR (with units) = EF					
Emission Factor Source[1]	Control Efficiency Basis[2]	O**			
FUEL PARAMETER (% ash or % sulfur) = FP		%		%	
SO2 CONTROL DEVICE CODE[3]					
Avg. SO2 CONTROL EFFICIENCY[4] = CE		%		%	
SO2 EMISSIONS[5]		1.76 tons SO2 per yr		lbs SO2 per day	
PM10 EMISSION FACTOR (with units) = EF		36 lbs/hr			
Emission Factor Source[1]	Control Efficiency Basis[2]	O*			
FUEL PARAMETER (% ash or % sulfur) = FP		%		%	
PM10 CONTROL DEVICE CODE[3]					
Avg. PM10 CONTROL EFFICIENCY[4] = CE		%		%	
PM10 EMISSIONS[5]		1.86 tons PM10 per yr		lbs PM10 per day	
PB EMISSION FACTOR (with units) = EF					
Emission Factor Source[1]	Control Efficiency Basis[2]				
PB CONTROL DEVICE CODE[3]					
Avg. PB CONTROL EFFICIENCY[4] = CE		%		%	
PB EMISSIONS[5]		tons PB per yr		lbs PB per day	

*Emission rates and factors used are from the permit application

**CEMS data for NOx is calculated based upon the permit requirements and data substitution. SO2 emissions are calculated using Part 75, Appendix D monitoring requirements, and data substitution.

1. AP-42; CEMS; ST = Stack Test; F = Federal factor (EPA standard factor); O = Other (describe on separate sheet; use subject to DEQ approval)
2. A = Tested (by EPA reference method); B = Tested (other); C = Meterail Balance; D = Design; O = Other (describe on separate sheet)
3. See 3-digit control device codes listed in appendix.
4. Note control efficiency will be zero if there is no control device OR the emission factor accounts for controls (i.e. EF is identified to be "with controls")
5. Annual Emissions = ANNUAL THRUPUT x EF x FP x (1/2000) x (100-CE)/100; Ozone Emissions = DAILY THRUPUT x EF x FP x (100-CE)/100

2014 EMISSIONS CALCULATIONS
OPTION I: EMISSION FACTOR METHOD

REGISTRATION #	40989	STACK NO:	5	POINT NO.:	5	SEGMENT NO.:	2	SCC NO.:	20100101

		ANNUAL		PEAK OZONE SEASON (JUNE, JULY, AUGUST)	
THRUPUT (with units)		213810 MMBtu			
NO. OPERATING DAYS		15 days		days	
NO. OPERATING HOURS PER DAY		6.9 hours		hours	
DAILY THRUPUT (with units) = Thruput / days		NA			
TRS EMISSION FACTOR (with units) = EF					
Emission Factor Source[1]	Control Efficiency Basis[2]				
TRS CONTROL DEVICE CODE[3]					
Avg. TRS CONTROL EFFICIENCY[4] = CE		%		%	
TRS EMISSIONS[5]		NA tons TRS per yr		lbs per day	
TNMOC EMISSION FACTOR (with units) = EF					
Emission Factor Source[1]	Control Efficiency Basis[2]				
TNMOC CONTROL DEVICE CODE[3]					
Avg. TNMOC CONTROL EFFICIENCY[4] = CE		%		%	
TNMOC EMISSIONS[5]		NA tons TNMOC per yr		lbs per day	
CO EMISSION FACTOR (with units) = EF		0	0		
Emission Factor Source[1]	Control Efficiency Basis[2]	O***			
CO CONTROL DEVICE CODE[3]					
Avg. CO CONTROL EFFICIENCY[4] = CE		%		%	
CO EMISSIONS[5]		4.67 tons CO per yr		lbs per day	
PM2.5 EMISSION FACTOR (with units) = EF					
Emission Factor Source[1]	Control Efficiency Basis[2]				
FUEL PARAMETER (% ash or % sulfur) = FP		%		%	
PM2.5 CONTROL DEVICE CODE[3]					
Avg. PM2.5 CONTROL EFFICIENCY[4] = CE		%		%	
PM2.5 EMISSIONS[5]		tons PM2.5 per yr		lbs per day	
NH3 EMISSION FACTOR (with units) = EF					
Emission Factor Source[1]	Control Efficiency Basis[2]				
NH3 CONTROL DEVICE CODE[3]					
Avg. NH3 CONTROL EFFICIENCY[4] = CE		%		%	
NH3 EMISSIONS[5]		NA tons NH3 per yr		lbs per day	

***Emission factor in lbs/MMBtu equivalent to the concentration limit in the permit (Gas 9 ppm@15% O2, Oil 20 ppm@15%O2):

EF CO oil (lb/MMBtu) = K x COppm x Fd x 20.9/ (20.9 - %O2)

= $(7.267 \times 10^{-8}) \times 20 \times 9190 \times 20.9/(20.9 - 15)$

= 0.047 lb CO/MMBtu

1. AP-42; CEMS; ST = Stack Test; F = Federal factor (EPA standard factor); O = Other (describe on separate sheet; use subject to DEQ approval)
2. A = Tested (by EPA reference method); B = Tested (other); C = Meterail Balance; D = Design; O = Other (describe on separate sheet)
3. See 3-digit control device codes listed in appendix.
4. Note control efficiency will be zero if there is no control device OR the emission factor accounts for controls (i.e. EF is identified to be "with controls")
5. Annual Emissions = ANNUAL THRUPUT x EF x FP x (1/2000) x (100-CE)/100; Ozone Emissions = DAILY THRUPUT x EF x FP x (100-CE)/100

2014 EMISSIONS CALCULATIONS
OPTION I: EMISSION FACTOR METHOD

REGISTRATION # 40989 *STACK NO:* 6 *POINT NO.:* 6 *SEGMENT NO.:* 1 *SCC NO.:* 10500106

		ANNUAL		PEAK OZONE SEASON (JUNE, JULY, AUGUST)	
THRUPUT (with units)		1.10 MMcf		0.10 MMcf	
NO. OPERATING DAYS		365 days		92 days	
NO. OPERATING HOURS PER DAY		0.31 hours		0.111 hours	
DAILY THRUPUT (with units) = Thruput / days		NA		0.00109 MMcf/day	
VOC EMISSION FACTOR (with units) = EF		0.0636 lbs/MMBtu		0.1 lbs/MMBtu	
Emission Factor Source[1]	Control Efficiency Basis[2]	O*		O*	
VOC CONTROL DEVICE CODE[3]					
Avg. VOC CONTROL EFFICIENCY[4] = CE		%		%	
VOC EMISSIONS[5]		0.04 tons VOC per yr		0.1 lbs VOC per day	
NOx EMISSION FACTOR (with units) = EF		0.132 lbs/MMBtu		0.132 lbs/MMBtu	
Emission Factor Source[1]	Control Efficiency Basis[2]	O*		O*	
NOx CONTROL DEVICE CODE[3]					
Avg. NOx CONTROL EFFICIENCY[4] = CE		%		%	
NOx EMISSIONS		0.07 tons NOx per yr		0.1 lbs NOx per day	
SO2 EMISSION FACTOR (with units) = EF		0.1791 lbs/MMBtu			
Emission Factor Source[1]	Control Efficiency Basis[2]	O*			
FUEL PARAMETER (% ash or % sulfur) = FP		%		%	
SO2 CONTROL DEVICE CODE[3]					
Avg. SO2 CONTROL EFFICIENCY[4] = CE		%		%	
SO2 EMISSIONS[5]		0.10 tons SO2 per yr		lbs SO2 per day	
PM10 EMISSION FACTOR (with units) = EF		0.0318 lbs/MMBtu			
Emission Factor Source[1]	Control Efficiency Basis[2]	O*			
FUEL PARAMETER (% ash or % sulfur) = FP		%		%	
PM10 CONTROL DEVICE CODE[3]					
Avg. PM10 CONTROL EFFICIENCY[4] = CE		%		%	
PM10 EMISSIONS[5]		0.02 tons PM10 per yr		lbs PM10 per day	
PB EMISSION FACTOR (with units) = EF					
Emission Factor Source[1]	Control Efficiency Basis[2]				
PB CONTROL DEVICE CODE[3]					
Avg. PB CONTROL EFFICIENCY[4] = CE		%		%	
PB EMISSIONS[5]		tons PB per yr		lbs PB per day	

