MEMORANDUM

AUG 2 2 2002
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TO: Robert J. Taggart

THROUGH: Nancy E. Terranova NET

FROM: Thomas I. Lilly TIL
Brian K. Hurd BKH by NET

SUBJECT: Indian River Power, LLC, Indian River Generating Station
Technical Memorandum, Regulation No. 30 Permit
Permit: AQM-005/00001

DATE: August 9, 2002

Background Information

Delmarva Power and Light Company (DP & L) owned and operated the Indian River Power Plant. On June 22, 2001 the plant was sold to NRG Thermal Corporation which indicated, according to the revised Title V permit application, Indian River Power, LLC (Company) as the owner of the now named Indian River Generating Station (Facility). This Facility, located on Power Plant Road near Millsboro, Sussex County, Delaware, is a major stationary source subject to Regulation No. 30 because the Facility has emissions of 100 tons per year or more of the following regulated pollutants: sulfur dioxide (SO_2), nitrogen oxides (NOx), particulate and a combination of hazardous air pollutants (HAPs).

DP & L submitted an AQM-1001 series application, dated January 2, 1997. The original application was determined to be timely and was deemed to be administratively complete on March 3, 1997. A revised application was submitted by the Company and received by the Department, dated June 11, 2002.

Based on the AQM - 1001 series application dated January 2, 1997 and June 11, 2002:
- The Company is not subject to the requirements of Section 112(r) of the 1990 Clean Air Act.
- The Company has not registered with the State of Delaware "Regulations for the Management of Extremely Hazardous Substances".
- Title VI of the 1990 Clean Air Act is applicable to this Facility.

The Company is current with applicable Regulation No. 30 Fees.

The responsible official is Gerry Hopper, Plant Manager, Indian River Operations, Inc.

The Regulation No. 30 correspondence chronology is listed in the table below.

ITEM	DATE
AQM Series application dated January 2, 1997	Received January 2, 1997
Letter to Company - application deemed complete (application shield granted)	March 10, 1997
Letter from Company - change of designated representative and alternate Designated Representative	Received March 25, 1998
Acid Rain Phase II Permit AQM-005/00001-IV issued May 20, 1998 (expiration date, 4/20/03)	May 20, 1998
Acid Rain Phase II Permit Administrative Amendment AQM-005/00001-IV issued May 20, 1998 (expiration date, 4/20/03)	September 14, 2001
Revised AQM Series application dated June 11, 2002	Received June 11, 2002

General

Indian River Power, LLC (the "Company") is the owner of the Indian River Generating Station (the "Facility"). The Facility is operated by Indian River Operations, Inc. (the "Operator") The business at this Facility is electric power generation, the Standard Industrial Classification (SIC) for the Facility is 4911 and the North American Industry Classification System Code (NAICS) is 221112 for Fossil Fuel Electric Power Generation. The Company operates four (4) coal fired steam production boilers and one (1) combustion gas turbine. Emission units at the Facility include the coal and ash handling system, fuel oil storage tanks, used oil heater, parts cleaners, lime silo and baghouse.

The applicable requirements specific to this Facility are Regulation No. 2, 4, 5, 6, 8, 10, 12, 14, 15, 17, 19, 20, 24, 25, 30, 36, 37 and 39. The applicable sections of Regulation 24 are 6, 8, 26, 31, 33 and 49. 40 CFR Part 60 Subpart D, Subpart Y and 40 CFR Parts 72 through 78 are applicable to this Facility. Section 112(n) of the Clean Air Act Amendments of 1990 required the Administrator of the EPA to study the hazards that occur as a result of emissions of 112(b) pollutants by electric utility steam generating units, in particular emissions of the hazardous air pollutant (HAP) mercury. To date there are no applicable requirements for HAP emissions from these units.

The Facility is located near Millsboro, Sussex County and is a major source of sulfur dioxide, nitrogen oxide and particulate matter. Aggregate HAP emissions from the Facility's combustion processes is estimated at greater than 25 tons per year.

The four utility boilers at the Facility are subject to the Provisions of the Acid Rain Regulations (40 CFR Parts 72 -78 and Delaware Regulation No. 36). The Acid Rain Provisions include requirements for permitting (Part 72), limiting (Part 76) and monitoring (Part 75) NOx emissions.

The Company is subject to Regulation No. 37, *NOx Budget Program*, which requires the Company to have NOx allowances (one allowance equals one ton) equal to the amount of NOx emitted through the period from May 1 to September 30, the Ozone Season, in its possession at the end of each calender year of 1999 through 2002.

The Company is subject to Regulation No. 39, *Nitrogen Oxides Budget Trading Program*, which requires the Company to have NOx allowances (one allowance equals one ton) equal to the amount of NOx emitted through the period from May 1 to September 30, the Ozone Season, in its possession at the end of each calender year of 2003 through 2005.

The identified NOx applicable requirements have been incorporated into the Regulation No. 30 operating permit in Condition 3-Table 1 as either a separate section or within the emission unit section.

40 CFR Part 63, Subpart T, National Emission Standards for Halogenated Solvent Cleaning, does not apply to the cold solvent degreaser (cleaner). The solvent used in the degreaser is Safety-Kleen Premium Solvent and is not a halogenated solvent, based on the Subpart T definition. This definition states that the halogen content of the solvent must be greater than five (5) percent by weight.

40 CFR Part 64 *Compliance Assurance Monitoring* (CAM) will apply to the electrostatic precipitators for particulate emissions from Emission Units 1, 2, 3 and 4 since each emission unit has a potential to emit greater than the major source threshold. In accordance with 40 CFR Part 64.5(a)(3), the Company must submit Compliance Assurance Monitoring with the renewal application for the Title V Permit.

The Company has identified eighteen (19) emission units and six (6) insignificant activities in the June 11, 2002 AQM-1001 series application. The numbering system employed by Indian River Power, LLC in their AQM-1001 series application is not in any specific order, therefore the Department has renumbered the emission units as identified in the following table.

Emission Units	Emission Unit Description
1	Boiler No. 1, net capacity of approximately 91.0 MWe and a nominal heat input of 1,090 MMBTU/hr, fired on coal and No. 2 fuel oil. (Indian River Unit IR 1).
2	Boiler No. 2, net capacity of approximately 91.0 MWe and a nominal heat input of 1,186 MMBTU/hr, fired on coal and No. 2 fuel oil. (Indian River Unit IR 2)
3	Boiler No. 3, net capacity of approximately 165.0 MWe and a nominal heat input of 1,904 MMBTU/hr, fired on coal and No. 2 fuel oil. (Indian River Unit IR 3)
4	Boiler No. 4, net capacity of approximately 420.0 MWe and a nominal heat input of 5,091 MMBTU/hr, fired on coal and No. 2 fuel oil. (Indian River Unit IR 4)
5	Combustion Gas Turbine, a Pratt & Whitney FT4-9LF 366 MMBTU/hr Turbo-Jet Power Pak Fuel: No. 2 fuel oil and Low Sulfur Liquid Petroleum Product (LSLPP) (Indian River Unit IR 10)
6	Ash Landfill Garage Heater , a Clean Burn CB - 2000 Fuel: Waste oil - max: 1.3 gallons per hour (Indian River Unit IR 20)
7	Ash Handling/Fly Ash Silo (Indian River Unit IR 76)
8 & 9	Vacuum Fly Ash Transfer with Filter Receivers for Boilers 1, 2 & 3 (Indian River Units IR 77 & IR 78)
10	Lime Silo and Lime Silo Baghouse (Indian River Unit IR 79)
11	Fuel Oil Tank (No. 2 fuel oil) a 10,000 gallon tank (Indian River Unit IR 75)
12	Fuel Oil Tank #1/(No. 2 fuel oil) a 250,000 gallon fixed roof storage tank; installed 1967 (Indian River Unit IR 101)
13	Fuel Oil Tank #2/(No. 2 fuel oil) a 250,000 gallon fixed roof storage tank; installed 1967 (Indian River Unit IR 102)
14 & 15	Gasoline Dispensing (Indian River Units IR 74 & IR 104)
16 & 17	Coal Pile and Coal Handling (Indian River Unit IR 109 & IR 110)
18	Ash Landfill (Indian River Unit IR 111)
19	Cold Solvent Parts Cleaner (Indian River Unit IR 205)

The following table lists existing Regulation No. 2 permits with a description.

Existing Regulation No. 2 Permits	Description
APC-81/0906-OPERATION-Amendment 2 (NOx RACT) dated August 29, 2001 (EU 1)	A Babcock and Wilcox steam boiler, designated Boiler No. 1, having a net capacity of approximately 91.0 MWe and a nominal heat input of 1,090 MMBTU/hr, fired on coal and No. 2 fuel oil and equipped with Low NOx burner, low excess air, overfire air, and associated Research Cottrell electrostatic precipitator.

Existing Regulation No. 2 Permits	Description
APC-81/0905-OPERATION- Amendment 2 (NOx RACT) dated August 29, 2001 (EU 2)	A Babcock and Wilcox steam boiler, designated Boiler No. 1, having a net capacity of approximately 91.0 MWe and a nominal heat input of 1,186 MMBTU/hr, fired on coal and No. 2 fuel oil equipped with Low NOx burner, low excess air, overfire air, and a Research Cottrell electrostatic precipitator.
APC-81/0660-OPERATION- Amendment 3 (NOx RACT) dated February 12, 2002 (EU 3)	A Babcock and Wilcox natural circulation, radiant, reheat, balanced draft type boiler, designated Boiler No. 3, having a net capacity of approximately 165.0 MWe and a nominal heat input of 1,904 MMBTU/hr, fired on coal and No. 2 fuel oil equipped with Low Nox burners, low excess air, overfire air, selective non-catalytic reduction (SNCR), and a electrostatic precipitator.
APC-82/0149-OPERATION- Amendment 4 (NOx RACT) (NSPS) dated February 12, 2002 (EU 4)	A Riley Stoker dry bottom "Turbo Furnace" steam boiler, designated Boiler 4, having a net capacity of approximately 420.0 MWe and a nominal heat input of 5,091 MMBTU/hr, fired on coal and No. 2 fuel oil equipped with Low Nox burners, low excess air, overfire air, underfire air, selective non-catalytic reduction (SNCR), and a electrostatic precipitator.
APC 93/0461 OPERATION- Amendment 1 dated August 29, 2001 (EU 5)	Distillate No. 2 fuel oil fired Pratt & Whitney FT4A - 9 Turbo Jet Power Pac Combustion Gas Turbine, heat input 366 MMBTU/hr, installed in May, 1967.
APC 95/519 CONSTRUCTION/ OPERATION- Amendment 1 dated August 29, 2001 (EU 6)	One (1) Clean Burn CB - 2000 waste oil furnace having a maximum heat input of 0.185 MMBTU/hour and fueled with used oil at the maintenance building, located at the ash disposal site.

DP&L originally listed the following processes and units as insignificant activities, however the units have applicable requirements and the Company listed them as emission units in the revised Title V application. IR 74, Gas Tank - Vehicle Fleet Fueling, as stated in the January 2, 1997 application, is identified as Emission Unit 14 - Gasoline Dispensing subject to Regulation No. 24 Section 26. IR 75, Diesel Tank - Vehicle Fleet Fueling, from the January 2, 1997 application, is identified as Emission Unit 11 - Fuel Oil Tank subject to Regulation No. 24 Section 49. These units are included in the Regulation No. 30 operating permit with the emission unit numbers mentioned above. Based on the size rate of less than 40,000 gallons given in the January 2, 1997 application, IR 103 - Fuel Oil Tanks would have been subject to Regulation No. 24 Section 49, however, the June 11, 2002 application identifies IR 103 with a size rate of less than 250 gallons. Therefore, IR 103 - Fuel Oil Tanks is included in this Regulation No. 30 permit as an insignificant activity. In the revised application the Company indicated that the Facility has a laboratory emitting less than 450 lbs. VOCs per month and four (4) VOC free parts cleaners (IR 201 through IR 204) as insignificant activities. A new cold solvent cleaner designated as IR 205 has been added and is included as Emission Unit 19 in the Title V permit.

