AIR AND RADIATION ADMINISTRATION
DRAFT TITLE V - PART 70 OPERATING PERMIT

DOCKET # 24-033-2200

COMPANY: KMC Thermo, LLC

LOCATION: 16400 Mattawoman Drive
Brandywine, MD 20613

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MARYLAND DEPARTMENT OF THE ENVIRONMENT
AIR AND RADIATION ADMINISTRATION
AIR QUALITY PERMITS PROGRAM

TITLE V – PART 70 OPERATING PERMIT PROGRAM OVERVIEW

Title V of the Clean Air Act (amended) requires each state to implement a federally enforceable operating permit program for major sources of air pollution. This program, the Part 70 Permit Program, also known as the Title V Permit Program, is designed to provide a comprehensive administrative document (a Part 70 Operating Permit) that identifies all air emissions sources at a given facility and the federal air quality regulations applicable to those sources. The permit establishes the methodology by which the owner/operator will demonstrate compliance, and includes testing, monitoring, record-keeping, and reporting requirements for each emissions source.

A Part 70 Operating Permit does not authorize new construction, and does not add any new emissions limitations, standards, or work practices on an affected facility. There may, however, be additional testing, record keeping, monitoring, and reporting requirements. A Part 70 Operating Permit is a five-year renewable permit. A responsible official for each facility subject to a Part 70 Operating Permit is required to annually certify compliance with each applicable requirement for that facility.

When an application for a Part 70 Operating Permit is received, the Department will complete a technical review of the application and will prepare a draft Part 70 Operating Permit and Fact Sheet. The Fact Sheet will explain the basis and technical analysis used by the Department to develop the federally enforceable permit conditions, including the required testing, monitoring, record keeping, and reporting provisions for each emissions unit at the permitted facility. The Fact Sheet will also include a description of the facility operations and the current compliance status with applicable requirements. If there are any discrepancies between the Part 70 Operating Permit application and the draft permit, the Fact Sheet will contain a discussion of the inconsistencies and the final resolution.

Public Participation Process

The Part 70 Operating Permit Program provides the public, adjacent states, and EPA the opportunity to review and submit comments on draft permits. The public may also request a public hearing on the draft permit.

The purpose of a public hearing is to give interested parties the opportunity to submit comments for the record which are germane to the draft federally enforceable permit conditions. Comments made at the hearing, or in writing to the Department during the comment period, should address errors and deficiencies in the permit such as unidentified emissions units, incorrect or deficient regulation citation, deficient record keeping, monitoring, reporting or testing requirements and unresolved compliance issues. After the public comment period has closed, the Department will review the formal testimony as part of the final review and prepare a Response to Comments document which will be sent to the EPA along with the draft Part 70 Operating Permit and Fact Sheet.

Testimony on state-only requirements will be kept on file at the Department as part of the formal record, however, state-only rules and regulations are not federally enforceable, and therefore are not within the scope of the EPA review. The Department will keep a record of the identity of the commenters, their statements, a summary of the issues raised during the public comment period, and the Response to Comments document for at least five years.

Citizen Petition to EPA to Object to Permit Issuance

Interested parties may petition the EPA to object to the Part 70 Permit if the EPA has not already objected, within 60 days after the 45-day EPA review period has ended. The petition period will be posted on the EPA website. The EPA will only consider objections to the federally enforceable provisions of the draft permit which were raised with reasonable specificity during the public comment period, unless: (1) the petitioner demonstrates that it was impractical to raise the objections within the public comment period, or (2) the grounds for the objection arose after the comment period. If the EPA agrees with the petition, the Department will reopen, revise, or revoke the permit as determined.

Applicant Objection to Permit Issuance and Recourse

If the applicant objects to the federally enforceable permit conditions contained in the issued Part 70 Operating Permit, the applicant has 15 days from receipt of the issued permit to request a contested case hearing. More information on that can be found in 40 CFR, Part 70, and COMAR 26.11.03.11.

MARYLAND DEPARTMENT OF THE ENVIRONMENT
AIR AND RADIATION ADMINISTRATION

NOTICE OF PUBLIC HEARING AND OPPORTUNITY TO SUBMIT WRITTEN COMMENTS

Pursuant to regulations governing the control of air pollution in the State of Maryland, COMAR 26.11.03.07, the Maryland Department of the Environment (the Department) has prepared a draft Title V – Part 70 Operating Permit for KMC Thermo, LLC's Brandywine Power Facility located at 16400 Mattawoman Drive, Brandywine, Maryland 20613. The issuance of this permit will be the subject of a virtual public hearing to be held on July 27, 2023 at 6:30 PM.