*Emission rates and factors used are from the permit application

1. AP-42; CEMS; ST = Stack Test; F = Federal factor (EPA standard factor); O = Other (describe on separate sheet; use subject to DEQ approval)
2. A = Tested (by EPA reference method); B = Tested (other); C = Meterail Balance; D = Design; O = Other (describe on separate sheet)
3. See 3-digit control device codes listed in appendix.
4. Note control efficiency will be zero if there is no control device OR the emission factor accounts for controls (i.e. EF is identified to be "with controls")
5. Annual Emissions = ANNUAL THRUPUT x EF x FP x (1/2000) x (100-CE)/100; Ozone Emissions = DAILY THRUPUT x EF x FP x (100-CE)/100

2014 EMISSIONS CALCULATIONS
OPTION I: EMISSION FACTOR METHOD

REGISTRATION # 40989 *STACK NO:* 6 *POINT NO.:* 6 *SEGMENT NO.:* 1 *SCC NO.:* 10500106

		ANNUAL		PEAK OZONE SEASON (JUNE, JULY, AUGUST)	
THRUPUT (with units)		1.10 MMcf			
NO. OPERATING DAYS		365 days		days	
NO. OPERATING HOURS PER DAY		0.31 hours		hours	
DAILY THRUPUT (with units) = Thruput / days		NA			
TRS EMISSION FACTOR (with units) = EF					
Emission Factor Source[1]	Control Efficiency Basis[2]				
TRS CONTROL DEVICE CODE[3]					
Avg. TRS CONTROL EFFICIENCY[4] = CE		%		%	
TRS EMISSIONS[5]		NA tons TRS per yr		lbs per day	
TNMOC EMISSION FACTOR (with units) = EF					
Emission Factor Source[1]	Control Efficiency Basis[2]				
TNMOC CONTROL DEVICE CODE[3]					
Avg. TNMOC CONTROL EFFICIENCY[4] = CE		%		%	
TNMOC EMISSIONS[5]		NA tons TNMOC per yr		lbs per day	
CO EMISSION FACTOR (with units) = EF		0.12 lbs/MMBtu			
Emission Factor Source[1]	Control Efficiency Basis[2]	O*			
CO CONTROL DEVICE CODE[3]					
Avg. CO CONTROL EFFICIENCY[4] = CE		%		%	
CO EMISSIONS[5]		0.067 tons CO per yr		lbs per day	
PM2.5 EMISSION FACTOR (with units) = EF					
Emission Factor Source[1]	Control Efficiency Basis[2]				
FUEL PARAMETER (% ash or % sulfur) = FP		%		%	
PM2.5 CONTROL DEVICE CODE[3]					
Avg. PM2.5 CONTROL EFFICIENCY[4] = CE		%		%	
PM2.5 EMISSIONS[5]		tons PM2.5 per yr		lbs per day	
NH3 EMISSION FACTOR (with units) = EF					
Emission Factor Source[1]	Control Efficiency Basis[2]				
NH3 CONTROL DEVICE CODE[3]					
Avg. NH3 CONTROL EFFICIENCY[4] = CE		%		%	
NH3 EMISSIONS[5]		NA tons NH3 per yr		lbs per day	

*Emission rates and factors used are from the permit application

1. AP-42; CEMS; ST = Stack Test; F = Federal factor (EPA standard factor); O = Other (describe on separate sheet; use subject to DEQ approval)
2. A = Tested (by EPA reference method); B = Tested (other); C = Meterail Balance; D = Design; O = Other (describe on separate sheet)
3. See 3-digit control device codes listed in appendix.
4. Note control efficiency will be zero if there is no control device OR the emission factor accounts for controls (i.e. EF is identified to be "with controls")
5. Annual Emissions = ANNUAL THRUPUT x EF x FP x (1/2000) x (100-CE)/100; Ozone Emissions = DAILY THRUPUT x EF x FP x (100-CE)/100

2014 EMISSIONS CALCULATIONS
OPTION I: EMISSION FACTOR METHOD

REGISTRATION # 40989 *STACK NO:* 7 *POINT NO.:* 7 *SEGMENT NO.:* 1 *SCC NO.:* 10500106

		ANNUAL		PEAK OZONE SEASON (JUNE, JULY, AUGUST)	
THRUPUT (with units)		1.40 MMcf		0.10 MMcf	
NO. OPERATING DAYS		365 days		92 days	
NO. OPERATING HOURS PER DAY		0.39 hours		0.11 hours	
DAILY THRUPUT (with units) = Thruput / days		NA		0.001 MMcf/day	
VOC EMISSION FACTOR (with units) = EF		0.0636 lbs/MMBtu		0.1 lbs/MMBtu	
Emission Factor Source[1]	Control Efficiency Basis[2]	O*		O*	
VOC CONTROL DEVICE CODE[3]					
Avg. VOC CONTROL EFFICIENCY[4] = CE		%		%	
VOC EMISSIONS[5]		0.05 tons VOC per yr		0.1 lbs VOC per day	
NOx EMISSION FACTOR (with units) = EF		0.132 lbs/MMBtu		0.132 lbs/MMBtu	
Emission Factor Source[1]	Control Efficiency Basis[2]	O*		O*	
NOx CONTROL DEVICE CODE[3]					
Avg. NOx CONTROL EFFICIENCY[4] = CE		%		%	
NOx EMISSIONS		0.09 tons NOx per yr		0.1 lbs NOx per day	
SO2 EMISSION FACTOR (with units) = EF		0.1791 lbs/MMBtu			
Emission Factor Source[1]	Control Efficiency Basis[2]	O*			
FUEL PARAMETER (% ash or % sulfur) = FP		%		%	
SO2 CONTROL DEVICE CODE[3]					
Avg. SO2 CONTROL EFFICIENCY[4] = CE		%		%	
SO2 EMISSIONS[5]		0.13 tons SO2 per yr		lbs SO2 per day	
PM10 EMISSION FACTOR (with units) = EF		0.0318 lbs/MMBtu			
Emission Factor Source[1]	Control Efficiency Basis[2]	O*			
FUEL PARAMETER (% ash or % sulfur) = FP		%		%	
PM10 CONTROL DEVICE CODE[3]					
Avg. PM10 CONTROL EFFICIENCY[4] = CE		%		%	
PM10 EMISSIONS[5]		0.02 tons PM10 per yr		lbs PM10 per day	
PB EMISSION FACTOR (with units) = EF					
Emission Factor Source[1]	Control Efficiency Basis[2]				
PB CONTROL DEVICE CODE[3]					
Avg. PB CONTROL EFFICIENCY[4] = CE		%		%	
PB EMISSIONS[5]		tons PB per yr		lbs PB per day	

*Emission rates and factors used are from the permit application

1. AP-42; CEMS; ST = Stack Test; F = Federal factor (EPA standard factor); O = Other (describe on separate sheet; use subject to DEQ approval)
2. A = Tested (by EPA reference method); B = Tested (other); C = Meterail Balance; D = Design; O = Other (describe on separate sheet)
3. See 3-digit control device codes listed in appendix.
4. Note control efficiency will be zero if there is no control device OR the emission factor accounts for controls (i.e. EF is identified to be "with controls")
5. Annual Emissions = ANNUAL THRUPUT x EF x FP x (1/2000) x (100-CE)/100; Ozone Emissions = DAILY THRUPUT x EF x FP x (100-CE)/100