Insignificant Activity	Basis for Determination
Oil Tanks	Size < 250 gallons
Four (4) SmartWashers "Parts Cleaners"	Emission rate - Solvent contains < 5% VOCs
IR 100 - Boiler Chemistry/Sample analysis Lab	Emission rate < 10 lbs/day

Technical Review and Applicable Requirements Discussion

Emission Unit 1, One (1) nominal rated 1090 MMBTU/hr steam production boiler fired primarily on coal. Secondary and emergency fuels are No. 2 fuel oil and Lower Sulfur Liquid Petroleum Product(LSLPP)
Emission Unit 2, One (1) nominal rated 1186 MMBTU/hr steam production boiler fired primarily on coal. Secondary and emergency fuels are No. 2 fuel oil and LSLPP.
Emission Unit 3 - One (1) nominal rated 1904 MMBTU/hr steam production boiler fired primarily on coal. Secondary and emergency fuel is No. 2 fuel oil.
Emission Unit 4 One (1) nominal rate 5091 MMBTU/hr steam production boiler primarily fired on coal. Secondary and emergency fuel is No. 2 fuel oil.

Emission Units 1 through 4 are boilers with many of the same applicable requirements. The following section discusses the applicable requirements that are the same for each unit. Specific applicable requirements for each unit are discussed in the individual sections.

These emission units are subject to Regulation No. 4, *Particulate Emissions from Fuel Burning Equipment.* Particulate emissions are limited to 0.3 pound per million BTU heat input on a maximum two (2) hour average. The Company is in compliance with Regulation No. 4 because at the maximum firing rate the emission of particulate matter does not exceed 0.3 lb/MMBTU with the ESPs operating at the rated efficiency for Units 1, 2, 3 and 4. Unit 4 is also required to not exceed 0.1 lb/MMBTU to be in compliance with an NSPS limitation.

The particulate matter emission factor from AP-42 is 10(A) pounds per ton of coal burned and "A" indicates the weight % of ash in the coal. The average heat content in BTU per pound of coal is given as 13,000 BTU/lb. The following calculations demonstrate particulate matter emissions at the one hour maximum firing rate when fired on coal with a sulfur content of 1.6% and an ash content of 12% as the worst case scenario for Units 1, 2 and 3. For Unit 4 the worst case scenario is when fired on coal with a sulfur content of 0.75% (approximate equivalent of 1.2 pounds per MMBTU) and an ash content of 11%.

Pre-Control Particulate Emissions:

Emission Units 1

$$\text{Maximum coal usage} = \frac{1090\ \text{MMBTU}}{\text{hr}} \times \frac{\text{lb}}{0.013\ \text{MMBTU}} \times \frac{\text{ton}}{2000\ \text{lb}} = \frac{41.9\ \text{tons coal}}{\text{hr}}$$

$$\text{Maximum particulate emission} = \frac{\text{hr}}{1090\ \text{MMBTU}} \times \frac{10\ (12)\ \text{lb}}{\text{ton}} \times \frac{41.9\ \text{tons}}{\text{hr}} = \frac{4.6\ \text{lb}}{\text{MMBTU}}$$

Emission Units 2

$$\text{Maximum coal usage} = \frac{1186\ \text{MMBTU}}{\text{hr}} \times \frac{\text{lb}}{0.013\ \text{MMBTU}} \times \frac{\text{ton}}{2000\ \text{lb}} = \frac{45.6\ \text{tons coal}}{\text{hr}}$$

$$\text{Maximum particulate emission} = \frac{\text{hr}}{1186\ \text{MMBTU}} \times \frac{10\ (12)\ \text{lb}}{\text{ton}} \times \frac{45.6\ \text{tons}}{\text{hr}} = \frac{4.6\ \text{lb}}{\text{MMBTU}}$$

Emission Unit 3

$$\text{Maximum coal usage} = \frac{1904\ \text{MMBTU}}{\text{hr}} \times \frac{\text{lb}}{0.013\ \text{MMBTU}} \times \frac{\text{ton}}{2000\ \text{lb}} = \frac{73.2\ \text{tons coal}}{\text{hr}}$$

$$\text{Maximum particulate emission} = \frac{\text{hr}}{1904\ \text{MMBTU}} \times \frac{10\ (12)\ \text{lb}}{\text{ton}} \times \frac{73.2\ \text{tons}}{\text{hr}} = \frac{4.6\ \text{lb}}{\text{MMBTU}}$$

Emission Unit 4

$$\text{Maximum coal usage} = \frac{5091\ \text{MMBTU}}{\text{hr}} \times \frac{\text{lb}}{0.013\ \text{MMBTU}} \times \frac{\text{ton}}{2000\ \text{lb}} = \frac{195.8\ \text{tons coal}}{\text{hr}}$$

$$\text{Maximum particulate emission} = \frac{\text{hr}}{5091\ \text{MMBTU}} \times \frac{10\ (11)\ \text{lb}}{\text{ton}} \times \frac{192.8\ \text{ton}}{\text{hr}} = \frac{4.23\ \text{lb}}{\text{MMBTU}}$$

The particulate emissions from each boiler are controlled by an induced draft electrostatic precipitator. The ESP for Units 1 and 2 was designed and fabricated by Research Cottrell, Inc. Belco Pollution Control designed the ESP for Unit 3 and Lodge-Cottrell was the designer for Unit 4. The efficiency of the ESP units for Units 1, 2 and 3 is given as 98.5% and 99.5% for Unit 4. The following equations demonstrate compliance with the Regulation No. 4, *Particulate Emissions from Fuel Burning Equipment* standard of 0.3 lb/MMBTU for Units 1, 2, 3 and 4 and the 0.1 lb/MMBTU for Unit 4 with the ESPs operating at the rated efficiencies.

Post-Control Particulate Emissions
Emission Units 1, 2 and 3

$$\text{Maximum particulate emissions with ESP at 98.5\%} = \frac{4.6\ \text{lb}}{\text{MMBTU}} \times (1 - 0.985) = \frac{0.07\ \text{lbs}}{\text{MMBTU}}$$

Emission Unit 4

$$\text{Maximum particulate emissions with ESP at 99.5\%} = \frac{4.23\ \text{lb}}{\text{MMBTU}} \times (1 - 0.995) = \frac{0.02\ \text{lbs}}{\text{MMBTU}}$$

Monitoring requirements for Units 1 & 2 control equipment operation include monitoring of the electrostatic precipitator operating parameters, continuously. Monitoring requirements for Units 3 & 4 control equipment operation include monitoring the electrostatic precipitator operating parameters at least once per shift. Those parameters include the primary and secondary voltage, the primary and secondary current and the spark rate. The primary voltage and current data concern the 480 volt AC power supply to the transformer rectifier sets (T-R set). The secondary voltage is the voltage leaving the T-R set and on the discharge electrode of the ESP. The secondary current is the direct current flow from the T-R set that passes through the field. The spark rate is the number of short term arcs that jump between the discharge electrode and the collection plates in the field. These requirements have been incorporated into the Regulation No. 30 operating permit.

Stack testing which demonstrates compliance with the particulate emission standard of Regulation No. 4, *Particulate Emissions from Fuel Burning Equipment* shall be conducted for each emission unit once each permit term. Particulate removal efficiency testing requirements have been incorporated into the permit in Condition 3-Table 1. The last ESP particulate removal efficiency test on Units 1 & 2 was conducted in 1982, Unit 3 was tested in 1981 and Unit 4 was tested in 1991. Condition 3-Table 1 of the operating permit requires the Company to conduct Department approved stack testing. The Company shall demonstrate compliance with Regulation No. 4 within 120 days of the date of expiration of this operating permit. In addition to testing, Condition 3-Table 1 of the operating permit requires specific operating parameters of the ESP to be monitored and have records maintained, these parameters include: inlet gas temperature, primary and secondary voltages, primary and secondary current and the spark rate.

A 1989 Conciliatory Order required that the Facility not receive coal with a sulfur content greater than 1.6% by weight. Compliance with this limitation is demonstrated through a coal sampling and analysis program that follows US EPA Reference Method 19. The results of the sample analysis for the coal received each month are to be reported to the Department within 60 days of the end of that month. This coal can be combusted in Units 1, 2 and 3 only. These requirements have been incorporated into the permit in Condition 3-Table 1(a)(3) and (b)(3).

Regulation No. 8, *Sulfur Dioxide Emissions from Fuel Burning Equipment*, is applicable to these emission units. There are no SO_2 control devices installed on these units. When firing coal, emissions are controlled with a pre-combustion restriction by firing of coal with a sulfur content not to exceed 1.6% by weight for Units 1, 2 and 3. Compliance is based on sampling and testing the coal for sulfur content. Unit 4 is subject to an NSPS that restricts the sulfur dioxide emissions to not exceed 1.2 lb/MMBTU. Any No. 2 fuel oil combusted in these units is to have a sulfur content not to exceed 0.3% by weight. Compliance with this limitation is based upon fuel suppliers' certification for No. 2 fuel oil. For Unit 4, compliance shall be based upon the 1.2 lb SO2/MMBTU, monitored by the CEM. This requirement is in Condition 3 - Table 1(c)(3)(iii) and (c)(3)(v) of the Regulation No. 30 operating permit.

Regulation No. 14, *Visible Emissions*, is an applicable requirement for these emission units. Compliance with the emission limitation will be demonstrated by the use of a continuous opacity monitoring system (COMS) operated in accordance with Regulation No. 17, *Source Monitoring, Record Keeping, and Reporting*. The COMS shall meet all requirements set forth in Performance Specification 1 of 40 CFR Part 60, Appendix B. In addition to meeting PS-1 requirements, the cycling time and the zero and span drift in the CMS shall meet the requirements set forth in 40 CFR Part 51, Appendix P. These requirements have been incorporated into the Regulation No. 30 Operating Permit.

The Company has requested, through the AQM-1001 series application, the authorization to burn supplemental fuels in each unit at Indian River, which include waste and used oils and petroleum contaminated soils. The requirements for burning and handling supplemental fuels were taken from the Delaware Regulations Governing Hazardous Waste (DRGHW) and Regulation No. 22, *Restrictions on the Quality of Fuel in Fuel Burning Equipment*. The restrictions and conditions listed in Condition 3 - Table 1(p)(5) for facility wide in the Regulation No. 30 operating permit include the following conditions:

- Only DP&L generated contaminated soils will be burned.
- The weight of all contaminated soil received or stored at the site shall be recorded and maintained.
- Stockpiling of contaminated soils shall be limited to 500 tons. Amounts greater than 500 tons shall be burned within three (3) months from the date greater than 500 tons was accumulated on site.
- Contaminated soils shall be blended with coal at a rate not to exceed 10% soil to coal.
- Contaminated soils shall be stored in diked area adjacent to the coal pile.

These boilers are subject to Regulation No. 36, *Acid Rain Provisions,* which include the federal Phase II Acid Rain requirements (group I boilers). The Company has installed and is operating certified monitoring equipment for the following: sulfur dioxide, nitrogen dioxide, carbon dioxide, flue gas flow and opacity. Regulation No. 36 and 40 CFR Part 76 limit nitrogen oxide emissions form each boiler to 0.46 lb/MMBTU heat input averaged on an annual basis. This emission limitation has been included in the Regulation No. 30 operating permit as Condition 3 - Table 1(a)(4)(i)(C), b(4)(i)(B) and c(4)(i)(E). The Company agreed to a nitrogen oxide emission limit of 0.39 lb/MMBTU heat input on an annual basis for Emission Unit 4. The Regulation No. 36 permit will be reissued and is included as an enclosure to the Regulation No. 30 operating permit as required by the Acid Rain Program. The requirements of the regulation are incorporated into the permit in Condition 3-Table 1.