The Department has made a tentative determination that the Title V - Part 70 Operating Permit can be issued. A final determination on issuance of the permit will only be made after review of all pertinent information presented at the public hearing or received via written comments during the comment period. Copies of the application, the draft Title V - Part 70 Operating Permit with conditions, the Fact Sheet and other supporting documents are available for public inspection on the Department website:

https://tinyurl.com/DraftTitleV

To attend the virtual public hearing, please register using the following link no later than 5:00 PM on July 26, 2023:

https://tinyurl.com/RegisterKMCThermo

On the day of the public hearing, registered attendees will receive instructions on how to join the virtual hearing using a computer and internet connection or telephone.

Interested persons may make oral comments at the hearing. In lieu of oral statements at the hearing, written comments may be submitted to Ms. Shannon Heafey, Title V Coordinator, by email at shannon.heafey@maryland.gov, or by mail to Ms. Shannon Heafey, Air and Radiation Administration, 1800 Washington Boulevard, Suite 720, Baltimore, Maryland 21230-1720, no later than August 4, 2023.

Comments will be accepted by the Department if they raise issues of law or material fact regarding applicable requirements of Title V of the Clean Air Act, and/or regulations implementing the Title V Program in Maryland found in COMAR.

The Department will provide an interpreter for deaf and hearing-impaired persons provided that a request is made for such service at least ten (10) days prior to the hearing.

Further information may be obtained by emailing or calling Ms. Shannon Heafey, Title V Coordinator, Air Quality Permits Program, Air and Radiation Administration at (410) 537-4433.

Christopher R. Hoagland, Director
Air and Radiation Administration

KMC THERMO, LLC
BRANDYWINE POWER FACILITY
16400 MATTAWOMAN DRIVE, BRANDYWINE, MD 20613-8089
PART 70 OPERATING PERMIT #24-033-2200
DRAFT FACT SHEET

Background

Brandywine Power Facility (Brandywine), formerly known as Panda Brandywine Power Plant, was acquired from Panda Brandywine, LLC on June 1, 2014 by KMC Thermo, LLC. KMC is located in Houston Texas. The Brandywine facility is a nominal 230 megawatts (MW) electric co-generation facility located two miles south of Brandywine in Prince George's County. The facility consists of two combined-cycle units (Emissions Units 1 and 2 [EU-1 and EU-2]). Each unit is comprised of a General Electric (GE) Frame 7EA-DLN1 combustion turbine (CT) rated at 84 MW and an unfired heat recovery steam generator (HRSG). Steam produced by the HRSGs is routed to a common steam turbine (ST) for generation of additional electricity. Brandywine also installed an emergency generator as part of making the facility Black Start capable (Emissions Unit 3[EU-3]), which is a Caterpillar diesel engine Model C175-20 rated at 4000 kW. The EU-3 is fired exclusively on Ultra Low-Sulfur Diesel (ULSD) fuel.

The Maryland Public Service Commission (PSC) issued a Certificate of Public Convenience and Necessity (CPCN) to Panda Brandywine, LLC on September 5, 1994; PSC Case #8488. The facility began commercial operation on October 31, 1996. The facility produces electricity for distribution by the Potomac Electric Power Company (PEPCO). The applicable SIC Code for the facility is 4911 - Electric Services. The project was subject to major New Source Review (NSR), including Prevention of Significant Deterioration (PSD), and Non-Attainment NSR. Approval requirements pertaining to those air quality programs were specified in the CPCN.

Ancillary facilities include a two million gallon Ultra Low-Sulfur Diesel (ULSD) fuel storage tank, a re-circulating cooling water system, and miscellaneous support equipment. The facility utilizes pipeline natural gas (NG) or liquefied natural gas (LNG) as its primary fuel source with ULSD (0.0015 weight percent) fuel serving as a backup fuel. The combustion turbines are equipped with dry low NOx burners for natural gas firing and water injection for controlling NOx emissions when firing ULSD fuel. Brandywine uses natural gas or liquefied natural gas ninety-nine percent of the time and uses ULSD fuel occasionally to ascertain the reliability and availability of the combustion turbines when burning ULSD fuel and during Black Start Events. Brandywine will likely continue this pattern of fuel use.