2014 EMISSIONS CALCULATIONS
OPTION I: EMISSION FACTOR METHOD

REGISTRATION # 40989 *STACK NO:* 7 *POINT NO.:* 7 *SEGMENT NO.:* 1 *SCC NO.:* 10500106

		ANNUAL		PEAK OZONE SEASON (JUNE, JULY, AUGUST)	
THRUPUT (with units)		1.40 MMcf			
NO. OPERATING DAYS		365 days		days	
NO. OPERATING HOURS PER DAY		0.39 hours		hours	
DAILY THRUPUT (with units) = Thruput / days		NA			
TRS EMISSION FACTOR (with units) = EF					
Emission Factor Source[1]	Control Efficiency Basis[2]				
TRS CONTROL DEVICE CODE[3]					
Avg. TRS CONTROL EFFICIENCY[4] = CE		%		%	
TRS EMISSIONS[5]		NA tons TRS per yr		lbs per day	
TNMOC EMISSION FACTOR (with units) = EF					
Emission Factor Source[1]	Control Efficiency Basis[2]				
TNMOC CONTROL DEVICE CODE[3]					
Avg. TNMOC CONTROL EFFICIENCY[4] = CE		%		%	
TNMOC EMISSIONS[5]		NA tons TNMOC per yr		lbs per day	
CO EMISSION FACTOR (with units) = EF		0.12 lbs/MMBtu			
Emission Factor Source[1]	Control Efficiency Basis[2]	O*			
CO CONTROL DEVICE CODE[3]					
Avg. CO CONTROL EFFICIENCY[4] = CE		%		%	
CO EMISSIONS[5]		0.086 tons CO per yr		lbs per day	
PM2.5 EMISSION FACTOR (with units) = EF					
Emission Factor Source[1]	Control Efficiency Basis[2]				
FUEL PARAMETER (% ash or % sulfur) = FP		%		%	
PM2.5 CONTROL DEVICE CODE[3]					
Avg. PM2.5 CONTROL EFFICIENCY[4] = CE		%		%	
PM2.5 EMISSIONS[5]		tons PM2.5 per yr		lbs per day	
NH3 EMISSION FACTOR (with units) = EF					
Emission Factor Source[1]	Control Efficiency Basis[2]				
NH3 CONTROL DEVICE CODE[3]					
Avg. NH3 CONTROL EFFICIENCY[4] = CE		%		%	
NH3 EMISSIONS[5]		NA tons NH3 per yr		lbs per day	

*Emission rates and factors used are from the permit application

1. AP-42; CEMS; ST = Stack Test; F = Federal factor (EPA standard factor); O = Other (describe on separate sheet; use subject to DEQ approval)
2. A = Tested (by EPA reference method); B = Tested (other); C = Meterall Balance; D = Design; O = Other (describe on separate sheet)
3. See 3-digit control device codes listed in appendix.
4. Note control efficiency will be zero if there is no control device OR the emission factor accounts for controls (i.e. EF is identified to be "with controls")
5. Annual Emissions = ANNUAL THRUPUT x EF x FP x (1/2000) x (100-CE)/100; Ozone Emissions = DAILY THRUPUT x EF x FP x (100-CE)/100

2014 EMISSIONS CALCULATIONS
OPTION I: EMISSION FACTOR METHOD

REGISTRATION # 40989 *STACK NO:* 8 *POINT NO.:* 8 *SEGMENT NO.:* 1 *SCC NO.:* 20300101

		ANNUAL		PEAK OZONE SEASON (JUNE, JULY, AUGUST)	
THRUPUT (with units)		0.2 Mgals		0.0 Mgals	
NO. OPERATING DAYS		19 days		5 days	
NO. OPERATING HOURS PER DAY		0.5 hours		0.5 hours	
DAILY THRUPUT (with units) = Thruput / days		NA		0 Mgals/day	
VOC EMISSION FACTOR (with units) = EF		0.054 lbs/hr		0.1 lbs/hr	
Emission Factor Source[1]	Control Efficiency Basis[2]	O*		O*	
VOC CONTROL DEVICE CODE[3]					
Avg. VOC CONTROL EFFICIENCY[4] = CE		%		%	
VOC EMISSIONS[5]		0.00 tons VOC per yr		0.0 lbs VOC per day	
NOx EMISSION FACTOR (with units) = EF		8.102 lbs/hr		8.102 lbs/hr	
Emission Factor Source[1]	Control Efficiency Basis[2]	O*		O*	
NOx CONTROL DEVICE CODE[3]					
Avg. NOx CONTROL EFFICIENCY[4] = CE		%		%	
NOx EMISSIONS		0.04 tons NOx per yr		4.2 lbs NOx per day	
SO2 EMISSION FACTOR (with units) = EF		1.273 lbs/hr			
Emission Factor Source[1]	Control Efficiency Basis[2]	O*			
FUEL PARAMETER (% ash or % sulfur) = FP		%		%	
SO2 CONTROL DEVICE CODE[3]					
Avg. SO2 CONTROL EFFICIENCY[4] = CE		%		%	
SO2 EMISSIONS[5]		0.01 tons SO2 per yr		lbs SO2 per day	
PM10 EMISSION FACTOR (with units) = EF		0.1157 lbs/hr			
Emission Factor Source[1]	Control Efficiency Basis[2]	O*			
FUEL PARAMETER (% ash or % sulfur) = FP		%		%	
PM10 CONTROL DEVICE CODE[3]					
Avg. PM10 CONTROL EFFICIENCY[4] = CE		%		%	
PM10 EMISSIONS[5]		0.00 tons PM10 per yr		lbs PM10 per day	
PB EMISSION FACTOR (with units) = EF					
Emission Factor Source[1]	Control Efficiency Basis[2]				
PB CONTROL DEVICE CODE[3]					
Avg. PB CONTROL EFFICIENCY[4] = CE		%		%	
PB EMISSIONS[5]		tons PB per yr		lbs PB per day	

*Emission rates and factors used are from the permit application

1. AP-42; CEMS; ST = Stack Test; F = Federal factor (EPA standard factor); O = Other (describe on separate sheet; use subject to DEQ approval)
2. A = Tested (by EPA reference method); B = Tested (other); C = Meterail Balance; D = Design; O = Other (describe on separate sheet)
3. See 3-digit control device codes listed in appendix.
4. Note control efficiency will be zero if there is no control device OR the emission factor accounts for controls (i.e. EF is identified to be "with controls")
5. Annual Emissions = ANNUAL THRUPUT x EF x FP x (1/2000) x (100-CE)/100; Ozone Emissions = DAILY THRUPUT x EF x FP x (100-CE)/100

Old Dominion Electric Cooperative
Louisa Generation Facility
CY2014 Emission Statement

EMISSIONS CALCULATIONS
Combustion Turbines

Emission Unit	Pollutant	Hours of Operation Annual (hours)	Hours of Operation Ozone Season (hours)	Ozone Season (# days)	Emission Factor	EF Units	Reference	Emissions Annual (tons/yr)	Emissions Ozone Season (lbs/day)
1/1/2012	NOx	196.9	22.9	5			CEMS[1]	2.54	80.4
	SO2	196.9					O[2]	0.06	
	CO	196.9					CEMS[1]	5.23	
	PM10	196.9			10	lbs/hr	O[4]	0.98	
	VOC	196.9	22.9	5	2.2	lbs/hr	O[4]	0.22	10.1
EU1 - Oil	NOx	94.4	0.0	0			CEMS[1]	5.20	0.0
	SO2	94.4					O[2]	0.84	
	CO	94.4					CEMS[1]	0.89	
	PM10	94.4			21	lbs/hr	O[4]	0.99	
	VOC	94.4	0.0	0	5.5	lbs/hr	O[4]	0.26	0.0
	Pb	94.4			0.01525	lbs/hr	O[4]	0.00	
EU2 - Gas	NOx	137.6	13.7	2			CEMS[1]	1.92	110.0
	SO2	137.6					O[2]	0.06	
	CO	137.6					CEMS[1]	3.74	
	PM10	137.6			10	lbs/hr	O[4]	0.69	
	VOC	137.6	13.7	2	2.2	lbs/hr	O[4]	0.15	15.1
EU2 - Oil	NOx	97.6	0.0	0			CEMS[1]	5.48	0.0
	SO2	97.6					O[2]	0.86	
	CO	97.6					CEMS[1]	1.18	
	PM10	97.6			21	lbs/hr	O[4]	1.02	
	VOC	97.6	0.0	0	5.5	lbs/hr	O[4]	0.27	0.0
	Pb	97.6			0.01525	lbs/hr	O[4]	0.00	
EU3 - Gas	NOx	121.9	13.4	2			CEMS[1]	1.70	108.0
	SO2	121.9					O[2]	0.06	
	CO	121.9					CEMS[1]	1.86	
	PM10	121.9			10	lbs/hr	O[4]	0.61	
	VOC	121.9	13.4	2	2.2	lbs/hr	O[4]	0.13	14.7
EU3 - Oil	NOx	114.7	0.0	0			CEMS[1]	6.32	0.0
	SO2	114.7					O[2]	0.96	
	CO	114.7					CEMS[1]	0.73	
	PM10	114.7			21	lbs/hr	O[4]	1.20	
	VOC	114.7	0.0	0	5.5	lbs/hr	O[4]	0.32	0.0
	Pb	114.7			0.01525	lbs/hr	O[4]	0.00	