The Company is required to comply with Regulation No. 37, *NOx Budget Program.* This is a Facility wide applicable requirement that is State Enforceable Only until the State Implementation Plan (SIP) is approved. These Regulation No. 37 requirements have been met. The Company has certified an authorized account representative for the Company, has submitted documentation to open a compliance account for the NOx Tracking System and has submitted updated monitoring plans with modified heat input calculations for each affected unit. The units were not required to install additional emission monitoring equipment. The Account Certificate of Representation has been evaluated and approved. The NOx Allowance Tracking System (NATS) Administrator was notified by letter and authorized to open a compliance account for the Facility. Beginning in May 1999, compliance with this regulation requires the Company to have in its possession an equal number of NOx allowances as the tons of NOx emitted through the ozone season, at the end of each calender year (December 31). This account must be balanced by December 31 each year or the non-compliance conditions of repayment of three (3) allowances for every one (1) short must be returned to the NATS administrator. The Company submitted the regulation required NOx monitor plan updates which include formula verification that demonstrate the data acquisition system accurately calculates and reports the NOx mass emission rate based on hourly heat input and NOx emission rate. The requirements of Regulation No. 37 have been incorporated into the permit in Condition 3-Table 1(k).

These boilers are subject to Regulation No. 39, *Nitrogen Oxides (NOx) Budget Trading Program.* The Regulation No. 39 permit was issued May 1, 2002. The permit is included as an enclosure to the Regulation No. 30 permit as required by the NOx Budget Trading Program.

Specific Applicable Requirements: Emission Units 1, 2, 3 and 4

Emission Unit 1 and Emission Unit 2

In 1957, at the Indian River Power Plant, Delmarva Power placed into service Unit 1, a Babcock & Wilcox coal fired boiler which has a maximum nominal heat input rating of 1090 MMBTU/hr. In 1959, Unit 2, a Babcock & Wilcox coal fired boiler with a maximum nominal heat input rating of 1186 MMBTU/hr, was placed into service. Maximum nominal heat input ratings are based on fuel consumption. Each unit produces steam to each power an 91 MWe electric generator.

Each unit is a dry bottom, wall mounted burner, balanced draft type boiler designed to fire bituminous coal as the primary fuel through three elevations of three front wall mounted burners. The units are able to fire No. 2 fuel oil concurrently with coal from all nine burners and also as a secondary or emergency fuel. Each unit is equipped with a Research Cottrell, Inc. electrostatic precipitator. Each boiler exhausts through an individual chimney in a 500 feet tall, two flue, stack.

Between 1980 and 1985, the Company monitored SO_2 emissions and documented exceedances at one of its ambient air monitoring stations. It was discovered that the exhaust gas from Units 1 and 2 were being impacted by building downwash from the building around Unit 3. In an effort to reduce ambient levels of SO_2 the Department issued a Notice of Conciliation which required the Company to implement a sulfur emission reduction strategy or install a tall stack. Two 500 foot (GEP formula height) co-located stacks were constructed enclosed in one shell and placed into service in 1992.

Regulation No. 12, *Control of Nitrogen Oxide Emissions*, requires that any source subject to the Regulation shall not emit NOx from affected units without the use of reasonably available control technology (RACT). Section 3.2(b) required that the Company install low NOx burners with low excess air and overfire air on each emission unit. The emission limits after installation of the required equipment are determined based on a rolling twenty-four (24) hour average period. Based on CEMs data for Emission Unit 1 submitted to EPA in conjunction with the Acid Rain Program, the low NOx burners and other equipment were installed by November 7, 1998. The year 1999 was selected to determine the rolling twenty-four (24) hour average nitrogen oxide emissions limit for the boiler. In 1999 the maximum rolling twenty four (24) hour average nitrogen oxide emissions were 0.54 pound per MMBTU heat input. To assure proper operation of the low NOx burner installation, the Department selected the 95th percentile or 0.49 pound per MMBTU as the limit to assign in the permit. Based on CEMs data for Emission Unit 2 submitted to EPA in conjunction with the Acid Rain Program, the low NOx burners and other equipment were installed by February 14, 1999. Therefore, the time period February 14 through February 14, 2000 inclusive was selected to determine the rolling twenty four (24) hour average emissions limit for the boiler. In 1999 the maximum rolling twenty four (24) hour average emissions were 0.61 pound per MMBTU heat input. To assure proper operation of the low NOx burner installation, the Department selected the 95th percentile or 0.47 pound per MMBTU as the limit to assign in the permit. These emission limitations have been included in the Regulation No. 30 operating permit.

Since the boilers were installed in 1957 for Unit 1 and 1959 for Unit 2, 40 CFR Part 60 Subpart D is not applicable to either emission unit, since the date of construction for each boiler was prior to August 17, 1971. Delaware Regulation No. 20 is also not applicable to either emission unit, since the date of construction was prior to August 17, 1971.

Regulation No. 25, *Requirements For Preconstruction Review* is not applicable to these boilers since they were installed prior to 1975. There has not been any subsequent construction activity on the boiler units that would trigger Regulation No. 25, *Requirements For Preconstruction Review.*

SCREEN was used to conduct a dispersion analysis of the emissions of regulated pollutants from each boiler. The input parameters and results are summarized in the following tables.

Unit	Boiler size	Stack Height(ft)	Diameter(ft)	Flow (acfm)	Temperature (°F)
1	1,090 MMBTU/hr	500	10.5	452,172	310

Chemical	Hourly Rate (lb/hr)	TLV (8-hr) (mg/m^3)	MDC (mg/m^3)	Distance (m)	TLV:MDC
Particulate Matter	75.5	10	5.39×10^{-3}	1,229	1,855:1
PM-10	17.4	3	1.25×10^{-3}	1,229	2,400:1
Sulfur Dioxide	2548.9	5.2	0.182	1,229	29:1
Nitrogen Dioxide	922.3	5.6	0.066	1,229	85:1
Carbon Monoxide*	209.6	29	1.5×10^{-2}	1,229	1,933:1
VOCs*	1.56	1.0	1.12×10^{-4}	1,229	8,929:1
Methyl hydrazine (VOC)**	7.13×10^{-3}	0.019	5.1×10^{-7}	1,229	37,255:1

* Emission when combusting No. 2 Fuel Oil (Worst Case)

** Based on AP-42 Chapter 1.1, Methyl hydrazine was determined to show the be the worst case TLV:MDC ratio of the VOCs emitted when burning coal

Unit	Boiler size	Stack Height(ft)	Diameter(ft)	Flow (acfm)	Temperature (°F)
2	1,186 MMBTU/hr	500	10.5	452,172	310

Chemical	Hourly Rate (lb/hr)	TLV (8-hr) (mg/m³)	MDC (mg/m³)	Distance (m)	TLV:MDC
Particulate Matter	82.1	10	5.9×10^{-3}	1,229	1,695:1
PM-10	19	3	1.36×10^{-3}	1,229	2,206:1
Sulfur Dioxide	2773.4	5.2	0.198	1,229	26:1
Nitrogen Dioxide	1003.5	5.6	7.2×10^{-2}	1,229	78:1
Carbon Monoxide*	228.1	29	1.6×10^{-2}	1,229	1,813:1
VOC*	1.69	1.0	1.19×10^{-4}	1,229	8,403:1
Methyl hydrazine (VOC)**	7.7×10^{-3}	0.019	5.67×10^{-7}	1,229	33,510:1

* Emission when combusting No. 2 Fuel Oil (Worst Case)

** Based on AP-42 Chapter 1.1, Methyl hydrazine was determined to show the be the worst case TLV:MDC ratio of the VOCs emitted when burning coal

The data in the above tables shows that the sulfur dioxide and nitrogen dioxide emissions do not meet the Department's requirement for the TLV to MDC ratio to be greater than 100:1 for the pollutant. When compared to the National Ambient Air Quality Standards(NAAQS) for 24 hour and annual averages as shown in the tables below, the SO2 and NOx concentrations are less than the NAAQS averages and do not cause an ambient air quality violation.

		1-hr MDC	24-hr MDC	Annual MDC
Factor		**1**	**0.43**	**0.1**
NOx	**Unit 1**	94	40	9
	Unit 2	102	44	10
SOx	**Unit 1**	260	112	26
	Unit 2	283	122	28

Unit 1	24 Hour Average (µg/m³)		Annual Average (µg/m³)	
Pollutant	**NAAQS**	**MDC**	**NAAQS**	**MDC**
Sulfur Dioxide	365	112	80	26
Nitrogen Oxides			100	9

Unit 2	24 Hour Average (µg/m³)		Annual Average (µg/m³)	
Pollutant	**NAAQS**	**MDC**	**NAAQS**	**MDC**
Sulfur Dioxide	365	122	80	28
Nitrogen Oxides			100	10

Emission Unit 3

Indian River Unit 3 is a dry bottom, wall fired, balanced draft type boiler that was placed into service in 1970. The maximum heat input to the boiler is 1,904 MMBTU/hr. The unit is equipped to fire No. 2 fuel oil concurrently with coal from each burner and as a secondary or emergency fuel. The boiler is equipped with an electrostatic precipitator for particulate control and exhausts through a stack 394.5 feet tall. This unit produces steam to power a 165 MW electric generator.

Regulation No. 12, *Control of Nitrogen Oxides Emissions* requires that any source subject to the Regulation shall not emit NOx from affected units without the use of reasonably available control technology (RACT). Section 3.2(b) requires that the Company install low NOx burners with low excess air and overfire air on this emission unit. The emissions limit after installation of the required equipment is determined based on a rolling twenty-four (24) hour averaging period. Based on CEMs data submitted to EPA in conjunction with the Acid Rain Program, the low NOx burners and other equipment were installed by October 15, 1996. Therefore, the time period October 1, 1997 through September 30, 1998 inclusive was selected as representative to determine the rolling twenty-four (24) hour average emissions limit for the boiler. In this period, the maximum rolling twenty-four (24) hour average emissions was 0.67 pound per MMBTU heat input. To assure proper operation of the low NOx burner installation, the Department selected the 95th percentile or 0.57 pound per MMBTU as the limit to assign in the permit. The emission limitation has been included in the Regulation No. 30 operating permit.

Regulation 37 and Regulation 39 are applicable to the boiler. These regulations establish that the nitrogen oxides emissions during the control period (May 1 through September 30 inclusive) must be recorded on an hourly basis and as a cumulative total. The regulations also establish the number of nitrogen oxides emissions allowances that the boiler will receive during the control period. A condition has been include in the permit which requires that hourly mass emissions be determined. The boiler is in compliance with these regulations based on the record keeping and reporting which is currently being performed and submitted to EPA.

The Company has installed over fire air and selective non-catalytic reduction (SNCR) which they intend to use on an as needed basis to comply with the nitrogen oxides allowances allocated under Regulation 37 and Regulation 39. The SNCR control system uses injected urea which reacts with nitrogen oxides in the exhaust gases thus reducing nitrogen oxide emissions. Ammonia (NH_3) slip can occur, therefore a condition restricting NH_3 slip to 15 ppm has been placed in Condition 3 - Table 1(b). In a letter dated May 28, 1999, the Company proposed monitoring surrogate parameters to determine whether excess ammonia slip was occurring. These parameters consisted of items such as comparing the urea flow rate to the optimization baseline testing of the SNCR. Also, because operating conditions change with time, manual testing to confirm ammonia slip must be performed periodically to assure that excess slip is not occurring. Conditions have been included in the permit addressing the operational limitations for the SNCR.

With respect to the NH_3 slip value in the permit, DP&L at its B. L. England Power Plant in New Jersey had installed SNCR and obtained a manufacturer's guarantee that the NH3 slip would not exceed 20 ppm. The State of New Jersey set the NH3 slip limit for the B. L. England Power Plant at 20 ppm. From the experience DP&L had obtained with B. L. England, they asked the manufacturer of the SNCR for a guarantee that NH_3 slip would not exceed 15 ppm at the Indian River Units. The permit requires that the Company test for NH_3 slip by June 1 of each year and optimize the

SNCR to lower NH_3 emissions to 15 ppm or less when the testing demonstrates that NH_3 emissions are greater than 15 ppm.

Condition 3 - Table 1 also includes NH_3 emissions limits for the SNCR installations on Units 3 and 4. Using the NH_3 slip limit of 15 ppm and maximum exhaust flow, the rolling twelve (12) month NH_3 limit for Unit 3 is 115.2 tons and the limit for Unit 4 is 274.7 tons.

