

**NORTH CAROLINA
DIVISION OF AIR QUALITY
Air Permit Review**

Region: Raleigh Regional Office
County: Wake
NC Facility ID: 9200290
Inspector's Name: Brian Bland
Date of Last Inspection: 09/17/2008
Compliance Code: 3 / In Compliance - Inspection

Permit Issue Date: xx

Facility Data			Permit Applicability (this application only)
Applicant (Facility's Name): NCSU Central Heat Plant Facility Address: NCSU Central Heat Plant 2815 Cates Avenue Raleigh, NC 27695 SIC: 8221 / Colleges And Universities, Nec NAICS: 61131 / Colleges, Universities, and Professional Schools Facility Classification: Before: Title V After: Title V Fee Classification: Before: Title V After: Title V			SIP: 2D.0503, .0516, .0521 NSPS: Subparts Db, IIII and KKKK NESHAP: Subpart ZZZZ PSD: Yes (Exempt from §51.166(j) through (r)) PSD Avoidance: NC Toxics: No 112(r): Other:
Contact Data			Application Data
Facility Contact	Authorized Contact	Technical Contact	Application Number: 9200290.09A Date Received: 01/22/2009 Application Type: Modification Application Schedule: PSD Existing Permit Data Existing Permit Number: 02977/T19 Existing Permit Issue Date: 06/15/2009 Existing Permit Expiration Date: 05/31/2014
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Review Engineer: Rahul Thaker Review Engineer's Signature: _____ Date: July 30, 2009		Comments / Recommendations:	
		Issue 02977/T20 Permit Issue Date: Permit Expiration Date:	

1. Purpose of Application

North Carolina State University (NCSU) has submitted a permit application to revise its existing permit for the following reasons:

- To remove the existing boilers (ID Nos. ES-02, ES-03, and ES-04) and replace them with new boilers (ID Nos. ES-2A, ES-3A, and ES-4A).
- To remove existing boiler (ID No. ES-01) and replace it with new combustion turbines (ID Nos. ES-1A and ES-1B).
- To install a new emergency generator (ID No. ES-63).
- To move the existing generator (ID No. ES-17) to a different location of the facility.

2. Facility Description

The university campus is located in the southwest Raleigh. The campus hosts a major state university with undergraduate enrollment in excess of 30,000 students. Permitted sources are primarily boilers, emergency power generators, chillers, heaters, and dryers. They are located at different portions of the university: Main Campus, Centennial campus, Veterinary Medicine College, and Carter Finley Stadium complex.

NCSU is an existing major source for several criteria pollutants for Title V of the Clean Air Act (CAA). But it is an existing minor source for hazardous air pollutants for the Title V program.

3. Application Chronology

Refer to “Comprehensive Application Report” for complete details.

4. Statement of Compliance

The applicant has certified through submittal of E5 Form that the facility is in compliance with all applicable requirements.

The Region (Brian Bland of RRO) had inspected the facility on 9/17/08 and concluded, “At the time of inspection, the facility appeared to be in compliance with all permitting requirements.”

5. Permit History

Current air permit 02977T19 was issued on June 15, 2009, as per the procedures in 2Q .0513 “Permit Renewal and Expiration”.

6. Permit Modification/Changes

6.1 To remove existing boilers (ID Nos. ES-02, ES-03 and ES-04) and replace them with new boilers (ID Nos. ES-2A, ES-3A and ES-4A).

The Permittee wishes to replace three existing natural gas/No. 6 fuel oil fired boilers (ID Nos. ES-02, ES-03, and ES-04) located at the Yarbrough Steam Plant. The heat input capacities are 141 million Btu/hr (ES-02, installed in 1949), 73.2 million Btu/hr (ES-03, installed in 1951), and 73.2 million Btu/hr (ES-03, installed in 1951).

The Permittee stated that its steam plant study had revealed that it would gain the most benefit by removing and replacing the above boilers with three, new, natural gas/No. 2 fuel oil fired boilers (121.4 million Btu/hr each, ES-2A, ES-3A and ES-4A).

The following is an emission summary for each of these new boilers: The estimate is based upon 8,760 hrs of operation, emission factors in AP-42 (Section 1.3 Fuel Oil Combustion, 9/98, and Section 1.4 Natural Gas Combustion, 7/98), equipment designer emissions data, and emission limitations in NSPS Subpart IIII.

Pollutant	Potential Emissions TONS/YR	Potential Emissions TONS/YR
	Each Boiler No. 2 Fuel Oil	Each Boiler Natural Gas
PM	26.6	3.72
PM-10	26.6	3.72
PM-2.5	26.6	3.72
NOx	106.3	106.3
VOC	26.6	2.1
CO	40.9	19.7
SO ₂	170.1	0.3
Single HAP	0.008 (Selenium)	0.94 (Hexane)
Total HAP	> 0.008	0.98

Each of the boilers is subject to the requirements of 2D .0503, .0521, .0524, and .0530.

15A NCAC 2D .0503 "Particulates From Fuel Burning Indirect Heat Exchangers"

This regulation applies to particulate matter (PM) emissions from indirect heat exchangers, except the PM emissions from electric steam generating units are subject to 2D .0536.

Emissions of PM from combustion of natural gas or No. 2 fuel oil that are discharged from each boiler into the atmosphere shall not exceed PM emission rate as derived using 2D .0503(c).

Accordingly, allowable emissions of particulate matter (PM) from burning of natural gas or No. 2 fuel oil in each boiler shall be calculated as follows.

$$E = 1.090 \times Q^{-0.2594} \quad \text{Where: } E = \text{allowable PM emission rate in lbs/million Btu heat input}$$
$$Q = \text{maximum heat input rate in million Btu per hour at the plant site}$$

The maximum heat input rates of all permitted boilers, new boilers requested to be permitted and existing boilers requested to be removed from the permit, and new turbines (HRSG portion only) requested to be permitted, have been considered for estimating the PM emission rate of each of these new sources, as per 2D .0503(e).

$$Q = \begin{aligned} & [726.26 \text{ million Btu/hr}] \text{ (heat input rate of all permitted boilers as per permit review for 02977T18)} \\ & + [3 * 121.4 \text{ million Btu/hr}] \text{ (heat input rate of each of the new boilers to be permitted)} \\ & + [2 * 27 \text{ million Btu/hr}] \text{ (heat input rate of HRSG of each new turbine to be permitted)} \\ & - [127.9 \text{ million Btu/hr}] \text{ (boiler ES-01 to be removed from the permit)} \\ & - [141 \text{ million Btu/hr}] \text{ (boiler ES-02 to be removed from the permit)} \\ & - [2 * 73.2 \text{ million Btu/hr}] \text{ (boilers ES-03 and ES-04 to be removed from the permit)} \end{aligned}$$
$$= 729.2 \text{ million Btu/hr}$$

$$\text{Therefore, } E = 1.090 \times 729.2^{-0.2594}$$
$$= 0.20 \text{ million Btu/hr (Appx.)}$$

The above allowable emission rate of 0.20 lb/million Btu for PM is **24.3 lbs/hr** at each boiler's maximum heat input rate (0.20 lb PM/million Btu x 121.4 million Btu/hr each).