2014 EMISSIONS CALCULATIONS
OPTION I: EMISSION FACTOR METHOD

REGISTRATION # 40989 *STACK NO:* 8 *POINT NO.:* 8 *SEGMENT NO.:* 1 *SCC NO.:* 20300101

			ANNUAL		PEAK OZONE SEASON (JUNE, JULY, AUGUST)	
THRUPUT (with units)		0.20 Mgals				
NO. OPERATING DAYS		19 days			days	
NO. OPERATING HOURS PER DAY		0.5 hours			hours	
DAILY THRUPUT (with units) = Thruput / days		NA				
TRS EMISSION FACTOR (with units) = EF						
Emission Factor Source[1]	Control Efficiency Basis[2]					
TRS CONTROL DEVICE CODE[3]						
Avg. TRS CONTROL EFFICIENCY[4] = CE		%			%	
TRS EMISSIONS[5]		NA tons TRS per yr			lbs per day	
TNMOC EMISSION FACTOR (with units) = EF						
Emission Factor Source[1]	Control Efficiency Basis[2]					
TNMOC CONTROL DEVICE CODE[3]						
Avg. TNMOC CONTROL EFFICIENCY[4] = CE		%			%	
TNMOC EMISSIONS[5]		NA tons TNMOC per yr			lbs per day	
CO EMISSION FACTOR (with units) = EF		2.0834 lbs/hr				
Emission Factor Source[1]	Control Efficiency Basis[2]	O*				
CO CONTROL DEVICE CODE[3]						
Avg. CO CONTROL EFFICIENCY[4] = CE		%			%	
CO EMISSIONS[5]		0.010 tons CO per yr			lbs per day	
PM2.5 EMISSION FACTOR (with units) = EF						
Emission Factor Source[1]	Control Efficiency Basis[2]					
FUEL PARAMETER (% ash or % sulfur) = FP		%			%	
PM2.5 CONTROL DEVICE CODE[3]						
Avg. PM2.5 CONTROL EFFICIENCY[4] = CE		%			%	
PM2.5 EMISSIONS[5]		tons PM2.5 per yr			lbs per day	
NH3 EMISSION FACTOR (with units) = EF						
Emission Factor Source[1]	Control Efficiency Basis[2]					
NH3 CONTROL DEVICE CODE[3]						
Avg. NH3 CONTROL EFFICIENCY[4] = CE		%			%	
NH3 EMISSIONS[5]		NA tons NH3 per yr			lbs per day	

*Emission rates and factors used are from the permit application

1. AP-42; CEMS; ST = Stack Test; F = Federal factor (EPA standard factor); O = Other (describe on separate sheet; use subject to DEQ approval)
2. A = Tested (by EPA reference method); B = Tested (other); C = Meterall Balance; D = Design; O = Other (describe on separate sheet)
3. See 3-digit control device codes listed in appendix.
4. Note control efficiency will be zero if there is no control device OR the emission factor accounts for controls (i.e. EF is identified to be "with controls")
5. Annual Emissions = ANNUAL THRUPUT x EF x FP x (1/2000) x (100-CE)/100; Ozone Emissions = DAILY THRUPUT x EF x FP x (100-CE)/100

Old Dominion Electric Cooperative
Louisa Generation Facility
CY2014 Emission Statement

EMISSIONS CALCULATIONS

Emission Unit	Pollutant	Hours of Operation: Annual (hours)	Hours of Operation: Ozone Season (hours)	Ozone Season (# days)	Emission Factor	EF Units	Reference	Emissions: Annual (tons/yr)	Emissions: Ozone Season (lbs/day)
EU4 - Gas	NOx	145.9	8.0	2			CEMS[1]	2.06	87.0
	SO2	145.9					O[2]	0.06	
	CO	145.9					CEMS[1]	2.72	
	PM10	145.9			10	lbs/hr	O[4]	0.73	
	VOC	145.9	8.0	2	2.2	lbs/hr	O[4]	0.16	8.8
EU4 - Oil	NOx	108.8	0.0	0			CEMS[1]	6.48	0.0
	SO2	108.8					O[2]	0.82	
	CO	108.8					CEMS[1]	1.15	
	PM10	108.8			21	lbs/hr	O[4]	1.14	
	VOC	108.8	0.0	0	5.5	lbs/hr	O[4]	0.30	0.0
	Pb	108.8			0.01525	lbs/hr	O[4]	0.00	
EU5 - Gas	NOx	567.4	173.2	27			CEMS[1]	14.47	266.2
	SO2	567.4					O[2]	0.28	
	CO*	1027045.8					O[3]	9.58	
	PM10	567.4			18	lbs/hr	O[4]	5.11	
	VOC	567.4	173.2	27	3.2	lbs/hr	O[4]	0.91	20.5
EU5 - Oil	NOx	103.3	0.0	0			CEMS[1]	12.07	0.0
	SO2	103.3					O[2]	1.76	
	CO*	213810.1					O[3]	4.67	
	PM10	103.3			36	lbs/hr	O[4]	1.86	
	VOC	103.3	0.0	0	8	lbs/hr	O[4]	0.41	0.0
	Pb	103.3			0.015	lbs/hr	O[4]	0.00	

*Utilize Heat input (MMBtu)

Old Dominion Electric Cooperative
Louisa Generation Facility
CY2014 Emission Statement

EMISSIONS CALCULATIONS

Natural Gas Heaters

Emission Unit	Pollutant	Fuel Throughput		Heat Input*		Ozone Season (# days)**	Emission Factor	EF Units	Reference	Emissions	
		Annual (MMcf)	Ozone Season (MMcf)	Annual (MMBtu)	Ozone Season (MMBtu)					Annual (tons/yr)	Ozone Season (lbs/day)
EU6	NOx	1.1	0.1	1122.0	102.0	92	0.132	lbs/MMBtu	O[4]	0.074	0.1464
	SO2	1.1	0.1	1122.0	102.0		0.1791	lbs/MMBtu	O[4]	0.100	
	CO	1.1	0.1	1122.0	102.0		0.12	lbs/MMBtu	O[4]	0.067	
	PM10	1.1	0.1	1122.0	102.0		0.0318	lbs/MMBtu	O[4]	0.018	
	VOC	1.1	0.1	1122.0	102.0	92	0.0636	lbs/MMBtu	O[4]	0.036	0.0705
EU7	NOx	1.4	0.1	1428.0	102.0	92	0.132	lbs/MMBtu	O[4]	0.094	0.1464
	SO2	1.4	0.1	1428.0	102.0		0.1791	lbs/MMBtu	O[4]	0.128	
	CO	1.4	0.1	1428.0	102.0		0.12	lbs/MMBtu	O[4]	0.086	
	PM10	1.4	0.1	1428.0	102.0		0.0318	lbs/MMBtu	O[4]	0.023	
	VOC	1.4	0.1	1428.0	102.0	92	0.0636	lbs/MMBtu	O[4]	0.045	0.0705

*Heat Input based on Fuel Throughput (MMcf) x Average HHV (MMBtu/MMcf)

**Assume maximum # days in the ozone season)

Emergency Diesel Fire Pump

Emission Unit	Pollutant	Hours of Operation		Ozone Season (# days)*	Emission Factor	EF Units	Reference	Emissions	
		Annual (hours)	Ozone Season (hours)					Annual (tons/yr)	Ozone Season (lbs/day)
EU8	NOx	9.7	2.6	5	8.102	lbs/hr	O[4]	0.039	4.200
	SO2	9.7	2.6		1.273	lbs/hr	O[4]	0.006	
	CO	9.7	2.6		2.0834	lbs/hr	O[4]	0.010	
	PM10	9.7	2.6		0.1157	lbs/hr	O[4]	0.001	
	VOC	9.7	2.6	5	0.054	lbs/hr	O[4]	0.000	0.03

*Assume 0.5 hour run

[1] Data based upon CEMS data calculated and substituted as required by permit.
[2] Data based upon Part 75, Appendix D calculations, performed by DAHS.
[3] Data based upon emission factor equiv to permit limit, calculation performed by DAHS .
[4] Data based upon information submitted in permit application.