Brandywine‘s combustion turbines (CTs) are subject to the New Source Performance Standards (NSPS) found in 40 CFR Subpart GG based on the fact that the CTs were constructed after the October 3, 1977 applicability date and have a heat input at peak load equal to or greater than 10.7 gigajoules per hour (10 MMBtu/hr) based on the lower heating value of the fuel fired.

Combustion turbines may also be subject to the combustion turbine MACT established under 40 CFR Part 63 Subpart YYYY if emissions of specified HAPs are exceeded. Subpart YYYY establishes emissions limitations and operating limitations for Hazardous Air Pollutants (HAPs) emissions from stationary combustion turbines located at major sources of HAPs. The Brandywine combustion turbines are not major sources of HAPs emissions since they emit less

than 10 tons per year of a single HAP and less than 25 tons per year of total HAPs. Certified annual HAP emissions are less than one (1) ton as shown in Table 2 below. Consequently, they are not subject to the Subpart YYYY.

As a major source of NOx, Brandywine is also subject to the NOx RACT (Reasonable Available Control Technology) requirements of COMAR 26.11.09.08. This regulation requires that the CTs either meet the emission limitations contained in COMAR 26.11.09.08G or meet applicable PSD limits, whichever is more restrictive. The PSD limits found in CPCN #9341, Condition No. 4, are more restrictive than the COMAR limits and therefore apply.

The major source threshold for triggering Title V permitting requirements in Prince George's County is 25 tons per year for volatile organic compounds (VOC), 25 tons per year for Nitrogen Oxides ($NO_{x)}$, 100 tons per year for any other criteria pollutants, and 10 tons for a single HAP or 25 tons per year for total HAPS. Since the facility-wide actual NO_x emissions are greater than the major source threshold, Brandywine is required to obtain a Title V – Part 70 Operating Permit under COMAR 26.11.03.01. Additionally, it is an affected source subject to Title IV Acid Rain Phase II program requirements.

The Department received Brandywine's Part 70 Operating Permit renewal application on January 29, 2019. An administrative completeness review was conducted and the application was found to be administratively complete. Brandywine was notified of the application completeness decision and thus granting Brandywine an application shield.

Emission Units Identification

Brandywine has identified the following emissions units shown in Table 1 as subject to the Title V Operating Permit program.

Table 1 - Emissions Units

MDE Registration/ No.	Emissions Unit No	Emission Unit Description	Date Installed
033-2200-5-0844	EU-1	One (1) GE Frame 7EA Combustion Turbine rated at 84 MW.	June 1996
033-2200-5-0845	EU-2	One (1) GE Frame 7EA Combustion Turbine rated at 84 MW.	June 1996
033-2200-9-1465	EU-3	One (1) Caterpillar diesel engine Model C175-20 rated at 4000 kW.	May 2015

The following Table 2 summarizes the most recent five years' actual emissions from Brandywine based on its Emission Certification Reports.

Table 2-Actual Emissions

Emission Year	NOx (TPY)	SOx (TPY)	PM_{10} (TPY)	CO (TPY)	VOC (TPY)	HAPS (TPY)
2018	130.03	2.77	9.32	76.57	9.38	0
2017	78.7	1.7	18.9	43.2	6.0	0
2016	136.6	3.2	35.3	80.7	11.2	0
2015	143.61	3.48	33.4	76.38	10.58	0
2014	118	2.6	25.5	58.3	8.1	0

GREENHOUSE GAS (GHG) EMISSIONS

Brandywine emits the following greenhouse gases (GHGs) related to the Clean Air Act requirements: carbon dioxide, methane, and nitrous oxide. These GHGs are generated from the combustion turbines, which are the main sources of combustion related emissions at the plant.

When the Black Start Project was proposed, it was evaluated to determine if it would constitute a major modification of the existing Brandywine facility for construction permitting purposes. The Black Start Project would have been processed as a major modification for PSD and/or NA-NSR if there were significant emission increases associated with the modification. With respect to GHG emissions, the applicable threshold is 75,000 tons per year. The GHG emissions associated with the project was 981 tpy, well below the applicability threshold. While there are no applicable GHG Clean Air Act requirements at this time, the Permittee is still required to annually quantify its facility-wide GHG emissions and report them in accordance with Section 3 of the Part 70 permit.