Using the AP-42 emission factor for worse case fuel (No.2 fuel oil), the PM emission rate for the boiler can be estimated as

$$(2 \text{ lb PM}/1000 \text{ gal No. 2 fuel oil}) \times (\text{gal No. 2 fuel oil}/140000 \text{ Btu}) \times (121.4 \text{ million Btu/hr}) = \mathbf{1.73 \text{ lb/hr}}$$
 each

Moreover, the company has estimated PM emission rate of **6.07 lb/hr** (or 26.59 tons/yr) for each boiler burning No. 2 fuel oil, based upon vendor emission factor of 0.05 lb/million Btu.

Compliance with the PM emission standard of 2D .0503 is expected, as the worst-case potential emission rate (6.07 lb/hr) for PM is less than the allowable emission rate (24.3 lb/hr). Because the worse-case potential emission rate is significantly lower than the allowable emission rate, no monitoring / record keeping / reporting will be required for particulate emissions from these boilers due to firing of No. 2 fuel oil or natural gas.

15A NCAC 2D .0516 "Sulfur Dioxide Emissions from Combustion Sources"

Emission of sulfur dioxide from any source of combustion that is discharged from any vent, stack, or chimney shall not exceed 2.3 pounds of sulfur dioxide per million BTU input. Sulfur dioxide formed by the combustion of sulfur in fuels, wastes, ores, and other substances shall be included when determining compliance with this standard.

Sulfur dioxide formed or reduced as a result of treating flue gases with sulfur trioxide or other materials shall also be accounted for when determining compliance with this standard.

A source subject to an emission standard for sulfur dioxide in Rules .0524, .0527, .1110, .1111, .1205, .1206, .1210, or .1211 of 15A NCAC shall meet the standard in that particular rule instead of the 2.3 lb/million Btu emission standard under 2D .0516.

As discussed below, the proposed boilers are subject to the requirements in NSPS Subpart Db for SO₂ emission standard. Hence, these boilers are NOT subject to 2D .0516 requirements.

15A NCAC 2D .0524 "New Source Performance Standards"

US EPA has promulgated "Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units" in 40 CFR 60 Subpart Db (Revised lastly at 74 FR 5084, January 28, 2009). This NSPS applies to each steam-generating unit that commences construction, modification, or reconstruction after June 19, 1984 and that has a heat input capacity from the fuels combusted in the steam-generating unit of greater than 100 million Btu/hr.

Each of the proposed boilers (ES-1A, ES-1B and ES-1C) has a heat input capacity greater than 100 million Btu/hr and will be constructed after June 19, 1984. Thus, these boilers are deemed to be subject to the NSPS requirements in this Subpart.

§ 60.42b Standard for Sulfur Dioxide (SO₂)

Paragraph (k)(1) of this Section states that no owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, natural gas, a mixture of these fuels, or a mixture of these fuels with any other fuels shall cause to be discharged into the atmosphere any gases that contain SO₂ in excess of 0.20 lb/MMBtu heat input or 8 percent (0.08) of the potential SO₂ emission rate (92 percent reduction) and 1.2 lb/MMBtu heat input.

Subparagraph (k)(2) states that the steam-generating units firing only very low sulfur oil, gaseous fuel, a mixture of these fuels, or a mixture of these fuels with any other fuels with a potential SO₂ emission rate of 0.32 lb/MMBtu heat input or less are exempt from the SO₂ emissions limit in paragraph (k)(1) of this Section.

The definition of "very low sulfur oil" in §60.41b is as follows:

"...For units constructed, reconstructed, or modified after February 28, 2005 and not located in a noncontinental area, *very low sulfur oil* means oil that contains no more than 0.30 weight percent sulfur or that, when combusted without SO₂ emission control, has a SO₂ emission rate equal to or less than 140 ng/J (0.32 lb/MMBtu) heat input..."

The Permittee has elected to use "very low sulfur oil" with a maximum sulfur content of 0.3 weight percent and gaseous fuel so that the proposed boilers would be subject to 0.32 lb/million Btu emission limit (Paragraph (k)(2)) instead of 0.2 lb/million Btu emission limit (Paragraph (k)(1)).

Finally, in accordance with Paragraph (e) of this Section, compliance with the SO₂ standard or fuel oil sulfur limit shall be based upon a 30-day rolling average basis.

In addition, in accordance with Paragraph (g) of this Section, the SO₂ emission standard shall apply at all times, including periods of startup, shutdown, and malfunction.

§ 60.43b Standard for Particulate Matter (PM)

Paragraph (f)

On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that can combust coal, oil, wood, or mixtures of these fuels with any other fuels shall cause to be discharged into the atmosphere any gases that exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity. Owners and operators of an affected facility that elect to install, calibrate, maintain, and operate a

continuous emissions monitoring system (CEMS) for measuring PM emissions according to the requirements of this subpart and are subject to a federally enforceable PM limit of 0.030 lb/MMBtu or less are exempt from the opacity standard specified in this paragraph.

Thus, the proposed boilers are subject to 20 percent opacity standard when burning fuel oil or fuel oil in combination with natural gas. These boilers are not subject to any federally enforceable PM emission standard of 0.03 lb/million Btu. Hence, the boilers are NOT exempt from the 20 percent opacity standard.

It should be noted here that these boilers are subject to 20 percent opacity limit in 2D .0521 when burning natural gas.

Paragraph (g)

The PM and opacity standards apply at all times, except during periods of startup, shutdown or malfunction.

Paragraphs (h)(1) and (h)(5)

Except as provided in paragraphs (h)(2), (h)(3), (h)(4), (h)(5), and (h)(6) of this Section, on and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 13 ng/J (0.030 lb/MMBtu) heat input.

On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, an owner or operator of an affected facility not located in a noncontinental area that commences construction, reconstruction, or modification after February 28, 2005, and that combusts only oil that contains no more than 0.30 weight percent sulfur, coke oven gas, a mixture of these fuels, or either fuel (or a mixture of these fuels) in combination with other fuels not subject to a PM standard in §60.43b and not using a post-combustion technology (except a wet scrubber) to reduce SO₂ or PM emissions is not subject to the PM limits in (h)(1) of this section.

As indicated above for the SO₂ emission standard, the Permittee has chosen to use “very low sulfur oil”, thus limiting the sulfur content to 0.3 weight percent. In addition, the burning of oil with any other fuel (such as natural gas) is not subject to any PM standard and the Permittee is not proposing any post-combustion technology to reduce either SO₂ or PM emissions. Therefore, the proposed boilers are NOT subject to any PM standard under this NSPS, except the opacity standard as discussed above. Thus, these boilers will be subject to the PM SIP standard in 2D .0503.

§60.44b Standard for Nitrogen Oxides (NO_x)

Paragraph (a)

The NSPS includes the following emission limits when burning only natural gas or No. 2 fuel oil in boilers:

Fuel/steam generating unit type	Nitrogen oxide emission limits (expressed as NO ₂) heat input	
	ng/J	lb/MMBTU
(1) Natural gas and distillate oil		
(i) Low heat release rate	43	0.10
(ii) High heat release rate	86	0.20

§60.41b defines “high heat release rate” as heat release rate greater than 730,000 J/sec-m³ (70,000 Btu/hr-ft³). As per the Permittee, the proposed boilers have heat release rate of 100,885 Btu/hr-ft³. Thus, the boilers are subject to NOx emission standard of 0.2 lb/million Btu when firing natural gas or No. 2 fuel oil.