Facility Total

Pollutant	Emissions	
	Annual (tons/yr)	Ozone Season (lbs/day)
NOx	58.45	656.1
SO2	5.99	
CO	31.91	
PM10	14.37	
VOC	3.21	69.40
Pb	0.00	

ATTACHMENT B

Minor NSR Permit dated October 27, 2009, as amended February 26, 2010 and June 16, 2015

COMMONWEALTH of VIRGINIA

Molly Joseph Ward
Secretary of Natural Resources

DEPARTMENT OF ENVIRONMENTAL QUALITY
NORTHERN REGIONAL OFFICE
13901 Crown Court, Woodbridge, Virginia 22193-1453
(703) 583-3800 Fax (703) 583-3821
www.deq.virginia.gov

David K. Paylor
Director

Thomas A. Faha
Regional Director

June 16, 2015

Mr. D. Richard Beam
Senior Vice President – Power Supply
Old Dominion Electric Cooperative
4201 Dominion Boulevard
Glen Allen, VA 23060

Location: Louisa County
Registration No.: 40989
Facility ID No. 51-109-00050

Dear Mr. Beam:

Attached is a minor amendment to your new source review permit document dated October 27, 2009, as amended February 26, 2010, to modify and operate stationary gas turbines in accordance with the provisions of the Virginia State Air Pollution Control Board's Regulations for the Control and Abatement of Air Pollution. <u>This amended permit supersedes your permit document dated October 27, 2009, as amended February 26, 2010.</u>

The Department of Environmental Quality (DEQ) deemed the application complete on June 30, 2014, and has determined that the application meets the requirements of 9 VAC 5-80-1280 for a minor amendment to a new source review permit.

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

The permit approval to modify and operate shall not relieve Old Dominion Electric Cooperative of the responsibility to comply with all other local, state, and federal permit regulations.

The Board's Regulations as contained in Title 9 of the Virginia Administrative Code 5-170-200 provide that you may request a formal hearing from this case decision by filing a petition with the Board within 30 days after this case decision notice was mailed or delivered to you. 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 document 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 document 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 me, by phone at (703) 583-3928 or e-mail at james.lafratta@deq.virginia.gov.

Sincerely,

James B. LaFratta

James B. LaFratta
Regional Air Permit Manager

TAF/JBL/40989 mNSR Permit Amendment (6-16-2015)

Attachment: Permit

cc: David N. Smith, Old Dominion Electric Cooperative (electronic copy)
Manager/Inspector, NRO Air Compliance (electronic copy)

COMMONWEALTH of VIRGINIA

Molly Joseph Ward
Secretary of Natural Resources

DEPARTMENT OF ENVIRONMENTAL QUALITY
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David K. Paylor
Director

Thomas A. Faha
Regional Director

STATIONARY SOURCE PERMIT TO MODIFY AND OPERATE
This permit includes designated equipment subject to New Source Performance Standards (NSPS)

<u>This amended permit supersedes your permit document dated October 27, 2009, as amended February 26, 2010.</u>

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

Old Dominion Electric Cooperative
4201 Dominion Boulevard
Glen Allen, VA 23060
Registration No.: 40989

is authorized to modify and operate

five (5) simple cycle combustion turbines and associated auxiliary equipment

located at

Louisa Generation Facility
3352 Klockner Road
Gordonsville, VA 22942
(Louisa County)

in accordance with the Conditions of this permit.

Approved on October 27, 2009
Amended on February 26, 2010
Amended on June 16, 2015

for Thomas A. Faha
Regional Director

Permit document consists of 24 pages.
Permit Conditions 1 to 44.

INTRODUCTION

This permit approval is based on the permit applications dated:

- June 27, 2014;
- January 29, 2010;
- July 13, 2009 (including supplemental information dated August 26, 2009, September 14, 2009, and October 19, 2009);
- August 3, 2004 (including supplemental information dated September 21, 2004, June 21, 2005, February 27, 2006, August 29, 2006, September 29, 2006, and December 20, 2006;
- Permit application amendments dated April 15, 2002, April 26, 2002, May 13, 2002, July 25, 2002, August 20, 2002, November 25, 2002, December 4, 2002, and email dated February 10, 2003;
- February 25, 2000 (including amendment information dated October 20, 2000, January 24, 2001, March 23, 2001 and May 3, 2001; and
- Correspondence dated April 10, 2000, April 14, 2000, June 5, 2000, June 16, 2000, February 28, 2001, and September 7, 2001.

Any changes in the permit application specifications or any existing facilities which alter the impact of the facility on air quality may require a permit. Failure to obtain such a permit prior to construction may result in enforcement action. In addition, this facility may be subject to additional applicable requirements not listed in this permit.

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

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

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

Equipment List – Equipment at this facility consists of the following:

Equipment permitted prior to the date of this permit:			
Reference No.	**Equipment Description**	**Rated Capacity**	**Delegated Federal Requirements**
EU 1-4	Four (4) GE Model PG7121 (EA) simple cycle, dual fuel, combustion turbines	901 MMBtu/hr[1] (heat input when combusting natural gas) 967 MMBtu/hr[1] (heat input when combusting No. 2 distillate fuel oil) (each unit)	40 CFR Part 60 Subpart GG
EU 5	One (1) GE Model PG7241S (FA) simple cycle, dual fuel, combustion turbines	1,624 MMBtu/hr[1] (heat input when combusting natural gas) 1,820 MMBtu/hr[1] (heat input when combusting No. 2 distillate fuel oil)	40 CFR Part 60 Subpart GG
EU 6 - 7	Two (2) natural gas fuel pipeline heaters	9.948 MMBtu/hr (heat input) (each unit)	None
EU 8	One (1) emergency diesel fire pump	2.59 MMBtu/hr (heat input)	None
TNK 1-2	Two (2) fixed roof above ground storage tanks for No. 2 distillate fuel oil	1,000,000 gallons (nominal storage capacity) (each unit)	None

Equipment permitted prior to the date of this permit:			
Reference No.	**Equipment Description**	**Rated Capacity**	**Delegated Federal Requirements**
TNK 3	One (1) distillate fuel oil storage tank for the fire pump (EU 8)	250 gallons (nominal storage capacity)	None

[1] When operated at 100 percent base load at atmospheric conditions – temperature of 59°F, relative humidity of 60 percent and a pressure of 14.7 psia.

Specifications included in the above table are for informational purposes only and do not form enforceable terms or conditions of the permit.
(9 VAC 5-80-1180 D 3)

PROCESS REQUIREMENTS

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

2. **NOx Emission Controls: Auxiliary Equipment** – NOx emissions from each natural gas pipeline heater (Ref. No. EU 6-7) and the emergency diesel fire pump (Ref. No. EU 8) shall be controlled by the use of good combustion operating techniques. The natural gas fueled pipeline heaters and emergency diesel fire pump shall be provided with adequate access for inspection.
(9 VAC 5-80-1180 and 9 VAC 5-50-260)

3. **SO_2 Emission Controls** – Sulfur dioxide (SO_2) emissions from each CT (Ref. No. EU 1-5), natural gas pipeline heater (Ref. No. EU 6-7) and the emergency diesel fire pump (Ref. No. EU 8) shall be controlled by the use of low sulfur fuels.
(9 VAC 5-80-1180 and 9 VAC 5-50-260)

4. **PM_{10} Emission Controls** – Particulate matter (PM) emissions from each CT (Ref. No. EU 1-5), natural gas pipeline heater (Ref. No. EU 6-7) and the emergency diesel fire pump (Ref. No. EU 8) 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)

5. **VOC and CO Emission Controls** – Volatile organic compounds (VOC) and carbon monoxide (CO) emissions from each CT (Ref. No. EU 1-5), natural gas pipeline heater (Ref. No. EU 6-7) and the emergency diesel fire pump (Ref. No. EU 8) shall be controlled by the use of good combustion operating practices.
(9 VAC 5-80-1180 and 9 VAC 5-50-260)

OPERATING LIMITATIONS

6. **CTs' Operating Hours –**

   a. **GE (FA) CT (Ref. No. EU 5) Operating Hours:**

      i. When firing natural gas, the operation of the CT (Ref. No. EU 5) shall not exceed 1580 hours per year, calculated monthly as the sum of each consecutive twelve month period.

      ii. When firing No. 2 distillate fuel oil, the operation of the CT (Ref. No. EU 5) shall not exceed 138 hours per year, calculated monthly as the sum of each consecutive twelve month period.

      iii. See Condition 32.h for record keeping requirements to demonstrate compliance with this condition.

   b. **GE (EA) CTs (Ref. No. EU 1-4) Operating Hours:**

      i. When firing natural gas, the combined hours of operation of the CTs (Ref. No. EU 1-4) shall not exceed 6320 hours per year, calculated monthly as the sum of each consecutive twelve month period.

      ii. When firing No. 2 distillate fuel oil, the combined operation of the CTs (Ref. No. EU 1-4) shall not exceed 552 hours per year, calculated monthly as the sum of each consecutive twelve month period.

      iii. See Condition 32.h for record keeping requirements to demonstrate compliance with this condition.

   c. Except for start-up and shut-down conditions, fuel switching, re-tuning, scheduled and non-scheduled maintenance, each CT (Ref. No. EU 1-5) shall be operated at 60-100 percent of its base load.