The EPA Memorandum, Pollution Control Projects and New Source Review (NSR) Applicability, dated July 1, 1994, allows for exclusion of pollution control projects under certain circumstances. "First, pollution control projects which result in an increase in non-targeted pollutants should be reviewed to determine that the collateral increase has been minimized and will not result in environmental harm. Minimization here does not mean that the permitting agency should conduct a RACT-type review or necessarily prescribe add-on control equipment to treat the collateral increase. Rather, minimization means that, within the physical configuration and operational standards usually associated with such a control device or strategy, the source has taken reasonable measures to keep any collateral increase to a minimum." Although the permitted NH_3 emission levels of 389.9 tons: 115.2 + 274.7, could require review under Regulation No. 25, *Requirements for Preconstruction Review*, the NH_3 emitted is a collateral increase of a non-targeted pollutant. The operational, monitoring and testing requirements which have been placed in the permit will be used to verify that reasonable measures keep the increase of NH_3 emissions to a minimum.

In this case by limiting the NH_3 slip to 15 ppm for each unit the collateral increase was minimized. The modifications qualify as pollution control projects which do not require NSR.

SCREEN was used to conduct a plume dispersion analysis of the PTE emissions of regulated pollutants from this boiler, based on AP-42, Chapter 1.1 or Chapter 1.3. The results are summarized in the following tables. The boiler exhausts through a stack that is 394.5 feet tall, with a 13.5 feet diameter, and a flow of 662,248 acfm at 300 °F.

Chemical	Rate (lb/hr)	TLV (mg/m^3)	MDC (mg/m^3)	Distance (m)	TLV:MDC
Particulate Matter	131.82	10	8.9×10^{-3}	6,851	1,127:1
PM-10	30.32	3	2.0×10^{-3}	6,851	1,500:1
Sulfur Dioxide	4,452.42	5.2	0.3	6,851	17:1
Nitrogen Dioxide	1,611.08	5.6	0.108	6,851	52:1
Carbon Monoxide	366.15	29	2.5×10^{-2}	6,851	1,176:1
VOCs*	2.72	1.0	1.8×10^{-4}	6,851	5,495:1
Methyl hydrazine (VOC)**	1.2×10^{-2}	0.019	8.02×10^{-7}	6,851	23,691:1

* Emission when combusting No. 2 Fuel Oil (Worst Case)
** Based on AP-42 Chapter 1.1, Methyl hydrazine was determined to show the be the worst case TLV:MDC ratio of the VOCs emitted when burning coal

The data in above table shows that the sulfur dioxide and nitrogen dioxide emissions do not meet the Department's requirement of the TLV to MDC ratio being greater than 100:1 for the pollutant. When compared to the National Ambient Air Quality Standards (NAAQS) for 24 hour average and annual average as shown in the table below, the SO_2 and the NOx concentrations are less than the NAAQS averages and do not cause an ambient air quality violation.

	24 hour Average ($\mu g/m^3$)		Annual Average ($\mu g/m^3$)	
Pollutant	**NAAQS**	**MDC**	**NAAQS**	**MDC**
Sulfur Dioxide	365	129	80	30
Nitrogen Dioxide			100	11

Neither 40 CFR Part 60 Subpart D nor Delaware Regulation 20, *New Source Performance Standard*, are applicable to this unit since the boiler was installed and began operation in 1970 which is prior to these regulation's effective date of August 17, 1971.

Regulation No. 25, *Requirements For Preconstruction Review*, applies to major stationary sources on which construction commenced after January 6, 1975. Since the date of installation for this boiler was in 1970, Regulation No. 25 is not applicable to this boiler. As discussed, there has not been any subsequent construction activity on the boiler units that would trigger Regulation No. 25, *Requirements For Preconstruction Review.*

Emission Unit 4

Indian River Unit 4 is a Riley Stoker dry bottom steam production boiler which uses coal as the primary fuel and No. 2 fuel oil as the secondary fuel. The boiler was placed into service in 1980. The maximum heat input rating for this unit is given as nominal 5,091 MMBTU/hr. The unit exhausts through a 410 foot tall stack. The steam from this unit powers a 420 Megawatt (MW) generator.

Regulation No. 12, *Control of Nitrogen Oxides Emissions,* requires that any source subject to the Regulation shall not emit NOx from affected units without the use of reasonably available control technology (RACT). Section 3.2(b) requires that the Company install low NOx burners with low excess air and overfire air on this emission unit. The emissions limit after installation of the required equipment is determined based on a rolling twenty-four (24) hour averaging period. After negotiations between the Department and Indian River Power LLC/NRG Energy Inc., the Company agreed to NOx emissions limits for Emission Unit 4 of 0.47 lb/MMBTU as a rolling 24 hour average and 0.39 lb/MMBTU an annual average. The emission limitation has been included in the Regulation No. 30 operating permit.

Regulation 37 and Regulation 39 are applicable to the boiler. These regulations establish that the nitrogen oxides emissions during the control period (May 1 through September 30 inclusive) must be recorded on an hourly basis and as a cumulative total. The regulations also establish the number of nitrogen oxides emissions allowances that the boiler will receive during the control period. A condition has been included in the permit which requires that hourly mass emissions be determined. The boiler is in compliance with these regulations based on the monitoring, record keeping and reporting which is currently being performed and submitted to EPA.

The Company has installed over fire air and selective non-catalytic reduction (SNCR) which they intend to use on an as needed basis to comply with the nitrogen oxides allowances allocated under Regulation 37 and Regulation 39. The SNCR control system uses injected urea which reacts with nitrogen oxides in the exhaust gases thus reducing nitrogen oxide emissions. Ammonia (NH_3) slip can occur, therefore a condition restricting NH_3 slip to 15 ppm has been placed in Condition 3 - Table 1(c). In a letter dated May 28, 1999, the Company proposed monitoring surrogate parameters to determine whether excess ammonia slip was occurring. These parameters consisted of items such as comparing the urea flow rate to the optimization baseline testing of the SNCR. Also, because operating conditions change with time, manual testing to confirm ammonia slip must be performed periodically to assure that excess slip is not occurring. Conditions have been included in the permit addressing the operation and limitations for the SNCR.

With respect to the NH_3 slip value in the permit, DP&L at its B. L. England Power Plant in New Jersey had installed SNCR and obtained a manufacturer's guarantee that the NH3 slip would not exceed 20 ppm. The State of New Jersey set the NH3 slip limit for the B. L. England Power Plant at 20 ppm. From the experience DP&L had obtained with B. L. England, they asked the manufacturer of the SNCR for a guarantee that NH_3 slip would not exceed 15 ppm at the Indian River Units. The permit requires that the Company test for NH_3 slip by June 1 of each year and optimize the SNCR to lower NH_3 emissions to 15 ppm or less when the testing demonstrates that NH_3 emissions are greater than 15 ppm.

Condition 3 - Table 1 also includes NH_3 emissions limits for the SNCR installations on Units 3 and 4. Using the NH_3 slip limit of 15 ppm and maximum exhaust flow, the rolling twelve (12) month NH_3 limit for Unit 3 is 115.2 tons and the limit for Unit 4 is 274.7 tons.

The EPA Memorandum, Pollution Control Projects and New Source Review (NSR) Applicability, dated July 1, 1994, allows for exclusion of pollution control projects under certain circumstances. "First, pollution control projects which result in an increase in non-targeted pollutants should be reviewed to determine that the collateral increase has been minimized and will not result in environmental harm. Minimization here does not mean that the permitting agency should conduct a RACT-type review or necessarily prescribe add-on control equipment to treat the collateral increase. Rather, minimization means that, within the physical configuration and operational standards usually associated with such a control device or strategy, the source has taken reasonable measures to keep any collateral increase to a minimum." Although the permitted NH_3 emission levels of 389.9 tons: 115.2 + 274.7, could require review under Regulation No. 25, *Requirements for Preconstruction Review*, the NH_3 emitted is a collateral increase of a non-targeted pollutant. The operational, monitoring and testing requirements which have been placed in the permit will be used to verify that reasonable measures keep the increase of NH_3 emissions to a minimum.

In this case by limiting the NH_3 slip to 15 ppm for each unit the collateral increase was minimized. The modifications qualify as pollution control projects which do not require NSR.

The US EPA approved the construction of the 420 MW coal fired steam electric generating station at the Indian River Power Plant in a letter from the regional Administrator of the US EPA to the Director of Environmental Affairs at DP&L, dated October 26, 1976. The *Prevention of Significant Air Quality Deterioration Regulations* 40 CFR 52.21 (PSD) (PSD baseline discussion in next paragraph) were applicable to the unit and required the Company to meet best available control technology (BACT) as defined by 40 CFR Part 60 Subpart D (NSPS), *Standards of Performance for Fossil Fuel Fired Steam Generators for Which Construction Commenced after August 17, 1971*, for the control of emissions of total suspended particulates (TSP) air pollutants. The EPA identified that burning coal with a sulfur content of 0.75% by weight complied with the allowable percent sulfur in fuel as defined by the NSPS was BACT and therefore met the EPA's PSD requirement.

Regulation No. 20 (40 CFR Part 60 Subpart D) is applicable to the boiler. The Regulation (Subpart) establishes limits for particulate emissions, nitrogen oxides emissions, sulfur oxides emissions, and opacity and continuous emissions monitoring systems, records of start-ups, shut-downs and malfunctions, and excess emissions reporting requirements. The limits or requirements are as follows:

a. No owner or operator shall cause to be discharged into the atmosphere any gases which contain particulate matter in excess of 0.10 lb per million Btu heat input.
b. No owner or operator shall cause to be discharged into the atmosphere any gases which contain nitrogen oxides, expressed as NO_2 in excess of 0.70 lb per million Btu heat input.
c. No owner or operator shall cause to be discharged into the atmosphere any gases which contain sulfur dioxide in excess of 1.2 lb per million Btu heat input.
d. No owner or operator shall cause to be discharged into the atmosphere any gases which exhibit greater than 20 percent opacity except for one six-minute period per hour of not more than 27 percent opacity. Compliance is demonstrated based on COMs data.

e. Each owner or operator shall install, calibrate, maintain, and operate continuous monitoring systems for measuring the opacity of emissions, sulfur dioxide emissions, nitrogen oxides emissions, and either oxygen or carbon dioxide.
f. The occurrence and duration of any start-up, shut-down or malfunction of an applicable source; any malfunction of the air pollution control equipment; or any periods during which the continuous monitoring system or monitoring device is inoperative.
g. Excess emission and monitoring system performance reports shall be submitted for each calendar quarter, no later than thirty (30) days following the end of the calendar quarter.

These conditions have been included in the permit

Regulation No. 20 has another applicable visible emissions requirement. The requirement is "No person shall cause the discharge into the atmosphere of particulate matter which is greater than 20 percent opacity, except that a maximum of 40 percent opacity shall be permissible for not more than 2 minutes in any hour." This requirement has also been included in the permit.

Sulfur dioxide (SO_2) emissions from this unit are estimated using a fuel heat content for coal of 13,200 BTU/lb and the emission limit from the NSPS and the Regulation No. 2 permit, of 1.2 lbs/MMBTU. The SO_2 emissions while firing coal calculates to 6,109 lbs/hr and 26,758 tons of SO_2 per rolling 12 month period. Compliance with the emission limit is demonstrated using continuous emission monitors for measurement and recording. Excess emission reports are submitted to the EPA and the Department on a quarterly basis in accordance with 40 CFR Part 60 Subpart D and Regulations No. 20 and No. 25. The applicable requirements for SO_2 emission and operational limitations, monitoring, testing, reporting and record keeping for this emission unit are incorporated into the operating permit in Condition 3-Table 1(c)(3).

The NSPS NOx emission limitation of 0.7 lb/MMBTU of heat input is incorporated into the permit as Condition 3-Table 1(c)(3)(i). The operational limitation includes the requirement to operate the system with a continuous monitoring system. Compliance with the emission limit is demonstrated using continuous emission monitors for measurement and recording. Excess emission reports are submitted to the EPA and the Department on a quarterly basis in accordance with 40 CFR Part 60 Subpart D, Regulation No. 20, Regulation No. 25 and Regulation No. 2 **Permit: APC-82/0149**. The applicable requirements for NOx emission and operational limitations, monitoring, testing, record keeping and reporting for this emission unit are incorporated into the operating permit in Condition 3-Table 1(c)(4).