Paragraph (b)

The Permittee shall meet the following emission limits when simultaneously burning mixtures of oil and natural gas:

$$E_n = \frac{EL_{go} \cdot H_{go}}{H_{go}}$$

Where:

E_n = NO_x emission limit (expressed as NO₂), ng/J (lb/MMBtu)

EL_{go} = Appropriate emission limit from paragraph (a)(1) of §60.44b for combustion of natural gas or distillate oil, ng/J (lb/MMBtu)

H_{go} = Heat input from combustion of natural gas or distillate oil, J (MMBtu)

Paragraph (c)

If the Permittee is burning simultaneously oil or a mixture of this fuel with natural gas, then it shall meet the emission limit for the oil or mixture of this fuel with natural gas combusted in the affected facility, as determined pursuant to paragraph (a) or (b) of §60.44b, unless the affected facility has an annual capacity factor for oil or mixture of this fuel with natural gas of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less for oil or a mixture of this fuel with natural gas.

Paragraph (h)

NOx standards under this Section shall apply at all times including periods of startup, shutdown, or malfunction.

Paragraph (i)

Compliance with the NOx standards shall be based upon a 30-day rolling average basis.

§ 60.45b Compliance and Performance Test Methods and Procedures for Sulfur Dioxide

Paragraph (k)

As stated above, the Permittee has elected to comply with § 60.42b(k)(2) for SO₂; therefore, it shall follow the applicable procedures in § 60.49b(r).

§ 60.46b Compliance and Performance Test Methods and Procedures for Particulate Matter and Nitrogen Oxides

Paragraph (a)

The PM and opacity limits shall apply at all times except during periods of startup, shutdown, or malfunction. The NOx emission standards shall apply at all times.

Paragraph (c)

Compliance with the NO_x emission standards under §60.44b shall be determined through performance testing under Paragraph (e) or (f), or under Paragraphs (g) and (h) of this Section, as applicable.

Paragraph (d)

The Permittee shall conduct an initial performance test to demonstrate compliance with opacity limit as required in Section 60.8.

Paragraph (e)

To determine compliance with the emission limits for NO_x required under §60.44b, the owner or operator of an affected facility shall conduct the performance test as required under §60.8 using the continuous system for monitoring NO_x under §60.48(b).

For the initial compliance test, NO_x from the steam-generating units are monitored for 30 successive steam generating unit operating days and the 30-day average emission rate is used to determine compliance with the NO_x emission standards under §60.44b. The 30-day average emission rate is calculated as the average of all hourly emissions data recorded by the monitoring system during the 30-day test period.

Following the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, the owner or operator of an affected facility that has a heat input capacity of 73 MW (250 MMBtu/hr) or less and that combusts natural gas or distillate oil shall upon request determine compliance with the NO_x standards in §60.44b through the use of a 30-day performance test. During periods when performance tests are not requested, NO_x emissions data collected pursuant to §60.48b(g)(1) or §60.48b(g)(2) are used to calculate a 30-day rolling average emission rate on a daily basis and used to prepare excess emission reports, but will not be used to determine compliance with the NO_x emission standards. A new 30-day rolling average emission rate is calculated for each steam generating unit operating day as the average of all of the hourly NO_x emission data for the preceding 30 steam generating unit operating days.

Paragraph (i)

For PM, the Permittee shall follow the applicable procedures in §60.49b(r) to demonstrate compliance with the PM limit in § 60.43b(h)(5).

§ 60.47b Emission Monitoring for Sulfur Dioxide

Paragraph (f)

The owner or operator of an affected facility that combusts very low sulfur oil or is demonstrating compliance under §60.45b(k) is not subject to the emission monitoring requirements under Paragraph (a) of this Section if the owner or operator maintains fuel records as described in §60.49b(r).

As stated above, the proposed boilers will combust very low sulfur fuel oil and will demonstrate compliance in accordance with § 60.45b(k). Thus, the Permittee must maintain records in §60.49b(r).

§ 60.48b Emission Monitoring for Particulate Matter and Nitrogen Oxides

Paragraph (a)

The Permittee shall install, calibrate, maintain, and operate a continuous opacity monitoring systems (COMS) on boilers (ID Nos. ES-2A, ES-3A and ES-4A) for measuring the opacity of emissions discharged to the atmosphere and record the output of the system.

The owner or operator of an affected facility subject to an opacity standard under §60.43b and meeting the conditions under Paragraphs (j)(1), (2), (3), (4), or (5) of this Section who elects not to install a COMS shall conduct a performance test using Method 9 of Appendix A-4 of this Part and the procedures in §60.11 to demonstrate compliance with the applicable limit in §60.43b and shall comply with either paragraphs (a)(1), (a)(2), or (a)(3) of this Section.

Paragraph (b)

The owner or operator of an affected facility subject to a NO_x standard under §60.44b shall comply with either Paragraphs (b)(1) or (b)(2) of this Section.

(1) Install, calibrate, maintain, and operate CEMS for measuring NO_x and O₂ (or CO₂) emissions discharged to the atmosphere, and shall record the output of the system; or

(2) If the owner or operator has installed a NO_x emission rate CEMS to meet the requirements of Part 75 of this Chapter and is continuing to meet the ongoing requirements of Part 75 of this Chapter, that CEMS may be used to meet the requirements of this Section, except that the owner or operator shall also meet the requirements of §60.49b. Data reported to meet the requirements of §60.49b shall not include data substituted using the missing data procedures in subpart D of part 75 of this Chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this Chapter.

Paragraph (c)

The CEMS required under paragraph (b) of this section shall be operated and data recorded during all periods of operation of the affected facility except for CEMS breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments.

Paragraph (d)

The 1-hour average NO_x emission rates measured by the continuous NO_x monitor required by Paragraph (b) of this Section and required under §60.13(h) shall be expressed in lb/MMBtu heat input and shall be used to calculate the average emission rates under §60.44b. The 1-hour averages shall be calculated using the data points required under §60.13(h)(2).

Paragraph (e)

The procedures under §60.13 shall be followed for installation, evaluation, and operation of the continuous monitoring systems.

Paragraph (f)

When NO_x emission data are not obtained because of CEMS breakdowns, repairs, calibration checks and zero and span adjustments, emission data will be obtained by using standby monitoring systems, Method 7 of Appendix A of this part, Method 7A of Appendix A of this Part, or other approved reference methods to provide emission data for a minimum of 75 percent of the operating hours in each steam generating unit operating day, in at least 22 out of 30 successive steam generating unit operating days.

Paragraph (j)(2) and (6)

The owner or operator of an affected facility that meets the conditions in either paragraph (j)(1), (2), (3), (4), (5), or (6) of this Section is not required to install or operate a COMS.

The Permittee has indicated that it will not be able to meet any of the exemptions given in §60.48b(j). Hence, it must monitor opacity emissions using COMs.

§ 60.49b Reporting and Recordkeeping Requirements

Paragraph (a)

The Permittee shall submit notification of the date of initial startup, as provided by §60.8. This notification shall include the following:

The design heat input capacity of the affected facility and identification of the fuels to be combusted in the affected facility:

If applicable, a copy of any federally enforceable requirement that limits the annual capacity factor for any fuel or mixture of fuels under §§60.42b(d)(1), 60.43b(a)(2), (a)(3)(iii), (c)(2)(ii), (d)(2)(iii), 60.44b(c), (d), (e), (i), (j), (k), 60.45b(d), (g), 60.46b(h), or 60.48b(i);

The annual capacity factor at which the owner or operator anticipates operating the facility based on all fuels fired and based on each individual fuel fired; and

Notification that an emerging technology will be used for controlling emissions of SO₂. The Administrator will examine the description of the emerging technology and will determine whether the technology qualifies as an emerging technology. In making this determination, the Administrator may require the owner or operator of the affected facility to submit additional information concerning the control device. The affected facility is subject to the provisions of §60.42b(a) unless and until this determination is made by the Administrator.