   (9 VAC 5-80-1180)

7. **Fire Pump's Operating Hours** – The operation of the emergency diesel fire pump (Ref. No. EU 8) shall not exceed 52 hours per year, calculated monthly as the sum of each consecutive twelve month period. See Condition 32.h for record keeping requirements to demonstrate compliance with this condition.
(9 VAC 5-80-1180)

8. **Pipeline Heaters' Fuel Throughput** – The combined natural gas consumption of the two natural gas fuel pipeline heaters (Ref. No. EU 6-7) shall not exceed 33 x 10^6 cubic feet per year, calculated monthly as the sum of each consecutive twelve month period. See Condition 32.h for record keeping requirements to demonstrate compliance with this condition.
(9 VAC 5-80-1180)

9. **Fuel** – The approved fuels for the CTs (Ref. No. EU 1-5) are natural gas (primary fuel) and No. 2 distillate fuel oil (back-up fuel). The approved fuel for the pipeline heaters (Ref. No. EU 6-7) is natural gas. The approved fuel for the emergency fire pump (Ref. No. EU 8) is No. 2 distillate fuel oil.

   Distillate oil is defined as fuel oil that meets the specifications for Fuel Oil Numbers 1 or 2 under American Society for Testing and Materials, ASTM D396, "Standard Specification for Fuel Oils", or other approved ASTM method, incorporated in 40 CFR 60 by reference. A change in fuel may require a permit to modify and operate.
   (9 VAC 5-80-1180)

10. **Natural Gas Fuel Specifications** – The maximum sulfur content of the natural gas to be burned in the CTs (Ref. No. EU 1-5) and the pipeline heaters (Ref. No. EU 6-7) 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 CTs and the pipeline heaters shall not exceed 2 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 with the individual monthly values for the preceding eleven months.
(9 VAC 5-80-1180)

11. **No. 2 Distillate Fuel Oil Specifications** – The maximum sulfur content of the No. 2 distillate fuel oil to be burned in the CTs (Ref. No. EU 1-5) shall not exceed 0.05% by weight.

    The maximum sulfur content of the No. 2 distillate fuel oil to be burned in the emergency diesel fire pump (Ref. No. EU 8) shall not exceed 0.5% by weight.
    (9 VAC 5-80-1180)

12. **Fuel Certification** – The permittee shall obtain a certification from the fuel supplier and/or fuel delivery company with each shipment of No. 2 distillate fuel oil. Each fuel supplier certification shall include the following:

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

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

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

    d. A statement that the distillate oil complies with the American Society for Testing and Materials specifications (ASTM D396) for numbers 1 or 2 fuel oil or other approved ASTM method, incorporated in 40 CFR 60 by reference; and,

    e. The actual sulfur content of the No. 2 distillate fuel oil, or a fuel sample and analysis independent of that used for certification may be used to determine fuel oil sulfur content.

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

13. **Fuel Tanks** – The two 1,000,000 gallons fixed-roof above ground storage tanks (Ref. No. EU TNK 1-2) shall be used to store only No. 2 distillate fuel oil.
    (9 VAC 5-80-1180)

14. **Requirements by Reference** – Except where this permit is more restrictive than the applicable requirement, the CTs (Ref. No. EU 1-5) 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)

15. **Testing/Monitoring Ports** – Upon request by the DEQ, the permitted facility shall be modified so as to allow for emissions testing and monitoring upon reasonable notice at any time, using appropriate methods. This includes modifying the facility such that volumetric flow rates and pollutant emission rates can be accurately determined by the applicable test methods and providing stack or duct that is free from cyclonic flow. Test ports shall be provided when requested at the appropriate locations.
    (9 VAC 5-50-30 F and 9 VAC 5-80-1180)

16. **Alternate Operating Scenario: Fuel Switching** – Fuel switching is limited to the following:

Event 1 – Automatic or Operator Initiated Fuel Switching from Pipeline Natural Gas to Fuel Oil: The period will begin when gas usage is first reduced for the purpose of switching to oil and end when oil consumption and water injection have stabilized.

Event 2 – Operator Initiated Fuel Switching from Fuel Oil to Pipeline Natural Gas: The period will begin when the turbine's work load is reduced for the purpose of switching to natural gas and end when oil usage ceases and the turbine is re-stabilized in Mode 6 for Dry Low NOx Burners.

Excess NOx Emissions – Excess NOx emissions from each CT (Ref. No. EU 1-5) shall be limited to no more than two 1-hour averaging periods for any fuel switching event, unless specifically authorized by DEQ for longer duration prior to the event. For each fuel switching event, the permittee shall:

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

b. The permittee has provided and shall maintain a general description of the procedures to be followed during periods of fuel switching to ensure that the best operational practices to minimize emissions will be adhered to and the duration of excess emissions will be minimized.

c. The description may be updated as needed by submitting such update to the Regional Air Compliance Manager of the DEQ's Northern Regional Office (NRO) within thirty days of implementation.

d. Excess emissions during the fuel switching procedure will be recorded and included in the quarterly Excess Emission Report required by Condition 33. The CEM data will be "flagged" to indicate that fuel switching took place.

All correspondence concerning this permit should be submitted to the following address:

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

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

EMISSION LIMITS

17. **Short-term Emission Limits: Natural Gas** – Short-term emissions from the operation of each CT (Ref. No. EU 1-5) while firing natural gas shall not exceed the limits specified below (except during start-up and shut-down as defined in Condition 19, fuel switching in accordance with Condition 16 and re-tuning in accordance with Condition 36):

    a. GE Model PG7241S (FA) CT (Ref. No. EU 5)

PM-10	18 lbs/hr
Nitrogen Oxides (as NO_2)	10.5 ppmvd @ 15% O_2 (1-hour average)
Nitrogen Oxides (as NO_2)	9.0 ppmvd @ 15% O_2 (30-day average)
Carbon Monoxide	9.0 ppmvd @ 15% O_2 (3-hour average)

    b. GE Model PG7121 (EA) CT (Ref. No. EU 1-4) – Each Unit

PM-10	10 lbs/hr
Nitrogen Oxides (as NO_2)	10.5 ppmvd @ 15% O_2 (1-hour average)
Nitrogen Oxides (as NO_2)	9.0 ppmvd @ 15% O_2 (30-day average)
Carbon Monoxide	25 ppmvd @ 15% O_2 (3-hour average)

    c. During fuel switching, as defined in Condition 16, the short-term combustion turbine emission limits for No. 2 distillate fuel oil contained in Condition 18 shall apply when switching from natural gas to fuel oil or from fuel oil to natural gas combustion. Excess emissions during fuel switching shall be any emissions above those specified in Condition 18.