The following Table 3 summarizes the actual GHG emissions from Brandywine based on its Annual Emission Certification Reports:

Table 3: Greenhouse Gases Emissions Summary

GHG	Factor	2014 tpy CO_2e	2015 tpy CO_2e	2016 tpy CO_2e	2017 tpy CO_2e	2018 tpy CO_2e
Carbon dioxide (CO_2)	1	458,348	600,225.51	635,618	339,231	549502.13
Nitrous Oxide (N_2O)	310	3,665	4,681.37	4,960	2,635	4132.67
Methane (CH_4)	21	827.50	1,082.25	1,147.50	612.50	954.84
Total GHG CO_{2eq}		**462,740.5**	**605,989.13**	**641,725.50**	**342,478.50**	**554,589.65**

Cross-State Air Pollution Rule (CSAPR)

The U.S. Environmental Protection Agency (EPA) issued the Cross-State Air Pollution Rule (CSAPR) in July 2011 to address Clean Air Act requirements concerning interstate transport of air pollution and to replace the previous Clean Air Interstate Rule (CAIR), which the D.C. Circuit remanded to the EPA for replacement. Following the original rulemaking, CSAPR was amended by three further rules known as the Supplemental Rule, the First Revisions Rule, and the Second Revisions Rule. As amended, CSAPR requires 28 states to limit their state-wide emissions of sulfur dioxide (SO_2) and/or nitrogen oxides (NOx) in order to reduce or eliminate the states' contributions to fine particulate matter and/or ground-level ozone pollution in other states. The emissions limitations are defined in terms of maximum statewide "budgets" for emissions of annual SO_2, annual NOx, and/or ozone season NOx by each state's large electricity generating units (EGUs). The emissions budgets are implemented in two phases of generally increasing stringency. As the mechanism for achieving compliance with the emissions limitations, CSAPR establishes federal implementation plans (FIPs) that require large EGUs in each affected state to participate in one or more new emission trading programs that supersede the existing CAIR emissions trading programs. On December 30, 2011, in response to petitions challenging CSAPR, the D.C. Circuit granted a stay of the rule, ordering the EPA to continue administering CAIR on an interim basis. In a subsequent decision, the Court vacated CSAPR but on April 29, 2014, the U.S. Supreme Court reversed that decision and remanded the case to the D.C. Circuit Court for further proceedings. In order to allow CSAPR to replace CAIR in an orderly manner, EPA filed a motion asking the D.C. Circuit to lift the stay and to toll, by three years, all CSAPR compliance deadlines that had not yet passed. On October 23, 2014, the Court granted the EPA's motion.

Consistent with the Court's order, compliance with CSAPR's Phase 1 emissions budgets is now required in 2015 and 2016 and compliance with the rule's Phase 2 emissions budgets and assurance provisions is now required in 2017 and beyond.

This renewal Part 70 permit identifies the applicable regulations of the CSAPR rule as found in 40 CFR Part 97 subparts AAAAA- NOx Annual Trading Program, subparts BBBBB- NOx Ozone Season Trading Program, and subpart CCCCC SO_2 Group 1 - Trading Program.

Recent Amendment to the Facility's Permit Condition

Installation of Black Start Capability

On February 14, 2014, Panda Brandywine LLC filed an application for a CPCN with the PSC to modify Brandywine by adding "Black Start" capability. The application was docketed as PSC Case #9341. The PSC issued a Proposed Order on June 18, 2014 approving the project. The Proposed Order became a Final Order on July 10, 2014. The Final Order incorporated all previous conditions from Case #8488 with additional new conditions, as necessary, to address the Black Start project. As such, the amended CPCN conditions resulting from PSC Case #9341 supersedes the CPCN conditions of PSC Case #8488.

The "Black Start Project" enabled Brandywine to start up a combustion turbine on its own without power from the grid, and to support PJM with regional startup capability during emergency conditions, thus enhancing the power grid system reliability. Specifically, the Black Start Project involved the addition of one 5,646- horsepower (4-MW) Caterpillar C175-20 diesel engine that is used to provide power to start up one of the two existing CTs (the "Black Start unit") during a Black Start event. The diesel engine is fired exclusively on ultra low sulfur diesel (ULSD) and limited to a sulfur content of 0.0015% by weight. As part of the application review, potential emissions from the Black Start CT during a Black Start event were used to determine if the project would trigger the applicability of additional air regulatory programs such as PSD, NA-NSR, NSPS, NESHAP Greenhouse Gas (GHG) emissions. It was determined that neither PSD nor NA-NSR were triggered. However, both NSPS and NESHAP applicability thresholds were triggered. As a consequence, the CPCN was amended to include the applicable NSPS and NESHAP requirements. Additionally, operation of the CT during a Black Start event required that the CT operate at a maximum 10% load level, i.e. a generation rate of approximately 8.4 MW. Because the original CPCN prohibited operating the CT at a level below 51 MW, this specific restriction had to be appropriately amended. The Black Start unit is fully operational.