Paragraph (b)

The owner or operator of each affected facility subject to the SO₂, PM, and/or NO_x emission limits under §§60.42b, 60.43b, and 60.44b shall submit to the Administrator the performance test data from the initial performance test and the performance evaluation of the CEMS using the applicable performance specifications in appendix B of this part. The owner or operator of each affected facility described in §60.44b(j) or §60.44b(k) shall submit to the Administrator the maximum heat input capacity data from the demonstration of the maximum heat input capacity of the affected facility.

Paragraph (d)

The owner or operator of an affected facility shall record and maintain records of the amounts of each fuel combusted during each day and calculate the annual capacity factor individually for coal, distillate oil, residual oil, natural gas, wood, and municipal-type solid waste for the reporting period. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of each calendar month.

Paragraph (f)

For an affected facility subject to the opacity standard in §60.43b, the owner or operator shall maintain records of opacity. In addition, an owner or operator that elects to monitor emissions according to the requirements in §60.48b(a) shall maintain records according to the requirements specified in paragraphs (f)(1) through (3) of this Section, as applicable to the visible emissions monitoring method used.

Paragraph (g)

The owner or operator of an affected facility subject to the NO_x standards under §60.44b shall maintain records of information as specified in paragraph (g)(1) through (g)(10).

Paragraph (i)

The owner or operator of any affected facility subject to the continuous monitoring requirements for NO_x under §60.48(b) shall submit reports containing the information recorded under paragraph (g) of this Section.

Paragraph (o)

All records required under this Section shall be maintained by the owner or operator of the affected facility for a period of 2 years following the date of such record.

Paragraph (r)

The owner or operator of an affected facility who elects to use the fuel based compliance alternatives in §60.42b or §60.43b shall either:

(1) The owner or operator of an affected facility who elects to demonstrate that the affected facility combusts only very low sulfur oil, natural gas, wood, a mixture of these fuels, or any of these fuels (or a mixture of these fuels) in combination with other fuels that are known to contain an insignificant amount of sulfur in §60.42b(j) or §60.42b(k) shall obtain and maintain at the affected facility fuel receipts from the fuel supplier that certify that the oil meets the definition of distillate oil and gaseous fuel meets the definition of natural gas as defined in §60.41b and the applicable sulfur limit. For the purposes of this section, the distillate oil need not meet the fuel nitrogen content specification in the definition of distillate oil. Reports shall be submitted to the Administrator certifying that only very low sulfur oil meeting this definition, natural gas, wood, and/or other fuels that are known to contain insignificant amounts of sulfur were combusted in the affected facility during the reporting period; or

(2) The owner or operator of an affected facility who elects to demonstrate compliance based on fuel analysis in §60.42b or §60.43b shall develop and submit a site-specific fuel analysis plan to the Administrator for review and approval no later than 60 days before the date you intend to demonstrate compliance. Each fuel analysis plan shall include a minimum initial requirement of weekly testing and each analysis report shall contain, at a minimum, the following information:

- (i) The potential sulfur emissions rate of the representative fuel mixture in ng/J heat input;
- (ii) The method used to determine the potential sulfur emissions rate of each constituent of the mixture. For distillate oil and natural gas a fuel receipt or tariff sheet is acceptable;
- (iii) The ratio of different fuels in the mixture; and
- (iv) The owner or operator can petition the Administrator to approve monthly or quarterly sampling in place of weekly sampling.

6.2 To remove existing boiler (ID No. ES-01) and replace it with new combustion turbines (ID Nos. ES-1A and ES-1B).

The Permittee requests to remove natural gas/No. 6 fuel oil-fired boiler (127.9 million Btu/hr, ID No. ES-01) located on Cates Avenue. The company proposes to replace this boiler with two combustion turbines, which are to be used as cogeneration units.

Specifically, the simple cycle portion (gas turbine) will be operated either with natural gas (66.3 million Btu/hr heat input rate) or No. 2 fuel oil (heat input rate 63.3 million Btu/hr) with a power output of 5.5 MW for each. The exhaust of the power turbine will be sent to heat recovery steam generator (HRSG) to recover heat from the exhaust gases. The steam production in HRSG will be augmented using natural gas fired duct burners (heat input rate 27 million Btu/hr each). The steam produced in HRSG will be used to satisfy the steam needs of various campus locations.

As per the Permittee, the proposed cogeneration units can operate in any of the following operating scenarios: (i) gas turbine and HRSG concurrently, (ii) gas turbine only, and (iii) HRSG only.

The following is an emission summary for each of these combustion turbines: The estimate is based upon 8,760 hrs of operation, emission factors in AP-42 (Section 3.1 Stationary Gas Turbines, 4/00), equipment designer emissions data, and emission limitations in NSPS Subpart KKKK.

Pollutant	Potential Emissions TONS/YR	Potential Emissions TONS/YR
	Each Turbine including HRSG (No. 2 Fuel Oil in Turbine and NG in HRSG)	Each Turbine including HRSG (NG in Turbine and NG in HRSG)

PM	17.8	9.9
PM-10	17.8	9.9
PM-2.5	17.8	9.9
NOx	93.2	35.5
VOC	10.3	2.2
CO	43.6	40.7
SO ₂	23.7	24.5
Single HAP	0.22 (manganese)	0.29 (formaldehyde)
Total HAP	< 25 tons	< 25 tons

Each of these turbines is subject to the requirements of 2D .0503, .0521, and .0524.

15A NCAC 2D .0503 "Particulates From Fuel Burning Indirect Heat Exchangers"

This regulation applies to particulate matter (PM) emissions from indirect heat exchangers, except the PM emissions from electric steam generating units are subject to 2D .0536.

Emissions of PM from combustion of natural gas or No. 2 fuel oil that are discharged from each boiler into the atmosphere shall not exceed PM emission rate as derived using 2D .0503(c).

Accordingly, allowable emissions of particulate matter (PM) from burning of natural gas or No. 2 fuel oil in each turbine (HRSG only) shall be calculated as follows.

$$E = 1.090 \times Q^{-0.2594} \quad \text{Where: } E = \text{allowable PM emission rate in lbs/million Btu heat input}$$

$$Q = \text{maximum heat input rate in million Btu per hour at the plant site}$$

The maximum heat input rates of all permitted boilers, new boilers requested to be permitted and existing boilers requested to be removed from the permit, and new turbines (HRSG portion only) requested to be permitted, have been considered for estimating the PM emission rate of each of these new sources, as per 2D .0503(e).

As shown in Section 6.1 above,

$$Q = 729.2 \text{ million Btu/hr and}$$

$$E = 0.20 \text{ lb/million Btu.}$$

The above allowable emission rate of 0.20 lb/million Btu for PM is **5.4 lbs/hr** at each boiler's maximum heat input rate (0.20 lb PM/million Btu x 27 million Btu/hr each).

The potential PM emission rate of each turbine (HRSG only) is 0.27 lb/hr. Hence, compliance is expected.