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

18. **Short-term Emission Limits: Distillate Fuel Oil** – Short-term emissions from the operation of each CT (Ref. No. EU 1-5) while firing No. 2 distillate fuel oil shall not exceed the limits specified below (except during start-up, shut-down, fuel switching and re-tuning conditions).

    a. GE Model PG7241S (FA) CT (Ref. No. EU 5)

PM-10	36 lbs/hr
Nitrogen Oxides (as NO_2)	42* ppmvd @ 15% O_2 (1-hour average)
Carbon Monoxide	20 ppmvd @ 15% O_2 (3-hour average)

    b. GE Model PG7121 (EA) CT (Ref. No. EU 1-4) – Each Unit

PM-10	21 lbs/hr
Nitrogen Oxides (as NO_2)	42* ppmvd @ 15% O_2 (1-hour average)
Carbon Monoxide	20 ppmvd @ 15% O_2 (3-hour average)

*when fuel bound nitrogen (FBN) content values are ≤ 0.015%. For 0.015% < FBN ≤ 0.05%, the adjusted standard shall be determined, recorded and maintained upon each new fuel delivery by the following formula (if an adjusted NOx standard is desired by the permittee):

NOx Standard = (0.04*FBN) + 0.0042

where:

FBN = Fuel bound nitrogen content of the distillate fuel oil (percent by weight)

Note (1): 0.0042% = 42 ppm
Note (2): 0.05% is maximum FBN allowed in adjusting the NOx emission standard

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

19. **Start-up and Shut-down** – For the purposes of this permit, definitions of start-up and shut-down (as they relate to the CTs (Ref. No. EU 1-5)) are provided below:

    a. "Start-up" is defined as either the time from ignition to one hour after achieving Emissions Compliance Control Mode or as the period commencing with ignition of the unit and consisting of two hours of continuous emission monitoring system (CEMS) data, whichever has the shorter time interval. Emissions Compliance Control Mode is defined as Mode 6 or pre-mix combustion modes for the units, when combusting natural gas fuel. These modes are the low NOx control modes. When combusting fuel oil, the Emissions Compliance Control Mode is achieved when the water injection NOx control system is activated.

    b. "Shut-down" is defined as either the period of time from initiation of a turbine shut-down until ignition stops or as the period comprised of the final two hours of CEMS data prior to the time when no fuel is being combusted, whichever has the shorter time interval.

    (9 VAC 5-80-1180)

20. **CTs' Annual Emission Limits** – Total emissions from the combined operation of the five (5) CTs (Ref. No. EU 1-5) shall not exceed the limits specified below:

Carbon Monoxide	240.6 tons/year
Nitrogen Oxides (as NO_2)	245.1 tons/year

    The emission rates shall be calculated daily as the sum of each consecutive 365-day period. (9 VAC 5-80-1180 and 9 VAC 5-50-260)

21. **Facility-wide Annual Emission Limits** – Total emissions from the combined operation of all the emission sources at the Louisa Generation Facility (as referenced in the equipment table provided in the 'Introduction' section of this permit) shall not exceed the limits specified below:

Carbon Monoxide	242.7 tons/year
Nitrogen Oxides (as NO_2)	247.6 tons/year

    The emission rates shall be calculated daily as the sum of each consecutive 365-day period. (9 VAC 5-80-1180 and 9 VAC 5-50-260)

22. **Visible Emission Limit** – Visible emissions from each CT exhaust stack (Ref. No. EU 1-5) shall not exceed ten (10) percent opacity except during one 6-minute period in any one hour in which visible emissions shall not exceed twenty (20) percent opacity, as determined by EPA Method 9 (reference 40 CFR 60, Appendix A). This condition applies at all times except during start-up, shut-down and malfunction.
(9 VAC 5-80-1180 and 9 VAC 5-50-260)

EMISSION AND PARAMETER MONITORING

23. **CEMS/Monitoring Data Use** – At the discretion of the Board, the NOx and CO continuous emission monitoring systems (CEMS) required by this permit, the continuous monitoring data, and the quality assurance data shall be used to determine compliance with the NOx and CO 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)

24. **NOx CEMS** – CEMS shall be installed, maintained and operated to measure and record the emissions of nitrogen oxides from each CT's (Ref. No. EU 1-5) exhaust stack. An oxygen (O_2) monitor shall be co-located with each nitrogen oxide concentration monitor.

    The CEMS shall be installed, calibrated, maintained 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.

    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 NOx 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 40 CFR Part 75, Appendix B §2.2.3.f, no more than four (4) successive calendar quarters plus the allowable grace period allowed in 40 CFR Part 75 will elapse without performing a NOx and O_2 analyzer linearity check. As per 40 CFR Part 75, Appendix B §2.3.3.a.4, no more than eight (8) successive calendar quarters plus the allowable grace period allowed in 40 CFR Part 75 will elapse without performing a NOx CEMS relative accuracy test audit (RATA).
    (9 VAC 5-50-40, 9 VAC 5-50-50 and 9 VAC 5-50-410)

25. **CO CEMS** – CEMS shall be installed, maintained and operated to measure and record the concentration of CO from each GE Model PG7121 (EA) CT's exhaust stack (Ref. No. EU 1-4).

    The CO CEMS shall be installed, calibrated, maintained and operated in accordance with the performance specifications and test procedures (as applicable) identified in 40 CFR §60.13

and 40 CFR 60, Appendices B and F. Upon request by the DEQ, the source shall conduct performance tests.

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 60, Appendix F. A CO CEMS quality control program which meets the requirements of 40 CFR §60.13 and 40 CFR 60, Appendix F shall be implemented for all CO continuous monitoring systems.

The frequencies of the Cylinder Gas Audits (CGAs) and the Relative Accuracy Test Audits (RATAs) for the CO CEMS shall be as follows. The CO CEMS CGAs shall be performed using the same frequency allowed by 40 CFR Part 75, Appendix B for NOx Linearity Error tests. No more than four (4) successive calendar quarters plus the allowable grace period allowed in 40 CFR Part 75 will elapse without performing a CO CEMS CGA. The CO RATAs shall be performed using the same frequency allowed by 40 CFR Part 75 for the NOx CEMS RATA tests. No more than eight (8) successive calendar quarters plus the allowable grace period allowed in 40 CFR Part 75 will elapse without performing a CO CEMS RATA. CO CEMS data validation shall be as specified in 40 CFR §60.334(b)(2). A QA operating quarter shall be as defined in 40 CFR §72.2.
(9 VAC 5-50-40 and 9 VAC 5-50-50)

26. **CEMS Minimum Data Capture** – The NOx and CO CEMS required by this permit shall meet a minimum data capture of 90 percent of each CT's (Ref. No. EU 1-5, as applicable) 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 first - adding the most recent completed calendar month's total hours of valid CEMS data and total hours of unit operation to their respective monthly totals for the preceding eleven months, and then dividing the total hours of valid CEMS data in the twelve month period by the total hours of unit operation in the twelve month period to determine availability.
(9 VAC 5-50-40)

27. **NOx CEMS Failure** – In the event of a NOx CEMS failure, the permittee must either:

a. Use the maximum allowable hourly NOx emission rate (in lbs/10^6 Btu equivalent to the 1-hour average concentration limits listed in Conditions 17 and 18), 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 CEMS data for future emission calculations.

(9 VAC 5-50-40)

28. **CO CEMS Failure** – In the event of a CO CEMS failure, the permittee must use the maximum short-term CO emission rate (in lbs/10^6 Btu equivalent to the 3-hour average concentration limits listed in Conditions 17 and 18), for each hour of operation where CEMS data is not available. This data shall be included in the rolling 365-day emission summation. (9 VAC 5-50-40)

29. **Fuel Consumption Monitoring** – The permittee shall install a continuous monitoring system (CMS) to measure and record the flow rate of fuel combusted by each CT (Ref. No. EU 1-5) for each hour when the unit is combusting fuel. The CMS shall consist of an in-line fuel flowmeter, and automatically record the data with a data acquisition and handling system. These records shall be kept on file at the facility for the most current five year period.
(9 VAC 5-50-40, 9 VAC 5-50-410 and 9 VAC 5-80-1180)

30. **Natural Gas Sulfur Content Monitoring** – The permittee shall monitor the sulfur content of the natural gas being fired in each CT (Ref. No. EU 1-5), in accordance with 40 CFR Part 60, Subpart GG. ODEC's EPA approved custom fuel monitoring schedule is as follows:

    a. Analysis for fuel sulfur content of the natural gas shall be conducted using one of the total sulfur methods described in 40 CFR §60.335 (b)(10). Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than 0.4 weight percent (4000 ppmw), ASTM D4084-82 or 94, D5504-01, D6228-98, or Gas Processors Association Standard 2377-86 (all of which are incorporated by reference – see 40 CFR §60.17), which measure the major sulfur compounds, may be used.

    b. Sulfur monitoring shall be conducted twice monthly for twelve months. If this monitoring demonstrates compliance with allowable permit limits, then sulfur monitoring shall be conducted once per month for six months.