Regulation 36 and 40 CFR Parts 72 through 78 inclusive are applicable to this boiler. 40 CFR Part 76.7(a)(2) establishes a nitrogen oxides emissions limit of 0.46 pound per MMBTU of heat input on an annual average basis. The more restrictive limit agreed to by the Company of 0.39 pound per MMBTU is less than the regulatory limit and has been placed in the permit. Compliance with this emissions limit will be determined based on CEMs data. These requirements have been incorporated into the Regulation No. 30 operating permit.

SCREEN was used to conduct a dispersion analysis of the PTE emissions of regulated pollutants from this boiler, unless otherwise specified. The results are summarized in the following tables. The boiler exhausts through a stack that is 410 foot tall, 24 foot diameter at a flow of 1,578,323 acfm at 345 °F.

Chemical	Hourly Rate (lb/hr)	TLV (mg/m^3)	MDC (mg/m^3)	Distance (m)	TLV:MDC
Particulate Matter (NSPS)	0.1 lb/MMBTU	10	2.24×10^{-2}	9830	446:1
Sulfur Dioxide (NSPS)	1.2 lb/MMBTU	5.2	0.268	9830	19:1
Nitrogen Dioxide (NSPS)	0.7 lb/MMBTU	5.6	0.157	9830	36:1
Carbon Monoxide	964.2	29	0.042	9830	690:1
VOCs*	7.27	1.0	3.2×10^{-4}	9830	3125:1
Methyl hydrazine (VOC)**	3.28×10^{-2}	0.019	1.43×10^{-6}	9830	13287:1

* Emission when combusting No. 2 Fuel Oil (Worst Case)
** Based on AP-42 Chapter 1.1, Methyl hydrazine was determined to show the be the worst case TLV:MDC ratio of the VOCs emitted when burning coal

The data in above table shows that the sulfur dioxide and nitrogen dioxide emissions do not meet the Department's requirement of the TLV to MDC ratio being greater than 100:1 for the pollutant. When compared to the National Ambient Air Quality Standards (NAAQS) for 24 hour average and annual average as shown in the table below, the SO_2 and the NOx concentrations are less than the NAAQS averages and do not cause an ambient air quality violation.

	24 hour Average ($\mu g/m^3$)		Annual Average ($\mu g/m^3$)	
Pollutant	NAAQS	MDC	NAAQS	MDC
Sulfur Dioxide	365	115	80	27
Nitrogen Dioxide			100	16

Emission Unit 5 - Combustion Gas Turbine, a "Pratt & Whitney FT4 - 9 Turbo Jet Power Pac" rated at 366 MMBTU/hr heat input. Fuel: No. 2 fuel oil (installed in May 1967).

Emission Unit 5 is a remote operated, stationary multi-stage combustion turbine (CT) that was installed at the Facility in 1967. The heat input rating for this unit is 366 MMBTU/hr and it powers a 18.6 MW electricity generator. The CT is fired on No. 2 fuel oil as the primary fuel and uses an air compressor start up engine. The Company requested in the AQM-1001 series application authorization to combust "low sulfur liquid petroleum product" (LSLPP) and on-spec waste oil as secondary fuels. LSLPP is described by the Company as a petroleum distillate having a sulfur content of 0.04% by weight or less. The LSLPP is categorized as No. 2 fuel oil and is regulated through this permit. The conditions for combusting on-spec waste oil have been developed and are included in the Facility wide section of the Regulation No. 30 operating permit.

The application states the unit is operated only during seasonal periods of peak demand and when steam generating units are out of service for maintenance or repair. The application also states that the Company has imposed a capacity factor on the generation potential of the unit to meet the requirements for exemption in accordance with Regulation No. 12.

Regulation No. 4, *Particulate Emissions from Fuel Burning Equipment*, is applicable to this unit. The regulation requires the unit to not emit particulate matter in excess of 0.3 lb/MMBTU heat input, maximum 2-hour average. AP-42 lists the emission factor from Table 3.1-1 for particulate matter emissions from stationary internal combustion sources firing No. 2 fuel oil, identifying all solids and condensables as PM_{10}, as 0.038 lb/MMBTU, which is less than the regulatory limit. Compliance can consistently be demonstrated while No. 2 fuel oil is combusted and shall be based on record keeping. Condition 3-Table 1 (d)(1)(iii) requires the Facility to monitor and record the gallons of fuel combusted in this unit each month.

Regulation No. 8, *Sulfur Dioxide Emissions from Fuel Burning Equipment*, Section 2.2 is applicable. The regulation limits the sulfur content to 0.3% or less by weight. Fuel supplier certification for each No. 2 fuel oil shipment received at the Facility may be used to show compliance with the regulatory standard. The certification requirement includes the following:

A. The name of the oil supplier.
B. The location of the oil when the sample was drawn for analysis to determine the sulfur content of the oil, specifically including whether the oil was sampled as delivered to the facility or whether the sample was drawn from the oil in storage at the oil suppliers or oil refiners facility, or other location.
C. The sulfur content of the oil from which the shipment came (or the shipment itself).
D. The method used to determine the sulfur content.

Fuel oil for this source is drawn from a central tank system which supplies the DP&L Indian River Facility. Fuel suppliers certification is required in Condition 3-Table 1 (a) of the Regulation No. 30 operating permit.

The unit is subject to Regulation No. 12, *Control of Nitrogen Oxide Emissions*. This unit has a rated heat input of 366 MMBTU/hr and has potential NO_X emissions of greater than 100 TPY (located in Sussex County). However, because this unit is permitted as a peaking unit, operation will be limited. The Regulation No. 30 application states on form AQM-1001V that this unit will operate with a "capacity factor" of less than 5% from April 1 thru October 31, meeting the requirements for exemption from Regulation No. 12 under Sections 4.1(e).

Application form AQM-1001X states that a power generation meter will be used to measure the load on each unit and be recorded in a computer database. The calculated load over the appropriate averaging period will be used in determining the capacity factor percentage based on the following calculations:

For the ozone season, defined per Regulation No. 12 Section 4.1(e) capacity factor calculation:

$$CF(\%) = \frac{AvgL}{RF} * 100$$

Where:

CF% = Capacity Factor Percentage

AvgL = Sum of the hourly load on the unit (in MWe-hr), from April 1 through October 31 divided by 5136 hours (hourly length of ozone season)

RF = Rated capacity factor of the unit (18.6 MW)

The unit shall not exceed the operating capacity factor of 5% for the period from April 1 to October 31 as required by Regulation No. 12, Section 4.1 (e). Compliance will be demonstrated based on record keeping and shall be certified in the semi-annual compliance report.

The maximum capacity power during the period from April 1 through October 31 is [(18.6)(5,136)(0.05) = 4,776.5 megawatts (MW)]. The total has been included as an operational limitation in Condition 3 - Table 1(d)(3)(ii)(C) with monitoring and record keeping of the MW produced.

SCREEN was used to conduct a dispersion analysis of the emissions of regulated pollutants from this unit. The rate was determined by multiplying the maximum heat input by the emission factors from AP-42, Chapter 3.1, dated April 2000. It should be noted that the company's revised application, dated June 2002 used emission factors from a previous version of AP-42. The results are summarized in the following table. The unit exhausts through a stack that is 20 feet tall, with a 13.5 feet diameter, and a flow of 541,966 acfm at 792 °F.

Chemical	Rate (lb/hr)	TLV (mg/m^3)	MDC (mg/m^3)	Distance (m)	TLV:MDC
Particulate Matter	4.39	3	1.12×10^{-3}	3598	2,679:1
Sulfur Dioxide	110.90	5.2	2.8×10^{-2}	3598	184:1
Nitrogen Dioxide	322.08	5.6	8.19×10^{-2}	3598	68:1
VOCs	0.15	1.0	3.5×10^{-5}	3598	28,571:1
Carbon Monoxide	1.21	29	3.08×10^{-4}	3598	94,156:1

The data in above table shows that the nitrogen dioxide emissions do not meet the Department's requirement of the TLV to MDC ratio being greater than 100:1 for the pollutant. When compared to the National Ambient Air Quality Standard (NAAQS) for the annual average as shown in the table below, the NOx concentrations are less than the NAAQS averages and do not cause an ambient air quality violation.

	24 hour Average ($\mu g/m^3$)		Annual Average ($\mu g/m^3$)	
Pollutant	**NAAQS**	**MDC**	**NAAQS**	**MDC**
Nitrogen Dioxide			100	12

Regulation No.14, *Visible Emissions*, is applicable to this unit. The regulation requires that the emissions of visible air contaminants shall not be greater than 20% opacity for an aggregate of more than 3-minutes in any 1-hour or more than 15-minutes in any 24-hour period. Since this is a peaking unit with capacity factor limits, compliance shall be demonstrated through proper operation and maintenance of the emission units. Compliance with the standard may be demonstrated by maintaining the following record keeping:

1. Maintain records of all maintenance performed on the Combustion Turbine.
2. Monitor, as needed, in accordance with Section 4.1 of Regulation No. 14; and
3. Maintain all observation records.

Additionally, certification that compliance with Condition 3 - Table 1(p)(3) demonstrates compliance with Condition 3 - Table 1(p)(2(i), the Company shall, at a minimum, conduct a modified Reference Method 9 visible emissions test for each emission unit in accordance with Regulation No. 20, Section 1.5(c) once each calendar year

Regulation No. 25, *Requirements for Preconstruction Review*, is not applicable to this unit since the unit was installed prior to the affective date of Regulation No. 25. Since installation, the unit has not had any modification or reconstruction and the Company has taken operational restrictions on the unit of a 5% annual capacity factor. Therefore, Regulation No. 25 is not applicable to this unit.

The Company is required to comply with Regulation No. 37, *NOx Budget Program.* This is a Facility wide applicable requirement that is State Enforceable Only until the State Implementation Plan (SIP) is approved. These Regulation No. 37 requirements have been met. The Company has certified an authorized account representative for the Company, has submitted documentation to open a compliance account for the NOx Tracking System and has submitted updated monitoring plans with modified heat input calculations for each affected unit. The units were not required to install additional emission monitoring equipment. The Account Certificate of Representation has been evaluated and approved. The NOx Allowance Tracking System (NATS) Administrator was notified by letter and authorized to open a compliance account for the Facility. Beginning in May 1999, compliance with this regulation requires the Company to have in its possession an equal number of NOx allowances as the tons of NOx emitted through the ozone season, at the end of each calender year (December 31). This account must be balanced by December 31 each year or the non-compliance conditions of repayment of three (3) allowances for every one (1) short must be returned to the NATS administrator. The Company submitted the regulation required NOx monitor plan updates which include formula verification that demonstrate the data acquisition system accurately calculates and reports the NOx mass emission rate based on hourly heat input and NOx emission rate. The requirements of Regulation No. 37 have been incorporated into the permit in Condition 3-Table 1(k).

The combustion turbine is subject to Regulation No. 39, *Nitrogen Oxides (NOx) Budget Trading Program.* The permit was issued May 1, 2002. The Regulation No. 39 Permit is included as an enclosure to the Regulation No. 30 permit as required by the NOx Budget Trading Program.

New Source Performance Standard (NSPS) - 40 CFR, Part 60 Subpart GG, *Standards of Performance for Stationary Gas Turbines*, applies to "stationary gas turbines" with a heat input at peak load greater than 10 MMBTU/hr that commenced construction, modification or reconstruction after October 3, 1977. This combustion turbine was constructed in 1967 and has not had any modifications or re-construction, therefore the NSPS is not applicable.

Emission Unit 6 - One (1) Clean Burn CB - 2000 waste oil furnace having a maximum heat input of 0.185 MMBTU/hr and fueled with on-spec used oil at the maintenance building located at the ash disposal site.