CPCN Case No. 9341 was amended by the PSC on April 5, 2017 to remove the 51 megawatt (MW) minimum load limit for the combustion turbines (EU-1 and EU-2). The 51 MW minimum load limit was replaced with the requirement (except for start-up and shutdown periods, and during black start events) that "…each combustion turbine unit shall operate only when the unit, for natural gas or LNG firing, is in DLN premix mode, or when firing ULSD fuel oil, water injection is engaged."

COMPLIANCE ASSURANCE MONITORING (CAM) APPLICABILITY

Brandywine is not subject to CAM requirements. CAM is intended to provide a reasonable assurance of compliance with applicable requirements under the Clean Air Act for large emission units that rely on air pollution control (APC) equipment to achieve compliance. The CAM approach establishes monitoring for the purpose of: (1) documenting continued operation of the control measures within ranges of specified indicators of performance (such as emissions, control device parameters, and process parameters) that are designed to provide a reasonable assurance of compliance with applicable requirements; (2) indicating any excursions from these ranges; and (3) responding to the data so that the cause or causes of the excursions are corrected. In order for a unit to be subject to CAM, the unit must be located at a major source, be subject to an emission limitation or standard; use a control device to achieve compliance; have pre-control emissions of at least 100% of the major source amount; and must not otherwise be exempt from CAM. Applicability determinations are made on a pollutant-by-pollutant basis for each emissions unit.

Compliance Assurance Monitoring (CAM) Requirement.
Brandywine Power Facility conducted a Compliance Assurance Monitoring (CAM) analysis for the facility and determined that the facility is not subject to the (CAM) Rule 40 CFR Subpart 64.

Brandywine Power Facility has no emissions sources that utilize any APC devices as defined by 40 CFR §64.1 to achieve compliance when firing natural gas or LNG. The 40 CFR §64.1 definition of a control device specifically excludes passive control measures that act to prevent pollutants from forming such as the use of combustion or other process design features or characteristics. The DLN (Dry Low NOx) combustor technology in use at the Brandywine Power Facility's CTs when firing natural gas or LNG is a passive control measure that acts to prevent NOx from forming.

The Brandywine Power Facility's CTs when firing No. 2 fuel (or ULSD fuel oil) are potentially subject to the CAM rule for NOx since water injection is used to reduce NOx emissions and the 40 CFR §64.1 definition of a control device specifically lists "injection systems (such as water, steam, ammonia, sorbent or limestone injection)" as examples of common control devices. However, the CTs are exempt from the CAM rule requirements during fuel oil firing pursuant to 40 CFR §64.2(b)(1)(vi) since the Part 70 permit specifies a continuous compliance determination method (as defined by 40 CFR §64.1) for the NOx emissions standards. Specifically, the Brandywine Power Facility operates and maintains a NOx/O_2 Continuous Emissions Monitoring system (CEMS) on the exhaust gases from the CTs.

Regional Greenhouse Gas Initiative
The Regional Greenhouse Gas Initiative (RGGI) is a market-based carbon dioxide (CO_2) cap and trade program designed to reduce CO_2 emissions from fossil fuel-fired power plants. Note that this is a **Maryland State-only enforceable program**. Maryland's Healthy Air Act required Maryland to join RGGI by July 2007. Maryland joined RGGI by signing RGGI's multi-state Memorandum of Understanding (MOU) on April 20, 2007. The MOU required Maryland to adopt regulations by December 31, 2008, implementing the RGGI program. The Maryland CO_2 Budget Trading Program, Code of Maryland Regulations (COMAR) 26.09.01 to .03, became effective on July 17, 2008. COMAR 26.09.04 became effective as an emergency action on April 4, 2008 and as a permanent action on August 25, 2008.