15A NCAC 2D .0521 "Control of Visible Emissions"

The intent of this Rule is to prevent, abate and control emissions generated from fuel burning operations and industrial processes where visible emissions can be reasonably expected to occur, except during startup, shutdowns, and malfunctions approved as such according to procedures approved under 15A NCAC 2D .0535.

For sources manufactured after July 1, 1971, visible emissions shall not be more than 20 percent opacity when averaged over a six-minute period. However, except for sources required to install, operate, and maintain continuous opacity monitoring systems (COMS), compliance with the 20 percent opacity limit shall be determined as follows:

- i. No six-minute period exceeds 87 percent opacity;
- ii. No more than one six-minute period exceeds 20 percent opacity in any hour; and
- iii. No more than four six-minute periods exceed 20 percent opacity in any 24-hour period.

Excess emissions during startup and shutdown shall be excluded from the determinations in paragraphs i. and ii. above, if the excess emissions are exempted according to the procedures set out in 2D .0535(g). Excess emissions during malfunctions shall be excluded from the determinations in paragraphs i. and ii. above, if the excess emissions are exempted according to the procedures set out in 2D .0535(c).

All periods of excess emissions shall be included in the determinations in paragraphs i. and ii. above, until such time that the excess emissions are exempted according to the procedures in 2D .0535.

Two combustion turbines (ID Nos. ES-1A and ES-1B) are subject to this standard. Visible emissions due to burning of natural gas and low sulfur No. 2 fuel oil in these sources are expected to be low due to inherently clean fuels. Compliance is expected.

15A NCAC 2D .0524 "New Source Performance Standards"

The EPA Administrator has promulgated a final rule under 40 CFR 60 Subpart KKKK, "Standards of Performance for Stationary Combustion Turbines". See 71 FR 38482, July 6, 2006.

Applicability

The regulation applies to each stationary combustion turbine with a heat input at peak load equal to or greater than 10 million Btu per hour based on higher heating value, which commenced construction, modification, or reconstruction after February 18, 2005.

Only heat input rate to the combustion turbine should be included when determining whether or not this NSPS is applicable to the proposed turbines. Any additional heat input to associated heat recovery steam generators (HRSG) or duct burners should not be included when determining your peak heat input. However, the NSPS does apply to emissions from any associated HRSG and duct burners.

The construction of each of the new combustion turbines at the NCSU is expected to commence in 2009. The peak load heat input rate of each of the turbines (without the heat input of HRSG) is 66.3 million Btu/hr firing natural gas and 63.3 million Btu/hr firing fuel oil. Hence, the proposed combustion turbines are subject to this regulation.

Emission Limits for NO_x

The proposed turbines (when operating gas turbine only or gas turbine and HRSG concurrently) are subject to an emission standard of 25 ppm at 15 percent O₂ or 1.2 lb/MWh, when fired with natural gas.

These turbines (when operating gas turbine only or gas turbine and HRSG concurrently) are subject to an emission standard of 74 ppm at 15 percent O₂ or 3.6 lb/MWh, when fired with fuels other than natural gas.

If the turbines (when operating gas turbine only or gas turbine and HRSG concurrently) operate at partial load (less than 75 percent of peak load) or if the turbines operate at temperatures less than 0°F, the NO_x limit of 96 ppm at 15 percent O₂ or 4.7 lb/MWh would apply.

Finally, the HRSGs, if operating independently of the combustion turbines, will be subject to an emission standard of 54 ppm at 15 percent O₂ or 0.86 lb/MWh, when fired with natural gas or any other fuels.

The proposed turbines are equipped with dry low-NO_x combustion system (gas turbine) and low NO_x burners (HRSG). The equipment vendor data indicates predicted NO_x emission rate of 24 ppm at 15% O₂. Hence, compliance is expected. The actual compliance with these emission standards will be verified during the initial performance test.

Emission Limits for SO₂

These turbines will be subject to an emission limit of 0.9 lb/MWh gross output or the turbines must not burn any fuel, which contains the total potential sulfur emissions in excess of 0.06 lb SO₂/million Btu heat input.

The Permittee has chosen to comply with input-based emission standard for SO₂.

The proposed turbines will burn pipeline quality natural gas or low sulfur No. 2 fuel oil. Using 0.2 grains sulfur/100 ft³ sulfur content and 1,020 Btu/sft³ (HHV) heat content for natural gas, the potential SO₂ emission rate for each turbine can be estimated as 0.00056 lb/million Btu. Similarly, using sulfur content of 0.05 percent weight in No. 2 fuel oil and heat content of 19,580 Btu/lb (HHV), the potential SO₂ emission rate for each turbine can be estimated as 0.051 lb/million Btu. Hence, compliance is expected while firing natural gas and fuel oil.

General Compliance Requirements

The Permittee must operate and maintain the proposed combustion turbines, air pollution control equipment (if any), and monitoring equipment (if any) in a manner consistent with good air pollution control practices for minimizing emissions at all times during start-up, shutdown, and malfunction.

When an affected combustion turbine with heat recovery utilizes a common steam header with one or more combustion turbines, the Permittee shall either:

Determine compliance with the applicable NO_x emissions limits by measuring the emissions combined with the emissions from the other combustion turbine(s) utilizing the common heat recovery unit; or

Develop, demonstrate, and provide information satisfactory to the Administrator on methods for apportioning the combined gross energy output from the heat recovery unit for each of the affected combustion turbines. The Administrator may approve such demonstrated substitute methods for apportioning the combined gross energy output measured at the steam turbine whenever the demonstration ensures accurate estimation of emissions related under this part.

Monitoring

If the Permittee is using water injection to control NO_x emissions, the Permittee must install, calibrate, maintain and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine. In the alternate, the Permittee can install, calibrate, maintain and operate NO_x continuous emission monitoring system (CEM).

If the Permittee is not using water injection to control NO_x emissions, the Permittee must perform annual performance tests (subsequent to initial performance test) to demonstrate continuous compliance. If the NO_x emission result from the performance test is less than or equal to 75 percent of the NO_x emission limit for the turbine, the frequency of testing can be reduced to once every two years for subsequent performance tests. If the results of any subsequent performance test exceed 75 percent of the NO_x emission limit, the Permittee must resume the annual performance tests.

As an alternate to the annual performance tests, the Permittee can

- install, calibrate, maintain, and operate NO_x CEM or
- install applicable continuous parameter monitoring systems for air pollution control equipment (if any) or
- with the DAQ approval for the affected units which are also subject to Part 75, monitor the NO_x emission rate using the Part 75 Appendix E methodology or the low mass emissions methodology in §75.19.

The Permittee must monitor the total sulfur content of the fuel being fired in the turbine, except that the Permittee can elect not to monitor the total sulfur content of the fuel combusted in the turbine provided that the fuel is demonstrated not to exceed potential sulfur emissions of 0.06 lb SO₂/million Btu heat input.

To make a demonstration that the potential sulfur emissions of 0.06 lb SO₂/million Btu heat input are not exceeded, the Permittee can elect to use valid purchase contract, tariff sheets or transportation contract specifying that the total

sulfur content for natural gas is 20 grains of sulfur or less per 100 sft³ and that the maximum total sulfur content for oil use is 0.05 weight percent (500 ppmw) or less. Alternatively, the Permittee can use representative fuel sampling data to show that the sulfur content of the natural gas does not exceed 0.06 lb SO₂/million Btu heat input.