This unit is a Clean Burn (CB - 2000) oil burning furnace located in the maintenance building at the ash landfill. It has a maximum heat input of 185,000 BTUs per hour (1.3 gallons per hour). The Regulation No. 2 operating permit, APC 95/0519 was issued for the furnace in June 1995. The following conditions have been included in Condition 3-Table 1(f) of the Regulation No. 30 operating permit.

- The sulfur content of the fuel used in this furnace shall not exceed 0.5 percent by weight.
- The exhaust stack shall be operated with minimum flow restriction, which prohibits the use of the cone shaped vent covers.
- The amount of fuel burned in the furnace shall not exceed 11,388 gallons per year which shall be recorded on a monthly basis.
- Compliance with the conditions and standards shall be demonstrated through record keeping.

Units which combust waste oil must meet requirements for Part 279, *Standards for the Management of Used Oil*, in particular part 279.11. 40 CFR Part 279 and *Delaware Regulations Governing Hazardous Waste* (DRGHW) identify materials which are subject to regulations as used oil and it indicates whether the materials are to be handled as a hazardous waste. Part 279 provides specification of waste oil fuels burned in small furnaces. The fuel proposed for this unit is crankcase oil. Conditions in the Regulation No. 30 operating permit require testing of batches of fuel to demonstrate compliance with the specifications of Part 279. The fuel specification requirements that comport with the federal regulations and DRGHW have been included in the Regulation No. 30 operating permit.

Regulation No. 4, *Particulate Emissions from Fuel Burning Equipment*, is not applicable to this waste oil furnace in accordance with Section 1.2 which states that the regulation does not apply to units with less than 1,000,000 BTU heat input per hour. The condition was in the construction and operation permit issued for the unit in 1995 (APC 95/0519) and has been deleted as an applicable requirement.

Regulation No. 14, Visible Emissions, is applicable to this unit. Particulate emissions from this unit, while operating on used crankcase oil with a sulfur content of 0.5% or less by weight, are less than 0.3 lb/MMBTU. This level of particulate should not have a significant potential to cause an opacity violation. In addition, when properly operated, the furnace does not have a significant potential to cause an opacity violation. Therefore, compliance with the visible emissions standard for this combustion unit is demonstrated based on: record keeping of the fuel type and sulfur content in Condition 3 - Table 1(f)(1)(iii)(C) and operation/maintenance in Condition 3 - Table 1(p)(3) of the Regulation No. 30 operating permit.

Regulation No. 22, *Restriction on Quality of Fuel in Fuel Burning Equipment,* is applicable to this Facility. It states that no person shall burn waste oil in any fuel burning equipment or incinerator without first obtaining a permit. This unit is used in the ash landfill maintenance garage for space heating and is fueled with waste crankcase oil.

SCREEN was used to conduct a dispersion analysis of the emissions of regulated pollutants from this unit. The rate was determined by multiplying the maximum heat input by the emission factors from AP-42, Chapter 1.11, dated October 1996. The results are summarized in the following table. The unit exhausts through a stack that is 31.5 feet tall, with a 0.67 feet diameter, and a flow of 100 acfm at 575°F.

Chemical	Rate (lb/hr)	TLV (mg/m^3)	MDC (mg/m^3)	Distance (m)	TLV:MDC
Particulate Matter	0.068	10	8.2×10^{-3}	44	1,220:1
PM-10	0.059	3	7.1×10^{-3}	44	423:1
Sulfur Dioxide	0.076	5.2	9.2×10^{-3}	44	565:1
Nitrogen Dioxide	0.023	5.6	2.8×10^{-3}	44	2000:1
VOCs	0.0014	1.0	1.9×10^{-4}	44	5,263:1
Carbon Monoxide	0.003	29	3.8×10^{-4}	44	76,316:1

The data in above table shows that the emissions from this unit for these pollutants do meet the Department's requirement of the TLV to MDC ratio being greater than 100:1 for the pollutant.

Emission Unit 7 - Fly Ash Silo; silo includes a pulse jet cleaned baghouse

The fly ash removed from the each electrostatic precipitator and Emission Units 1, 2 and 3 is conveyed to a storage silo and then deposited in the ash landfill or sold by the Company to vendors for off-site utilization. The Company has calculated the inlet loading to the silo using the ash production estimation of 16% of the total coal combusted by the Facility. The maximum loading to the baghouse is calculated to be 527,974 tons per year.

The baghouse associated with the ash silo is a pulse jet cleaned unit containing felted polyester bags. The baghouse has a filter area of 2,800 ft^2 and a flow rate of 6,900 cfm, which gives an air to cloth ratio of 2.46. The generally safe design values for pulse jet cleaning of fly ash of 5 is recommended in *Air Pollution Control Equipment Selection, Design, Operation and Maintenance*. The air to cloth ratio is better than that which is recommended. The emissions were calculated to be 0.001 gr/scf based on an emission factor of 0.00099 lb/ton. The gr/scf value was calculated without the baghouse, therefore the Company shall be in compliance with the Regulation No. 5 standard based on proper operation and maintenance, verified by record keeping.

Fly ash is a cement supplement and the Department believes that the wrong emission factor was used by the Company[1]. The corrected controlled emissions are calculated to be [(527,974 tons/yr)(0.0089 lbs/ton)/(8760 hr/yr)=] 0.5429 pounds per hour and [(527,974 tons/yr)(0.0089 lbs/ton)(1 ton/2000 lbs)=] 2.35 tons per year.

The Company used a control device efficiency of 99.9 percent. A review of the AP-42 emission factors for controlled and uncontrolled emissions indicates a control device efficiency of [(100)(1-0.0089/3.14)=] 99.7 percent. Therefore, the Department accepts a control device efficiency for the filter receivers of 99.7%.

The Title V operating permit limits fly ash transfer rates to the values stated in the AQM series application of 37 tons per hour and 527,974 tons per rolling twelve month period. Using AP-42 emission factors with the 99.7% particulate removal efficiency, controlled particulate emission rate of 0.5429 pounds per hour and 2.35 tons per rolling twelve month period are calculated for the emission units. The rolling twelve month period emission limit has been included in the Title V operating permit.

The calculated average hourly controlled emissions from this unit are 0.5429 pound per hour of particulate matter. The particulate emissions are from a 100 foot, 3.2 foot diameter stack, with a flow of 6,900 acfm at 68°F (ambient temperature). The maximum downwind concentration ($MDC_{1\text{-hr}}$; as obtained in the SCREEN3 analysis, in $\mu g/m^3$) was determined to occur at 98 meters. The recalculated $MDC_{8\text{-hr}}$ concentration [$(MDC_{1\text{-hr}})*(0.7/1000)$] and the $TLV_{8\text{-hr}}$ for the respective air contaminant are used in the calculation of TLV/MDC ratio in order to check the related facility-stack's compliance with the Department's requirement for the TLV/MDC ratio to be greater than or equal to 100. This calculation is shown in the following table:

Air Contaminant	Rate (lb/hr)	TLV (8-hr, mg/m^3)	MDC (8-hr, mg/m^3)	Distance (m)	TLV:MDC
Particulate Matter	0.5429	3	0.00056	144	5,357:1

This emission unit is subject to Regulation No. 5, *Particulate Emissions from Industrial Process Operations*; Section 2.1 restricts the particulate emissions to 0.2 grains per standard cubic foot. The calculated particulate emission rate is 0.001 grains per standard cubic foot, which is less than 0.2 grains per standard cubic foot. This concentration, 0.001 grains per standard cubic foot, is calculated using the following formula:

$$\text{grain/SCF} = \frac{EF*T*7000}{F*60}$$

where:

EF	=	Emission factor (0.0089 lb/ton, includes 99.7% efficiency)
T	=	Amount of fly ash transferred (tons per hour)
F	=	Air flow rate (CFM)
60	=	Conversion factor (min/hr)
7000	=	Conversion factor (grains/lb)

[1]The Company used AP-42 emission factors from Table 11.12-2 for cement unloading to calculate controlled emissions to be [(527,974 tons/yr)(0.00099 lbs/ton)/(8760 hr/yr)=] 0.06 pounds per hour and [(527,974 tons/hr)(0.00099 lbs/ton)(1 ton/2000 lbs)=] 0.26 tons per year.

The demonstration of compliance relies on a maximum ash loading rate of 61 tons per hour, the exhaust flow rate of 6900 cfm and proper operation of the silo and baghouse. The emission limitation of 0.2 gr/scf, operational limitations and related monitoring, testing, record keeping and reporting are incorporated into the Title V operating permit.

Regulation No. 14, *Visible Emissions*, is an applicable requirement for this emission unit. Particulate emissions from this emission unit, when properly operated are 0.001 gr/scf as previously described. This level of particulate emissions is well below that which would cause a violation of the opacity standard. The Company proposed to monitor visible emissions from Emission Unit 76 to demonstrate compliance with the particulate and visible emissions standards. The monitoring has been included in the Title V permit as Condition 3 - Table 1(p)(2)(iii)(B).

Emission Units 8 and 9 - Vacuum Fly Ash Transfer With Filter Receivers from Boilers 1, 2 and 3

Fly ash from boilers 1, 2 and 3 is drawn off with vacuum pumps and collected in filter receivers. The collected fly ash is then pumped to a fly ash silo. The Department believes that the vacuum removal of fly ash from the boilers by a vacuum system is process equipment.

Fly ash is a cement supplement and the Department believes that the wrong emission factor was used by the Company.[2] The corrected controlled emissions are calculated to be [(37 tons/hr)(0.0089 lbs/ton)=] 0.3293 pounds per hour and [(324,120 tons/yr)(0.0089 lbs/ton)(1 ton/2000 lbs)=] 1.44 tons per year.

The Company used a control device efficiency of 99.9 percent. A review of the AP-42 emission factors for controlled and uncontrolled emissions indicates a control device efficiency of [(100)(1-0.0089/3.14)=] 99.7 percent. Therefore, the Department accepts a control device efficiency for the filter receivers of 99.7%.

The Title V operating permit limits fly ash transfer rates to the values stated in the AQM series application of 37 tons per hour and 324,120 tons per rolling twelve month period. Using AP-42 emission factors with the 99.7% particulate removal efficiency, controlled particulate emission rate of 0.3293 pounds per hour and 1.44 tons per rolling twelve month period are calculated for the emission units. The rolling twelve month period emission limit has been included in the Title V operating permit.

The calculated average hourly emissions from this unit are 0.3293 pound per hour of particulate matter. The particulate emissions are from a 65 foot, 0.83 foot diameter stack, with a flow of 1,260 acfm at 68°F (ambient temperature). The maximum downwind concentration ($MDC_{1\text{-hr}}$; as obtained in the SCREEN3 analysis, in $\mu g/m^3$) was determined to occur at 98 meters. The recalculated $MDC_{8\text{-hr}}$ concentration $[(MDC_{1\text{-hr}})*(0.7/1000)]$ and the $TLV_{8\text{-hr}}$ for the respective air contaminant are used in the calculation of TLV/MDC ratio in order to check the related facility-stack's compliance with the Department's requirement for the TLV/MDC ratio to be greater than or equal to 100. This calculation is shown in the following table:

Air Contaminant	Rate (lb/hr)	TLV (8-hr, mg/m³)	MDC (8-hr, mg/m³)	Distance (m)	TLV:MDC
Particulate Matter	0.3293	3	0.0072	98	417:1

[2]The Company used AP-42 emission factors from Table 11.12-2 for cement unloading to calculate controlled emissions to be [(37 tons/hr)(0.00099 lbs/ton)=] 0.037 pounds per hour and [(324,120 tons/hr)(0.00099 lbs/ton)(1 ton/2000 lbs)=] 0.16 tons per year.

This emission unit is subject to Regulation No. 5, *Particulate Emissions from Industrial Process Operations*; Section 2.1 restricts the particulate emissions to 0.2 grains per standard cubic foot. The calculated particulate emission rate is 0.032 grains per standard cubic foot for each vent, which is less than 0.2 grains per standard cubic foot. This concentration, 0.032 grains per standard cubic foot, is calculated using the following formula:

$$\text{grain/SCF} = \frac{EF*T*7000}{F*60}$$

where:

EF	=	Emission factor (0.0089 lb/ton, includes 99.7% efficiency)
T	=	Amount of fly ash transferred (tons per hour)
F	=	Air flow rate (CFM)
60	=	Conversion factor (min/hr)
7000	=	Conversion factor (grains/lb)

The demonstration of compliance relies on a maximum ash loading rate of 37 tons per hour, the exhaust flow rate of 1260 cfm and proper operation of the filter receivers. The emission limitation of 0.2 gr/scf, operational limitations and related monitoring, testing, record keeping and reporting are incorporated into the Title V operating permit.