The regulation requires the following:

(a) Implement a cap and trade program for CO_2 emissions from fossil fuel-fired electric generating units located in Maryland having a capacity of at least 25 megawatts;
(b) Distribute CO_2 allowances to stakeholders through auction, sale and/or allocation;
(c) Require each affected source to have a CO_2 budget account representative and a compliance account;
(d) Require each budget unit to hold in its source's compliance account at the end of each 3-year control period one allowance for each ton of CO_2 emissions emitted in that period;
(e) Require sources to monitor emissions and submit quarterly and annual emission reports;

(f) Establish set-aside accounts for voluntary renewable purchase, limited industrial generator exemptions, and long-term contract generators;
(g) Establish a consumer benefit or strategic energy purpose fund to support energy efficiency, directly mitigate electricity ratepayer impacts, promote renewable or non-carbon emitting energy technologies, stimulate or reward investment in the development of innovative carbon emissions abatement technologies with significant carbon reduction potential, and fund administration of the program; and
(h) Establish procedures to evaluate and award allowances to persons who undertake offset projects that will reduce CO_2 emissions.
(i) Require affected sources to submit an application for a CO_2 Budget Permit.

A renewed CO_2 Budget Permit is being issued in conjunction with the Part 70 permit as Attachment 1.

MERCURY AND AIR TOXICS (MATS) RULE

The US EPA finalized on February 16, 2012, the National Emissions Standards for Hazardous Air Pollutants from coal and oil-fired Electric Utility Steam Generating Units (EGUs) codified under 40 CFR Part 63, Subpart UUUUU, also known as the Mercury and Air Toxics (MATS) rule. The MATS rule established national emission limitations and work practices for certain hazardous air pollutants emitted from coal and oil-fired steam generating units as well as requirements to demonstrate initial and continuous compliance with the emission limitations. Existing units are required to comply with the rule requirements by April 16, 2015 while new or reconstructed units were required to comply by April 16, 2012 or upon start-up.

Brandywine is not subject to this subpart. Although Brandywine Power Facility uses ULSD fuel as backup fuel, it does not meet the definition of oil-fired electric utility steam generating unit. Oil-fired electric utility steam generating unit means an electric utility steam generating unit meeting the definition of ‘‘fossil fuel-fired’’ that is not a coal-fired electric utility steam generating unit and that burns oil for more than 10.0 percent of the average annual heat input during any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year.

Overview of the Part 70 Permit

Section I of the Part 70 Permit contains a brief description of the facility and an inventory list of the emissions units for which applicable requirements are identified in Section IV of the permit.

Section II of the Part 70 Permit contains the general requirements that relate to administrative permit actions. This section includes the procedures for renewing, amending, reopening, and transferring permits, the relationship to permits to construct and approvals, and the general duty to provide information and to comply with all applicable requirements.

Section III of the Part 70 Permit contains the general requirements for testing, record keeping and reporting; and requirements that affect the facility as a whole, such as open burning, air pollution episodes, particulate matter from construction and demolition activities, asbestos provisions, ozone depleting substance provisions, general conformity, and acid rain permit. This section includes the requirement to report excess emissions and deviations, to submit an annual emissions certification report and an annual compliance certification report, and results of sampling and testing.

Section IV of the Part 70 Permit identifies the emissions standards, emissions limitations, operational limitations, and work practices applicable to each emissions unit located at the facility. For each standard, limitation, and work practice, the permit identifies the basis upon which the Permittee will demonstrate compliance. The basis will include testing, monitoring, record keeping, and reporting requirements. The demonstration may include one or more of these methods.

Section V of the Part 70 Permit contains a list of insignificant activities. These activities emit very small quantities of regulated air pollutants and do not require a permit to construct or registration with the Department. For insignificant activities that are subject to a requirement under the Clean Air Act, the requirement is listed under the activity.

Section VI of the Part 70 Permit contains State-only enforceable requirements. Section VI identifies requirements that are not based on the Clean Air Act, but solely on Maryland air pollution regulations. These requirements generally relate to the prevention of nuisances and implementation of Maryland's Air Toxics Program.

Regulatory Review/Technical Review/Compliance Methodology

Emissions Unit EU-1 and EU-2

EU-1 and EU-2: Each of these units operates on the average a total of 185 days or 4440 hours per year during, which the units combust natural gas or liquefied natural gas. The average annual hourly operation of both CTs on fuel oil is less than 31 hours per year.

Applicable Requirements

Control of Visible Emissions

A. **COMAR 26.11.09.05A (2*)* -** Visible Emissions.
"In Areas III and IV, a person may not cause or permit the discharge of emissions from any fuel burning equipment, other than water in an uncombined form, which is visible to human observers."