If the Permittee chooses not to demonstrate compliance with the sulfur content of the fuel as above and the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel must be determined and recorded once per unit operating day. The Permittee can also develop custom fuel schedules to determine total sulfur content of gaseous fuels. The regulation includes two, custom sulfur monitoring schedules, which are available without prior EPA approval.

Reporting

For each affected unit required to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content under this Subpart, the Permittee must submit reports of excess emissions and monitor downtime, in accordance with §60.7(c). Excess emissions must be reported for all periods of unit operation, including start-up, shutdown, and malfunction. For each affected unit that conducts annual performance tests in accordance with §60.4340(a), the Permittee must submit a written report of the results of each performance test before the close of business on the 60th day following the completion of the performance test.

Performance Tests

The Permittee is required to conduct initial and subsequent performance tests as per §60.4400 and §60.4415 for NO_x and sulfur dioxide, respectively, with such exemptions as may be allowed.

NO_x

The Permittee is required to conduct an initial performance test within 60 days after achieving the maximum production rate but not later than 180 days of initial start-up for NO_x for each combustion turbine.

It should be noted here that under 40 CFR 60 Subpart GG (Standards of Performance for Stationary Gas Turbines) EPA has waived the initial performance test requirements for the other identical turbines (with no manufacturer deviation) located at the same location and burning the same fuel, contingent upon the stack test results of the identical combustion turbine showing a high compliance margin for the NO_x emission standard. Refer to EPA ADI Control Numbers 0300035, 0100007, and 0300053.

Thus, DAQ will require initial performance testing for only one of the two combustion turbines (ID Nos. ES-1A and ES-1B) for both simple cycle and combined heat and power cycle for firing both natural gas and No. 2 fuel oil.

The Permittee is required to perform annual testing (no more than 14 calendar months following the previous performance test) for NO_x, if the Permittee is not using water injection to comply.

Each performance test for NO_x must be conducted at ± 25 percent of 100 percent peak load or at the highest achievable load point if at least 75 percent peak load cannot be achieved in practice. Three runs are required for each performance test and each run must last for a minimum 20 minutes. The ambient temperature for each test run must be above 0 °F.

If the NO_x emission result from any annual performance test is less than or equal to 75 percent of the NO_x emission limit for the proposed combustion turbine, the frequency of testing can be reduced to once every two years for subsequent performance tests. If the results of any subsequent performance test exceed 75 percent of the NO_x emission limit, the Permittee must resume the annual performance tests.

SO₂

The Permittee is required to conduct an initial performance test within 60 days after achieving the maximum production rate but not later than 180 days of initial start-up for sulfur dioxide on each turbine. Similar to the

rationale given above for NOx initial performance testing, DAQ will require stack testing for SO₂ on only one combustion turbine instead of both.

Each subsequent test for sulfur dioxide shall be conducted once every year (no more than 14 calendar months following the previous performance test). The Permittee can opt not to demonstrate compliance with SO₂ stack limit and can instead opt for fuel sulfur limit to comply with the sulfur stack-testing requirement.

If the Permittee opts to determine fuel sulfur to comply with the stack-testing requirement, then the Permittee must **monitor** total sulfur content of the fuel being fired in the turbine. The sulfur content of the fuel must be determined using total sulfur methods in §60.4415. The Permittee must monitor natural gas once per unit operating day if the fuel is supplied without intermediate bulk storage.

Alternatively, the Permittee can choose **not to monitor** the total potential sulfur emissions of the fuel combusted in the turbine, if it can be demonstrated that the fuel does not exceed 0.06 lb SO₂/million Btu in continental areas. This demonstration can be performed by using the fuel quality characteristics in a current, valid purchase contract, tariff sheet, or transportation contract for the fuel, specifying that the maximum sulfur content for natural gas used is 20 grains of sulfur or less per 100 standard cubic feet and that the maximum total sulfur content for oil use is 0.05 weight percent (500 ppmw) or less. The other option for demonstration is through representative fuel sampling data showing that the potential sulfur emissions of the fuel does not exceed 0.06 lb SO₂/million Btu in continental areas. In this case, the Permittee must provide at a minimum the amount of data in Section 2.3.1.4 or 2.3.2.4. of Appendix D of Part 75.

6.3 To install a new emergency generator (ID No. ES-63).

The Permittee is requesting to obtain approval of a new diesel-fired emergency generator, with a maximum engine power not to exceed 1,500 kW (electric) [2,011 HP (electric)].

The following is an emission summary for this generator. Potential emissions are based upon 500 hrs of operation. The emission estimate for NOx, VOC, CO, and PM is based upon corresponding NSPS Subpart III emission standards. SO₂ emissions are based upon fuel flow rate of 104.8 gal/hr and NSPS limit on sulfur content of 500 ppmv. Finally, HAP emissions rates are based upon AP-42 emission factors (Section 3.4 “Large Stationary Diesel and All Stationary Dual-Fuel Engines”, 10/96).

Pollutant	Potential Emissions
	Tons Per Year
PM	0.2
PM-10	0.2
PM-2.5	0.2
NOx	5.3
VOC	5.3
CO	2.9
SO ₂	0.2
Single HAP (Benzene)	0.00279
Total HAP	< 25

This emission source is subject to the requirements of 2D .0521, .0524, and .1111.

15A NCAC 2D .0521 "Control of Visible Emissions"

For sources manufactured after July 1, 1971, visible emissions shall not be more than 20 percent opacity when averaged over a six-minute period. However, except for sources required to install COMs, six-minute averaging periods may exceed 20 percent opacity if:

- (1) No six-minute period exceeds 87 percent opacity;
- (2) No more than one six-minute period exceeds 20 percent opacity in any hour; and
- (3) No more than four six-minute periods exceed 20 percent opacity in any 24-hour period.

The generator is subject to 20 percent opacity limit. The compliance with this requirement will be verified after the commencement of operation.

15A NCAC 2D .0524 "New Source Performance Standards"

Applicability

EPA has promulgated NSPS Subpart IIII "Standards of Performance for Stationary Compression Ignition Internal Combustion Engine" in 71 FR 39154 on July 11, 2006. This NSPS became effective on September 11, 2006. The affected source under the NSPS is each stationary compression ignition (CI) internal combustion engine (ICE) [CI ICE], whose construction, modification or reconstruction commenced after July 11, 2005. The date of construction is the date the engine is ordered by the owner or operator.

Owners and operators of stationary CI ICE that commence construction after July 11, 2005 where the stationary CI is manufactured after April 1, 2006 and is not a fire pump engine, is subject to the requirements of this NSPS as per §60.4200(a)(2).

The Permittee has proposed to construct one 1,500 kW diesel fired emergency generator. It will be driven by CI ICEs to produce power for emergency use only. The generator will commence construction after July 11, 2005 and the engine will have a manufacturing date of 2007 or later. Hence, the proposed generator is subject to the requirements of the NSPS Subpart IIII.

Emission Standards

Because the displacement of emergency CI ICE of the proposed generator is less than 30 liters per cylinder (51.80 liters/12 cylinders = 4.3 liters/cylinder) and the model year of the CI ICE is 2007 or later, the Permittee shall comply with the following emission standards:

NMHC + NO_x: 6.4 g/kW-hr
CO: 3.5 g/kW-hr
PM: 0.2 g/kW-hr

[§§ 60.4205(b) and 60.4202(a)(2), and §89.112(a)]

The Permittee shall use diesel fuel with sulfur content of less than 500 ppm beginning October 1, 2007 in emergency generator (ID Nos. ES-63). The Permittee shall use diesel fuel with sulfur content of less than 15 ppm beginning October 1, 2010 in emergency generator (ID No. ES-63) [§60.4207(a) and (b), and §80.510(a) and (b)].