Regulation No. 14, *Visible Emissions*, is an applicable requirement for this emission unit. Particulate emissions from this emission unit, when properly operated are 0.032 gr/scf as previously described. This level of particulate emissions is well below that which would cause a violation of the opacity standard. The Company proposed to monitor visible emissions from Emission Units 8 and 9 to demonstrate compliance with the particulate and visible emissions standards. The monitoring has been included in the Title V permit as Condition 3 - Table 1(p)(2)(iii)(B).

Emission Unit 10 - Lime Silo and Lime Silo Baghouse

This lime silo can hold approximately 50 tons of lime. The associated passive baghouse has a 4 inch by 4 inch passive vent and contains 48 bags, each 5 inches in diameter and 58 inches long. The AQM-1001 series applications stated that the efficiency of the baghouse is 99.9 percent. The Company stated that they load the silo at a rate of 25 tons/hour. When using an AP-42 emission factor from Chapter 11, Table 11.17-4 with the 99.9% efficiency and the above stated loading rate, the controlled particulate emission rate is calculated to be 0.055 lbs per hour. The Department accepts the control efficiency of 99.9% for the passive baghouse.

The particulate emissions are from the 50 feet high, 4 inch by 4 inch vent, with a flow of 500 cubic feet per minute at 68°F (ambient temperature). The maximum downwind concentration (MDC1hr) as obtained in the Screen 3 analysis is 5.55 ug/m3 at 56 meters. The recalculated $MDC_{8\text{-hr}}$ concentration and the $TLV_{8\text{-hr}}$ for the respective air contaminant are used in the calculating of the TLV/MDC ratio to determine the stack's compliance with the Department's requirement for the TLV/MDC ratio to be greater than or equal to 100. The following table illustrates this stack's compliance with the Department's requirement.

Chemical	Rate (lb/hr)	TLV (mg/m^3)	MDC (mg/m^3)	Distance (m)	TLV:MDC
Particulate Matter	0.055	3	1.9×10^{-3}	79	1,579:1

This emission unit is subject to Regulation No. 5, *Particulate Emissions from Industrial Process Operations*. Section 2.1 restricts the particulate emissions to 0.2 grains per standard cubic foot. The calculated particulate emission rate is 0.128 grains per standard cubic foot, which is less than 0.2 grains per standard cubic foot. This concentration, 0.128 grains per standard cubic foot, is calculated using the following formula:

$$\text{grain/SCF} = \frac{EF*T*E*7000}{F*60}$$

where:

EF	=	Emission factor (2.2 lb/ton)
T	=	Amount of lime transferred to the silo per hour (tons per hour)
E	=	Fractional efficiency of baghouse
F	=	Air flow rate from baghouse (CFM)
60	=	Conversion factor (min/hr)
7000	=	Conversion factor (grains/lb)

The demonstration of compliance relies on a maximum lime loading rate of 25 tons per hour, the exhaust flow rate of 500 cfm and proper operation of the baghouse. The emission limitation of 0.2 gr/scf, operational limitations and related monitoring, testing, record keeping and reporting are incorporated into the Title V operating permit. The calculated particulate matter emission rates from this unit are not significant at 0.055 pound per hour. However, conditions controlling the operation of the emission unit have been included in the Title V operating permit.

Regulation No. 14, *Visible Emissions*, is an applicable requirement for this emission unit. Particulate emissions from this emission unit, when properly operated are 0.196 gr/scf as previously described. This level of particulate emissions is below that which would cause a violation of the opacity standard. Therefore, compliance with Regulation No. 14 for this emission unit is based upon proper operation/maintenance and is incorporated into this units section of Condition 3-Table 1 of the Title V operating permit.

Emission Units 14 and 15 - Gasoline Dispensing Tanks with capacities of 1,000 gallons constructed around 1990 and less than 250 gallons with an unknown construction date.

These tanks are subject to Regulation No. 24 Section 26, Gasoline Dispensing Facility - Stage I Vapor Recovery. Since the tanks have a monthly throughput of less than 10,000 gallons, the Company is required to load the tank by submerged fill, and monitor and keep daily records of the quantity of gasoline delivered to the site. Compliance is demonstrated based upon record keeping. These requirements have been incorporated into the Regulation No. 30 operating permit.

Emission Unit 11 - No. 2 Fuel Oil Storage Tank, 10,000 gallons, installed in 2000.

Since this tank is used to store No. 2 fuel oil, the tank is not required to have a Regulation No. 2 permit in accordance with Regulation No. 2, Appendix A(v), based on true vapor pressure being less than 0.5 psi at 70°F. The vapor pressure of No. 2 fuel oil is 0.007 psi at 70°F.

40 CFR Part 60 Subpart Kb, *Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels)* for Which Construction, Reconstruction, or Modification Commenced after July 23, 1984, applies to storage tanks constructed after July 23, 1984, with a capacity of 40 cubic meters (10,567 gallons) or greater. Subpart Kb is not applicable to either of these emission units based on capacity.

The storage tank is subject to Regulation No. 24 Section 49, *Control of Volatile Organic Compound Emissions from Volatile Organic Storage Vessels*. The storage tanks are restricted to the storage of No. 2 fuel oil with a true vapor pressure of less than 0.5 pounds per square inch. The Company is required to monitor the type of volatile organic liquid that is stored in the emission units. Compliance is demonstrated by keeping records of the type of fuel being stored and the dimensions of each storage vessel with an analysis showing the capacity of each storage vessel. These requirements have been incorporated into the Regulation No. 30 operating permit.

Emission Units 12 and 13 - No. 2 Fuel Oil Storage Tanks #1 and #2 each 250,000 gallons, fixed roof storage tank installed in June 1967.

The No. 2 fuel oil combusted at the Facility is stored in two above ground fixed roof storage tanks each measuring 32 feet high with a diameter of 37 feet. Each has a storage capacity of 250,000 gallons. Since these tanks are used to store No. 2 fuel oil, the tanks were not required to have Regulation No. 2 permits in accordance with Regulation No. 2, Appendix A(v), based on true vapor pressure being less than 0.5 psi at 70°F. The vapor pressure of No. 2 fuel oil is 0.007 psi.

Regulation No. 24, *Control of Volatile Organic Compound Emissions*, Section 31, *Petroleum Liquid Storage in Fixed Roof Tanks*, is applicable to these units. The Company is required to keep records consistent with (e)(2). Section (e)(2) states that records need to be kept if the vapor pressure is greater than 1.0 psia. The vapor pressure for No. 2 fuel oil is less than 1.0 psia and therefore no records are necessary for these units.

These storage tanks were constructed in 1967, and therefore are not subject to the requirements of 40 CFR, Part 60, Subpart K, *Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction Reconstruction, or Modification Commenced After June 11, 1973 and Prior to May 19, 1978.*

Emission Units 16 & 17 - Coal Pile and Coal handling

All coal received at this Facility is transported by rail. Each car is moved to a car dump and emptied by rotation, the rail car is rotated 180 degrees. The coal is transported by belt through a sampling shed where samples are extracted from the conveyor on a continuous basis. The coal proceeds on the conveyor to a transfer/crushing process where coal is either directed to the boiler coal bunkers or the coal storage pile. The coal storage pile is estimated at 20.1 acres of storage area.

Regulation No. 6, *Particulate Emissions from Construction and Materials Handling*, is applicable to this process. Section 6, *Materials Storage*, states that no person shall cause or allow stockpiling or other storage of materials or transport to or from a storage Facility in such a manner as to cause a condition of air pollution. Regulation No. 6 does not impose emission limits, therefore emission limits for this source are not included in the Regulation No. 30 operating permit.

Regulation No. 14, *Visible Emissions*, is an applicable requirement for these emission units. The Company shall monitor visible emissions from Emission Units 109 and 110 to demonstrate compliance with the particulate and visible emissions standards. The monitoring has been included in the Title V permit as Condition 3 - Table 1(p)(3)(iii)(B).

40 CFR Subpart Y, *Standards of Performance for Coal Preparation Plants*, is applicable to this coal handling process since the Facility processes greater than 200 tons of coal per day. The applicable requirement from this regulation are the standards for particulate matter which require that an owner or operator shall not cause to be discharged to the atmosphere from any coal processing and conveying equipment gases which exhibit 20% opacity or greater. The regulation stipulates that coal storage system does not include open storage piles which is the storage method used at Indian River. Transfer and loading system as defined in 40 CFR Subpart Y means any Facility used to transfer and load coal for shipment.

The Company used AP-42 values to estimate the fugitive emissions from the coal handling and coal pile. Emissions from the coal are estimated as 1,714 tons per year of particulate and 856 tons per year of PM_{10}. Test methods and procedures for determining compliance with the opacity aspect of the regulation state that Method 9, *Visible Determination of the Opacity of Emissions from Stationary Sources*, is the appropriate test method to be used unless otherwise specified. Compliance with the VE requirements of 40 CFR 60 Subpart Y shall be demonstrated, at a minimum, through a Reference Method 9 VE being conducted on the coal conveyance equipment at least once per calender year.

Emission Unit 18 - Ash Landfill

Regulation No. 6, *Particulate Emissions from Construction and Materials Handling,* is applicable to this process. Section 6, *Materials Storage*, states that no person shall cause or allow stockpiling or other storage of materials or transport to or from a storage Facility in such a manner as to cause a condition of air pollution. The emissions from the ash landfill were estimated using AP-42, Chapter 13.2.5, *Industrial Wind Erosion*. The calculations estimate emissions of 11.4 tons per year from the ash landfill. Regulation No. 6 does require emission limits, therefore, emission limits for the ash landfill are not included in the Regulation No. 30 operating permit. The pollutant source management practices and requirements have been included as operational limitations in Condition 3-Table 1(p)(3)(iii)(B). Compliance with the operational limitations shall be demonstrated based on record keeping.

Emission Unit 19 - Cold Solvent Parts Cleaner

40 CFR Part 63, Subpart T, *National Emission Standards for Halogenated Solvent Cleaning*, does not apply to the cold solvent degreasers (cleaners). The solvent used in the degreaser is Safety-Kleen Premium Solvent and is not a halogenated solvent.

The AQM-1001 series application was amended to include one (1) cold solvent cleaner. Therefore, the Title V operating permit includes this one (1) cleaner. The Safety-Kleen Premium Solvent has a vapor pressure of 2 mm Hg at 68°F and contains 6.76 pounds of VOC per gallon (100%). Applicable conditions from Regulation No. 24, Section 33(c)(1), *Solvent Metal Cleaning/Standards/Cold Cleaning Facilities*, are included as operational limitations for this cleaner.

This emission unit is subject to Regulation No. 24, *Control of Volatile Organic Compound Emissions*, Sections 5, 6, 8, 33. The Company is in compliance with the applicable requirements by meeting the work-practice standard, the record keeping, reporting, and testing requirements.

Facility Wide

Regulation No. 1, *Definitions and Administrative Principles*, Regulation No. 14, *Visible Emissions*, and Regulation No. 24 Section 8, *Handling, Storage, and Disposal of Volatile Organic Compounds (VOCs)*, and the state-only enforceable Regulation No. 19, *Control of Odorous Air Contaminants*, are applicable for the entire Facility.

In addition to the Facility wide applications, the Company has requested the authorization to burn supplemental fuels which include waste and used oils and petroleum contaminated soils. The Department developed a draft Regulation No. 2 permit and sent it to the Company for review and comment in late 1997. The requirements for burning and handling supplemental fuels were taken from Regulation No. 22, *Restrictions on the Quality of Fuel in Fuel Burning Equipment* and the *Delaware Regulations Governing Hazardous Waste* (DRGHW), including the requirements of Part 279, and **Permit: APC-82/0149** are included in Condition 3 - Table 1.