    c. If the monitoring required in Condition 30.b demonstrates consistent compliance with the fuel sulfur content allowable permit limits, sulfur monitoring shall be conducted once per quarter.

    d. The sulfur analyses required Conditions 30.b and 30.c shall be conducted during unit operating months only.

    e. Should any sulfur analysis required in Condition 30.b indicate noncompliance, the permittee shall notify the Regional Air Compliance Manager of the DEQ's NRO. Sulfur monitoring shall be conducted each day the CTs operate during the interim period when this custom schedule is being re-examined and those results may be submitted to show compliance.

    f. If there is a change in fuel supply, the permittee shall notify the Regional Air Compliance Manager of the DEQ's NRO of such change for re-examination of this custom 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 schedule is being re-examined.

g. 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 gaseous fuel combusted in a turbine if the gaseous fuel is demonstrated to meet the definition of natural gas in 40 CFR §60.331(u), regardless of whether an existing custom schedule approved by the Administrator for 40 CFR 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 the gaseous fuel, specifying that the maximum total sulfur content of the fuel is 20.0 grains/100 scf or less; or,

   ii. Representative fuel sampling data which show that the sulfur content of the gaseous fuel does not exceed 20 grains/100 scf. At a minimum, the amount of fuel sampling data shall be as specified in Section 2.3.1.4 or 2.3.2.4 of 40 CFR Part 75, Appendix D.

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 letters dated March 28, 2003 and July 9, 2004)

31. **No. 2 Distillate Fuel Oil's Nitrogen and Sulfur Content Monitoring** – The permittee shall sample the No. 2 distillate fuel oil storage tanks (Ref. No. TNK 1-2) that supply fuel oil to the CTs (Ref. No. EU 1-5), to determine the sulfur content on each occasion that fuel is transferred to the storage tanks from any other source or fuel vendor. For the purposes of this permit, an oil shipment/transfer is defined as a series of truck transport loads from a vendor's fuel oil tank(s) to each of the permittee's 1,000,000 gallon above ground storage tanks.

Fuel oil sulfur content shall be determined using ASTM D2880 or another approved, applicable ASTM method incorporated by reference in 40 CFR Part 60.

If the permittee claims an allowance for fuel bound nitrogen (see Condition 18 and/or if an F-value greater than zero is being or will be used by the permittee to calculate STD in 40 CFR §60.332), the permittee shall monitor the nitrogen content of the fuel combusted in the turbine in same fashion as for sulfur content required in this permit condition. The nitrogen content of the fuel shall be determined using methods described in §60.335(b)(9) or an EPA approved alternative procedure.

Records of 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 AND REPORTING

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

    a. Fuel records to demonstrate compliance with Conditions 9, 10, 11, 12, 30 and 31.

    b. Annual hours of operation for each CT (Ref. No. EU 1-5), calculated monthly as the sum of each consecutive twelve-month period, as required by Condition 6.

    c. Annual hours of operation for the emergency diesel fire pump (Ref. No. EU 8), calculated monthly as the sum of each consecutive twelve-month period, as required by Condition 7.

    d. Annual fuel consumption for each natural gas pipeline heater (Ref. No. EU 6-7), calculated monthly as the sum of each consecutive twelve-month period, as required by Condition 8.

    e. The hourly fuel consumption (in scf/hour and gallons/hour) of each CT (Ref. No. EU 1-5), when in operation, as required in Condition 29.

    f. Data and calculations necessary to demonstrate compliance with the emission limits contained in Conditions 20 and 21.

    g. Scheduled and unscheduled maintenance, and operator training, as required in Condition 39.

    h. Compliance for the consecutive twelve month period (as applicable for the items above) 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.

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

33. **Reports for Continuous Monitoring Systems (Data Acquisition Report)** – The permittee shall furnish on a quarterly basis written reports of excess emissions from any process monitored by a CEMS. The reports shall be sent to the Regional Air Compliance Manager of the DEQ's NRO, postmarked no later than the 30th day following the end of the calendar quarter. These reports shall include, but are not limited to the following information:

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

    b. For each month in the quarter, report each hour in which a NOx permit limit is exceeded. The report shall include the following for each excess emission of NOx: start time, duration, equipment involved, actual NOx emissions in ppmdv@ 15% O_2, fuel type and consumption rate, nitrogen content of fuel oil (if oil fired and as required by Condition 31), actual weather conditions (temperature, barometric pressure and humidity) and CT load.

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

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

34. **Notification for Control Equipment Maintenance** – The permittee shall furnish notification to the Regional Air Compliance Manager of the DEQ's NRO of 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 shut-down. 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 shut-down period;

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

(9 VAC 5-20-180 B, 9 VAC 5-20-180 J and 9 VAC 5-80-1180 D)

35. **Notification for Facility or Control Equipment Malfunction** – The permittee shall furnish notification to the Regional Air Compliance Manager, DEQ's NRO of malfunctions of the affected facility or related air pollution control equipment that may cause excess emissions for more than one hour, by electronic 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 fourteen days of the occurrence. A permittee subject to the requirements of 9 VAC 5-40-50 C and/or 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/or 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, DEQ's NRO.
(9 VAC 5-20-180 C)

36. **Excess Emissions: Re-tuning** – Excess emissions resulting from the re-tuning of the CTs (Ref. No. EU 1-5) shall be permitted provided that:

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

b. During each CT's re-tuning event, NOx emission concentrations, based on an hourly average, shall not exceed the NOx standards of the New Source Performance Standards (NSPS) 40 CFR 60 Subpart GG – Standards of Performance for Stationary Gas Turbines (40 CFR §60.330 *et seq.*).

c. The permittee shall notify the Regional Air Compliance Manager of the DEQ's NRO 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; and

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

d. 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:

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

   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.

e. NOx 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 20 and 21.

f. The re-tuning event for each CT shall be identified on the Data Acquisition Report required by Condition 33.

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

37. **Excess Emissions: Malfunctions** – Excess emissions resulting from the malfunction shall be permitted provided that:

a. Best operational practices are adhered to and the duration of excess emissions shall be minimized.

b. During each malfunction, NOx emission concentrations, based on an hourly average, shall not exceed the NOx standards of the New Source Performance Standards (NSPS) 40 CFR 60 Subpart GG – Standards of Performance for Stationary Gas Turbines (40 CFR §60.330 *et seq.*).

c. The permittee shall notify 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.

d. As per Conditions 33 and 35, the permittee shall furnish a written report to the Regional Air Compliance Manager of the DEQ's NRO of all pertinent facts concerning the malfunction event. The notification shall include, but is not limited to, the following information:

i. Identification of the CT that experienced the malfunction; and

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.

e. NOx emissions during each malfunction shall be recorded and included in the total annual emissions as listed in Conditions 20 and 21.

f. The malfunction for each CT shall be identified on the Data Acquisition Report required by Condition 33.

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

GENERAL CONDITIONS

38. 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 so 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:

  1. 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.

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

  3. 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 a principal geographic unit of the agency.

b. Any person signing a document under subsection 'a' of this section 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 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."

c. Subsection 'b' of this condition 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 data and preparing 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.

d. Any person who fails to submit any relevant facts or who has submitted incorrect information in a document shall, upon becoming aware of such failure or incorrect submittal, promptly submit such supplementary facts or corrected information.

(9 VAC 5-20-230)

39. **Maintenance/Operating Procedures** – 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, 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)

40. **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 emissions unit;

    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 emissions limitations, in the State Implementation Plan in effect at the time an application for this permit is submitted.

    (9 VAC 5-80-1210 G & H)

41. **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)

42. **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)

43. **Change of Ownership** - In the case of a transfer of ownership of a stationary source, the new owner shall abide by any current minor NSR permit issued to the previous owner. The new owner shall notify the Regional Air Compliance Manager of DEQ's NRO of the change of ownership within 30 days of the transfer.
(9 VAC 5-80-1240)

44. **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)

ATTACHMENT C

Title IV Acid Rain Permit Application

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.

Facility (Source) Name	State	Plant Code
Louisa Generation Facility	VA	7837

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)
EU1	Yes
EU2	Yes
EU3	Yes
EU4	Yes
EU5	Yes

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;

STEP 3, Cont'd.

Recordkeeping and Reporting Requirements, 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

STEP 3, Cont'd.

Effect on Other Authorities, 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.

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

Certification

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 David N. Smith, Designated Representative	
Signature David N. Smith	Date 6/25/14