Monitoring

The emergency generator (ID No. ES-63) shall be equipped with a non-resettable hour meter prior to startup [§60.4209(a)].

If the emergency generator (ID No. ES-63) is equipped with diesel particulate filter to comply with the above emission standards, the Permittee shall install backpressure monitor on diesel particulate filter that notifies the Permittee when the high backpressure limit of the engine is approached [§60.4209(b)].

The Permittee shall operate and maintain CI ICE of emergency generators (ID Nos. ES-63) over the entire life of the engine in accordance with the manufacturer's written instructions or procedures developed by the Permittee that are approved by the engine manufacturer. The Permittee may only change engine settings that are permitted by the

manufacturer. The Permittee shall also meet the requirements of 40 CFR 89, 94 and/or 1068 as applicable [§60.4206 and §60.4211(a)].

For emergency generator (ID No. ES-63), the Permittee shall purchase 2007 model year and later CI ICE, certified to the emission standards in §60.4205(b), for the same model year and maximum engine power. The engine shall be installed and configured according to the manufacturer's specifications [§60.4211(c)].

The Permittee may operate the emergency stationary CI ICE of the emergency generator (ID No. ES-63) for maintenance checks and readiness testing for up to 100 hours per year provided that the tests are recommended by Federal, State, or local government, the manufacturer, the vendor, or the insurance company associated with the engine. Operation during an actual emergency shall not be subject to a limit on hours. The Permittee may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the Permittee maintains records indicating that Federal, State, or local standards require maintenance and testing of emergency ICE beyond 100 hours per year. Because the Permittee is required to comply with emission standards under §60.4205 for CI engines of emergency internal combustion engine and not under §60.4204, any operation other than emergency operation, and maintenance and testing as allowed in §60.4211 is prohibited.

If the emergency stationary CI ICE of each emergency generator (ID No. ES-63) meets the applicable emission standards for non-emergency stationary CI ICE in §60.4204, the limitation on operation of CI ICE (100 hrs per year for maintenance checks and readiness testing) do not apply.

[§60.4211(e)]

Recordkeeping

Starting with the model years in Table 5 to NSPS Subpart IIII, if the emergency stationary CI ICE of the emergency generator (ID No. ES-63) does not meet the standards applicable to non-emergency engines in the applicable model year, the Permittee shall keep records of the operation of the engine in emergency and non-emergency service that are recorded through the nonresettable hour meter. The Permittee shall record the time of operation of the engine and the reason the engine was in operation during that time [§60.4214(b)].

If the emergency stationary CI ICE of the emergency generator (ID No. ES-63) is equipped with diesel particulate filters, the Permittee shall keep records of any corrective action taken after the backpressure monitor has notified the Permittee that the high backpressure limit of the engine is approached [§60.4214(c)].

Reporting

No initial notification under §60.7(a)(1) and (a)(3) is required for emergency stationary CI ICE of the emergency generator (ID No. ES-63) [§60.4214(b)].

15A NCAC 2D .1111 "Maximum Achievable Control Technology"

Applicability

EPA has promulgated MACT Subpart ZZZZ "National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines (RICE MACT)" in 69 FR 33506 on June 15, 2004 with an effective date of August 16, 2004. This MACT was revised at 73 FR 3603 on Jan. 18, 2008.

The MACT applies to RICE located at a major or an area source of HAP emissions with a site-rating of less, equal to or greater 500 BHP.

A stationary RICE located at an area source of HAP emissions is "new" if you commenced construction of the stationary RICE on or after June 12, 2006.

The RICE of the proposed generator will have a site-rating of 1,500 kW or 2,011 HP and will be located at an area source of HAP emissions (See Section 8 below for HAP emissions), and it will be constructed after June 12, 2006. Hence, the emergency generator is deemed “new” affected source at an area source under this Subpart. Hence, it will be required to demonstrate compliance with the MACT upon startup.

If the stationary RICE located at an area source is subject to NSPS Subpart IIII requirements, then the RICE must meet the requirements of MACT Subpart ZZZZ by meeting all applicable requirements under NSPS Subpart IIII. No further requirements apply to such engines under MACT Subpart ZZZZ. Refer to §63.6590(c).

As discussed above, the proposed RICE is also subject to NSPS Subpart IIII requirements. Hence, no additional requirements under this MACT shall apply.

6.4 To move the existing generator (ID No. ES-17) to a different location of the facility.

The existing generator (ID No. ES-17, 750 kW) is currently located at Yarborough Steam Plant and the Permittee wishes to relocate it to Cates Steam Plant. The change in location for this existing generator does not require any permit review. The generator is currently subject to the requirements in 2D .0516 and .0521, and 2Q .0317, and it will continue to be subject to these requirements.

6.5 Other

The Permittee wishes to remove insignificant activity IES-60E (200 kW emergency generator) from the permit.

No action is needed as this generator has already been removed at the time of issuing the current permit 02977T18.

7. NSPS, NESHAPS, PSD, Attainment Status, 112(r), CAM

NSPS

Refer to Section 6.1 through 6.3 above for NSPS applicability for the proposed equipment.

NESHAPS

Refer to Section 6.3 above for NESHAPS (MACT) applicability for the proposed emergency generator.

PSD and ATTAINMENT STATUS

The County of Wake is in attainment of NAAQS for all criteria pollutants. Hence, PSD program applies in this County to all major sources and major modifications.

NCSU is a “250 tons” industrial category source. The facility is currently a “minor” source for PSD. Any modification, which in itself is “major”, must be reviewed for PSD under “major source” provisions.

The following is a summary of the project emissions. This summary includes potential to emit emissions of each of the new emission sources as discussed in Section 6.1 through 6.4 above.

It should be noted here that the Permittee has decided not to exclude baseline actual emissions of the replaced units (existing boilers as discussed in Section 6.1 and 6.2 above, which are proposed to be removed with this permit modification) from the project emissions.

Regulated NSR Pollutant	Potential Emissions Tons per Year
PM	115.6

PM10	115.6
SO ₂	559.9
NO _x	510.9
CO	212.7
VOC	105.7

As can be seen in the above emission summary, the project emissions for NO_x and SO₂ exceed major source threshold while emissions of PM/PM10, CO, and VOC exceed their respective significance thresholds. Hence, PSD “major source” review is required for all of the above pollutants. However, in accordance with §51.166(h)(4)(i), PSD provisions in §51.166(j) through (r) are not applicable to any “major source” or “major modification” at a non-profit educational institution. Thus, the proposed changes are NOT subject to the following requirements:

§51.166(j) “Control Technology Review”

§51.166(k) “Source Impact Analysis”

§51.166(l) “Air Quality Models”

§51.166(m) “Air Quality Analysis”

§51.166(n) “Source Information”

§51.166(o) “Additional Impact Analysis”

§51.166(p) “Sources Impacting Federal Class I Areas-Additional Requirements”

§51.166(q) “Public Participation”

§51.166(r) “Source Obligation”

Although the Permittee is exempt from the modeling requirements under PSD; specifically §51.166(m) and (p), DAQ has exercised its discretionary authority to require modeling demonstration to show compliance with SO₂ NAAQS. AQAB reviewed the NCSU submitted modeling analysis and concluded through memorandum dated May 7, 2009, “The modeling analysis did demonstrate compliance with the NAAQS for SO₂.”