Applicable Requirements

Federally Enforceable

State of DE Regulation Number	Title	Section/Subpart	Permit Condition
Reg. No. 1	Definitions and Administrative Principles		2.e
Reg. No. 2	Permits	2.1 6.2 7.1 8.1 11.2(j),11.5,12.4	2.d, 2.m,.5.iii 2.b.1 2.n.2 2.k 2.m.5.ii
Reg. No. 3	Ambient Air Quality Standards		2.b.7
Reg. No. 4	Particulate Emissions from Industrial Sources	2.1	3-Table 1
Reg. No. 5	Particulate Emissions from Industrial Sources	1.1 1.5 2.1	2.b.7 3-Table 1 3-Table 1
Reg. No. 6	Particulate Emissions from Construction and Materials Handling		3-Table 1
Reg. No. 12	Control of Nitrogen Oxide Emissions		
Reg. No. 14	Visible Emissions	2.1 4.1	3-Table 1 3-Table 1
Reg. No. 17	Source Monitoring, Record Keeping and Reporting	2.2 7	3.b.1.B 3.c.2.iv
Reg. No. 20	New Source Performance Standards	1 2 9	3-Table 1 3-Table 1 3-Table 1

State of DE Regulation Number	Title	Section/Subpart	Permit Condition
State of DE Reg. No. 24	Control of Volatile Organic Compound Emissions		
	Compliance Certification, Record Keeping and Reporting Requirements for Coating Sources	4	3-Table 1
	General Record Keeping	6	3-Table 1
	Handling, Storage and Disposal of VOCs	8	3-Table 1
	Gasoline Dispensing Facility Stage I Vapor Recovery	26	3-Table 1
	Petroleum Liquid Storage in Fixed Roof Tanks	31	3-Table 1
	Solvent Metal Cleaning	33	3-Table 1
	Control of Volatile Organic Compound Emissions from Volatile Organic Liquid Storage Vessels	49	3-Table 1
Reg. No. 25	Requirements for Preconstruction Review	1 3	3-Table 1 3-Table 1
State of DE Reg. No. 30	Title V State Operating Permit Program		
State of DE Reg. No. 36	Acid Rain Provisions		Title IV Permit
State of DE Reg. No. 37	NOx Budget Program		3-Table 1
State of DE Reg. No. 39	Nitrogen Oxides Budget Trading Program		3-Table 1
40 CFR Part 60	Standards of performance for New Stationary Sources		
	Standards of Performance for Fossil Fuel Fired Steam Generators for which Construction is commenced after August 17, 1971.	D	3-Table 1
	Standards of Performance for Coal Preparation Plants	Y	3-Table 1

State Enforceable

Number	Title	Sect./Subpart	Condition
State of DE Reg. No. 19	Control of Odorous Air Contaminants	2.1	3-Table 1

Destination of Existing Regulation No. 2 Permit Conditions

A listing of the permit condition numbers which were deleted or transferred into this Regulation No. 30 Operating Permit from the Company's six (6) existing Regulation No. 2 Permits, APC-81/0905, APC-81/0906, APC-81/0660 , APC-82/0149, APC-93/461 and APC 95/519 are included in the following table.

Reg. No. 2 Permit	Condition	T/D	Regulation No. 30 Permit Condition
APC-81/0906	1	T	Condition 3 - Table 1(a)
(Emission Unit 1 (IR 1))	2	T	Condition 2(i)
	3	T	Condition 3 - Table 1(a)
	4	T	Condition 3 - Table 1(a)
	5	T	Condition 3-Table 1(a)
	6	T	Condition 3 - Table 1(a) & (d)
	7	T	Condition 3 - Table 1(a)
	8	T	Condition 3 - Table 1(a)
	9	D	Completed
	10	T	Condition 3 - Table 1(a)
	11	T	Condition 3 - Table 1(a)
	12	T	Condition 3 - Table 1(a)
	13	T	Condition 3 - Table 1(a)
	14	T	Condition 3 - Table 1(a)
	15	T	Condition 3 - Table 1(a)
	16	T	Condition 3 - Table 1(p)
	17	T	Condition 3 - Table 1(p)
	18	T	Regulation No. 30 Operating Permit
	19	T	Regulation No. 30 Operating Permit

Reg. No. 2 Permit	Condition	T/D	Regulation No. 30 Permit Condition
APC-81/0906	20	T	Condition 2(k)
(Emission Unit 1 (IR 1))	21	T	Condition 2(b)
APC-81/0905	1	T	Condition 3 - Table 1(a)
(Emission Unit 2 (IR 2))	2	T	Condition 2(i)
	3	T	Condition 3 - Table 1(a)
	4	T	Condition 3 - Table 1(a)
	5	T	Condition 3 - Table 1(a)
	6	T	Condition 3 - Table 1(a) & (d)
	7	T	Condition 3 - Table 1(a)
	8	T	Condition 3 - Table 1(a)
	9	D	Completed
	10	T	Condition 3 - Table 1(a)
	11	T	Condition 3 - Table 1(a)
	12	T	Condition 3 - Table 1(a)
	13	T	Condition 3 - Table 1(a)
	14	T	Condition 3 - Table 1(a)
	15	T	Condition 3 - Table 1(a)
	16	T	Condition 3 - Table 1(p)
	17	T	Condition 3 - Table 1(p)
	18	T	Regulation No. 30 Operating Permit
	19	T	Regulation No. 30 Operating Permit
	20	T	Condition 2(k)
	21	T	Condition 2(b)
APC-81/0660	1	T	Condition 3 - Table 1(b)
(Emission Unit 3 (IR 3))	2	T	Condition 2(i)
	3	T	Condition 3 - Table 1(b)
	4	T	Condition 3 - Table 1(b)
	5	T	Condition 3 - Table 1(b)

Reg. No. 2 Permit	Condition	T/D	Regulation No. 30 Permit Condition
APC-81/0660	6	T	Condition 3 - Table 1(b)
(Emission Unit 3 (IR 3))	7	T	Condition 3 - Table 1(b)
	8	T	Condition 3 - Table 1(b) & (d)
	9	T	Condition 3 - Table 1(b)
	10	T	Condition 3 - Table 1(b)
	11	D	Completed
	12	T	Condition 3 - Table 1(b)
	13	T	Condition 3 - Table 1(b)
	14	T	Condition 3 - Table 1(b)
	15	T	Condition 3 - Table 1(b)
	16	T	Condition 3 - Table 1(b)
	17	T	Condition 3 - Table 1(b)
	18	T	Condition 3 - Table 1(p)
	19	T	Condition 3 - Table 1(p)
	20	T	Condition 3 - Table 1(p)
	21	T	Regulation No. 30 Operating Permit
	22	T	Regulation No. 30 Operating Permit
	23	T	Condition 2(k)
	24	T	Condition 2(b)
APC-82/0149	1	T	Condition 3 - Table 1(c)
(Emission Unit 4 (IR 4))	2	T	Condition 2(i)
	3	T	Condition 3 - Table 1(c)
	4	T	Condition 3 - Table 1(c)
	5	T	Condition 3 - Table 1(c)
	6	T	Condition 3 - Table 1(c)
	7	T	Condition 3 - Table 1(c)
	8	T	Condition 3 - Table 1(d)
	9	T	Condition 3 - Table 1(c)

Reg. No. 2 Permit	Condition	T/D	Regulation No. 30 Permit Condition
APC-82/0149	10	T	Condition 3 - Table 1(c)
(Emission Unit 4 (IR 4))	11	D	Completed
	12	T	Condition 3 - Table 1(c)
	13	T	Condition 3 - Table 1(c)
	14	T	Condition 3 - Table 1(c)
	15	T	Condition 3 - Table 1(c)
	16	T	Condition 3 - Table 1(c)
	17	T	Condition 3 - Table 1(p)
	18	T	Condition 3 - Table 1(p)
	19	T	Condition 3 - Table 1(p)
	20	T	Regulation No. 30 Operating Permit
	21	T	Regulation No. 30 Operating Permit
	22	T	Condition 2(k)
	23	T	Condition 2(b)
APC 93/0461	1	D	The limits are erroneous.
(Emission Unit 5 (IR 10))	2	T	Condition 2(i)
	3	T	Condition 3 - Table 1(e)
	4	T	Condition 3 - Table 1(e)
	5	T	Condition 3 - Table 1(e)
	6	T	Condition 3(c)
	7	T	Condition 3 - Table 1(e)
	8	T	Regulation No. 30 Operating Permit
	9	T	Condition 2(k)
	10	T	Condition 2(b)
APC 95/0519	1	T	Condition 2(d)
(Emission Unit 6(IR 20))	2	T	Regulation No. 30 Operating Permit
	3	T	Condition 2(i)
	4	T	Condition 3 - Table 1(f)

Reg. No. 2 Permit	Condition	T/D	Regulation No. 30 Permit Condition
APC 95/0519	5	T	Condition 3 - Table 1(f)
(Emission Unit 6(IR 20))	6	T	Condition 3(b)
	7	T	Condition 3 - Table 1(p)
	8	T	Condition 3 - Table 1(p)
	9	T	Condition 3 - Table 1(f)
	10	T	Condition 3(c)
	11	T	Regulation No. 30 Operating Permit
	12	T	Condition 2(k)
	13	T	Condition 2(b)

Permit Shield.

The Company has requested a permit shield. The permit shield will cover those applicable requirements addressed in the following table.

Condition 6 - Table 1	
Emission Unit	**Applicable Requirement**
1. Emission Unit 1 & 2	i. Regulation No. 4 Section 2.1 ii. Regulation No. 14 Section 2.1
2. Emission Unit 3	i. Regulation No. 4 Section 2.1
	ii. Regulation No. 8 Section 2.2
	iii. Regulation No. 14 Section 2.1
3. Emission Unit 4	i. Regulation No. 4 Section 2.1
	ii. Regulation No. 8 Section 2.2
	iii. Regulation No. 14 Section 2.1
4. Emission Unit 5	i. Regulation No. 8 Section 2.2
5. Emission Unit 11	i. Regulation No. 24 Section 49

Prepared By:

Permitting Engineer: Thomas I. Lilly
Thomas I. Lilly

Reviewed By:

Scientist: Brian Hurd by NJ
Brian K. Hurd

Program Manager: Nancy E. Terranova
Nancy E. Terranova

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TITLE V PERMIT REVIEW
PERMIT APPLICATION CHECKLIST

SOURCE NAME: Indian River Power, LLC, Indian River Generating Station
STATE: DE
AFS PLANT ID: 10005/000001
SOURCE TYPE: Combustion , electricity generation **PERMIT #: AQM-005/00001**
SIC #: 4911
SOURCE LOCATION (COUNTY): Sussex;

I. Is this a general permit? If yes, which one? ____ (Go to Part III) .... NO
If no, go to Part II.

II. PROGRAM IMPLEMENTATION

Does this permit contain "streamlined limits" (per White Paper #2) .... NO

Does this permit contain requirements/provisions for:

1. Periodic Monitoring .... YES
2. NESHAP/MACT (if so, list subparts) .... NO
3. Case-by -Case MACT .... NO
4. NSPS (if so, list subparts) .... YES
   40 CFR Part 60 Subpart D
   40 CFR Part 60 Subpart Y
5. PSD/NSR .... YES
6. Acid Rain Phase II permit .... YES
7. Potential-to-Emit Limits .... YES
8. Consent Order of Agreement .... NO
9. NOx RACT .... YES
10. VOC RACT .... YES
11. Does permit application contain confidential information? .... NO

III. COMPLIANCE STATUS

Is the source subject to a compliance schedule? .... NO

IV. EPA REVIEW

1. Do you want EPA to review all or part of this permit? .... YES
2. Are there other issues you would like to call to EPA's attention? .... YES
   Please explain.

STATE CONTACT: Thomas Lilly DATE: *Prop. Issue Date*
PHONE: (302) 323-4542

(for EPA use only) date entered ________ *init* ________ *action* ________ *ver 13sep96cklst.app*

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