The following is a summary of this analysis:

Pollutant	Modeled Impact ug/m ³	Background ug/m ³	Modeled Impact + Background ug/m ³	NAAQS ug/m ³	Percent of NAAQS
SO ₂	793	34	827	1300 (3-hr)	64
SO ₂	272	16	288	365 (24-hr)	79
SO ₂	62	5	67	80 (annual)	84

The revised permit will include PSD as an applicable requirement without any substantive requirement for all new equipment: boilers (ID Nos. ES-2A, ES-3A, and ES-4A), combustion turbines (ID Nos. ES-1A and ES-1B), and emergency generator (ID No. ES-63).

Finally, for increment tracking purposes, the emissions of PM-10, SO₂, and NO₂ have increased by 26.4 lbs/hr, 127.8 lbs/hr, and 116.6 lbs/hr, respectively, due to proposed modifications.

112(r)

This facility is not subject to Section 112(r) of the Clean Air Act requirements.

CAM

CAM applicability review is not required at this time for the proposed modification. Because the changes are being reviewed under the provision of 2Q .0501(c)(2) - essentially 2Q .0300 procedures are followed for this permit revision. Moreover, none of the proposed changes involve any "active" control devices.

8. Facility Wide Air Toxics

The proposed boilers, combustion turbines, and emergency generator are deemed “combustion sources” pursuant to 2Q .0703(6). In accordance with 2Q .0702(a)(18), air toxics emissions from these “combustion sources” are exempt from review under NC’s air toxics program.

9. Facility Emissions Review

The following Table includes facility wide actual emissions summary for 2007. Emissions estimate for potential emissions is not available.

Pollutant	Actual Emissions
	tons/year
Particulate (TSP)	11.7
Particulate (PM-10)	8.7
Particulate (PM-2.5)	4.8
Carbon Monoxide	62.7
Nitrogen Oxides	116.5
Sulfur Dioxide	86.2
Volatile Organic Compounds	6.2
Single largest HAP (HCl)	1.22
Total HAP	1.32

10. Stipulation Review

The following changes were made to NCSU Air Quality Permit No. 02977T19:

Old Page No. [Air Quality Permit No. 02977T19]	New Page No. [Air Quality Permit No. 02977T20]	Condition No.	Changes
3	3	Section 1 Table	Include new equipment: ES-1A, ES-1B, ES-2A, ES-3A, ES-4A, and ES-63. Modify descriptor for ES-17 to state that it is located at “Cates Steam Plant”.
Various	Various	Entire Permit	Modify the “facility wide” to state “facility-wide (except ID Nos. ES-1A, ES-1B, ES-2A, ES-3A, ES-4A, ES-61, ES-62, and ES-63)”. Note: Emissions of sources ES-61 and ES-62 should have been excluded from facility-wide emissions requirements under PSD and NAA NSR avoidance in permit 02977T18, but they were not. The new sources (ES-1A, ES-1B, ES-2A, ES-3A, ES-4A, and ES-63) in this permit revision are subject to PSD review so these sources need to be excluded from facility wide emissions calculations for PSD and NAA NSR avoidance conditions.
-	31 through 37	Section 2.1 K.	Include this new Section for three new boilers (ES-2A, ES-3A, and ES-4A).

-	37 through 45	Section 2.1 L.	Include this new Section for two, new turbines (ES-1A and ES-1B).
-	45 through 49	Section 2.1 M.	Include this new Section for new emergency generator (ES-63).

11. Public Notice / EPA and Affected States Review

Public participation and EPA review are not required for any permit revision processed under 2Q .0300.

12. Conclusions, Comments, and Recommendations

- The proposed modifications do not involve installation of any new control device or modification of any existing control device. PE seal requirement is not applicable in 2Q .0112.
- City of Raleigh has determined via letter dated 12/12/08 that “The addition of steam boilers and generators on a university campus is consistent with the zoning of this area.”
- The draft permit was e-mailed to Charles McEachern of RRO on June 29, 2009 for review and comments. Dena Pittman of RRO emailed on 6/30/09 with the following: “I did not see any issues with this permit or review. RRO recommends issuance of the permit.”
- The draft permit was also e-mailed to the company on June 29, 2009 for review and comments. The NCSU comments were received from RO on July 10, 2009 (unofficial comments were received via email from Jeff Hightower of NCSU on 7/6/09). The NCSU comments and the DAQ response are as follows in the same order:

Comment 1:

“If possible could you please ad the term "nominal" to the heat input of the proposed boilers and to the heat input of the proposed combustion turbines.”

DAQ Response:

DAQ will insert the prefix “nominal” before “heat input rate” and also change “maximum” to “nominal”, as needed, to the descriptors of new boilers and combustion turbines.

Comment 2:

“If possible could you please mention that the boilers will be installed in phases and that there will be a period of time to transition from the existing boilers to the proposed boilers.”

DAQ Response:

Rahul discussed this comment with John Evans of this office.

In this permit application, the Permittee had requested to remove the existing boilers (ID Nos. ES-01 through ES-04) and replace them with new turbines and boilers (ID Nos. ES-1A, ES-1B, ES-2A, ES-3A, and ES-4A). See Section 6.1 and 6.2 above.

Since, NCSU is not using netting analysis (increases from the new (replacement) emissions units and decreases from the shut-down (replaced) units) for this PSD project to “net-out” from PSD requirements, there is no need to remove the replaced boilers from the air permit. The company can continue operating the above existing boilers and thus, DAQ will keep them in the permit.

NCSU can submit in future a permit application to remove the above boilers from the permit when they are replaced with new turbines and boilers. In brief, these replaced (existing) units will be kept in the air permit

until the replacement (new) units commence operation and the Permittee specifically requests to remove these replaced units from the air permit.

DAQ (Rahul Thaker) has advised accordingly to NCSU (Jeff Hightower).

Comment 3:

“Please change "duel-fuel" to "dual-fuel.””

DAQ Response:

Agreed. This change will be made to the draft permit.

Comment 4:

“We had understood that the Facility ID No.was 9200290, however, the last several permits have listed 9200500.”

DAQ Response:

Agreed.

The current air permit 02977T19 includes incorrect facility ID “9200500” on Page 1 while it includes the correct facility ID “9200290” on the cover letter. The draft permit also has this error. The revised air permit will include the correct ID number on both the cover letter and the 1st page of the air permit.

Comment 5:

“If possible could the following be added to the 2. Facility Description: "Finally, the entire NCSU campus is currently considered minor for NSR review purposes since potential emissions of each regulated compound are limited in the existing permit to 250 tons per year or less; however, the fossil fuel-fired boilers are major for NSR review purposes since the cumulative total heat input is greater than 250 MMBtu/hr and the potential emissions are greater than 100 tons per year. it is an existing minor source for Prevention of Significant Deterioration (PSD).””

DAQ Response:

This change will not be made to the draft permit review.

Comment 6:

“If possible please change the last sentence after the table in 6.1 to "Each of the boilers is subject to the requirements of 2D .0503, .0521, and .0524, and .0530.””

DAQ Response:

Agreed. This change will be made to the draft permit review.

- Finally, this engineer recommends issuing the final permit upon conclusion of the review period.