Exceptions. "Section A (1) and (2) do not apply to emissions during load changing, soot blowing, startup, or occasional cleaning of control equipment if:

(a) The visible emissions are not greater than 40 percent opacity; and
(b) The visible emissions do not occur for more than 6 consecutive minutes in any sixty minute period."

Compliance Demonstration
The Permittee will comply with the visible emissions requirements by properly operating and maintaining the combustion turbines guided by the Permittee's operations manual and preventive maintenance plan designed for the turbines. The Permittee shall verify no visible emissions when burning ULSD fuel oil. An observer shall perform at least one EPA Reference Method 9 observation of stack emissions for a 6-minute period for each 168 hours that each of the combustion turbines burns fuel oil. If a turbine operates on fuel oil for less than 168 hours in a year, the observation requirement is waived for that calendar year.

In the event of observation of visible emissions, the Permittee shall perform the following:

(a) Inspect the combustion turbine operations;
(b) Perform all necessary adjustments and/or repairs to the turbines within 48 hours so that visible emissions are eliminated;
(c) Document in writing the results of the inspections, adjustments and/or repairs to the turbines; and
(d) If the required adjustments and/or repairs have not eliminated the visible emissions within the stipulated 48 hours, perform a Method 9 observation once daily for 18 minutes until corrective action has eliminated the visible emissions.

The Permittee shall maintain the results of visible emissions observations and maintenance performed which relates to combustion performance for at least 5 years and made available to the Department upon request. The Permittee shall also report incidents of visible emissions in accordance with Condition 4 of Section III "Report of Excess Emissions and Deviation [**References: COMAR 26.11.03.06C**].

Rationale/Discussion:
Visible emissions when burning natural gas will only occur during periods of improper combustion, which would not be allowed to continue due to safety considerations. Visible emissions from the combustion of fuel oil are possible but unlikely with normal operation and maintenance.

The facility periodically burns fuel oil in the CTs to ascertain the reliability and availability of the combustion turbines when burning fuel oil in case there is natural gas curtailment. These curtailment periods are not preplanned and may occur for short periods and at times when visible emission observations are not feasible due to constraints of time of day or weather conditions. The requirement to perform an observation once every 168 hours (one week) of fuel oil combustion per combustion turbine unit will provide sufficient time for the Permittee to have the observation completed. Whenever visible emissions are observed, the Permittee is required

to report the incident in accordance with Permit Condition 4 of Section III "Report of Excess Emissions and Deviation". Condition 4 requires a semi-annual monitoring report of deviations (excess emissions).

Compliance Status
The Department conducted a full compliance inspection of the facility on April 08, 2019. Inspection of the records indicated that the latest Method 9 Observation was performed on August 18, 2018 and no visible emissions were observed during the test. Visible emissions observations conducted in prior years also showed no visible emissions.

B. Control of Sulfur Dioxide and Sulfuric Acid Mist Emissions

B1. **CPCN No. 9341**, **Air Quality Section, Conditions No. 8,** which limits the sulfur content in ULSD fuel oil to 0.0015 wt %.

B2. **CPCN No. 9341**, **Air Quality Section, Conditions No. 5,** which limits sulfur dioxide emissions from each combustion turbine to the limits shown below, as hourly emissions expressed in pounds per hour, except during periods of start-up, shutdown, malfunction, and Black Start Events:

	Natural Gas	LNG	ULSD fuel oil
Sulfur Oxides (as SO_2)	29	29	54

B3. **CPCN Case No. 9341, Air Quality Section, Condition No. 5,** which limits sulfuric acid mist from each combustion turbine to the limits shown below, as hourly emissions expressed in pounds per hour, except during periods of start-up, shut-down, malfunction and Black Start Events:

	Natural Gas	LNG	ULSD Fuel Oil
Sulfuric Acid Mist	3	3	6

NSPS Limitation

B4. **40 CFR 60.333 - NSPS Subpart GG** which limits sulfur content of any fuel burned in a gas turbine to 0.8 wt %.

B5. **Phase II Acid Rain Requirement**

The Permittee shall comply with the provisions and all applicable requirements of the Phase II Acid Rain program. See Appendix A in the permit for the renewal Acid Rain Permit.

B6. **Cross-State Air Pollution Rule**
TR SO_2 Group 1 Trading Program 40 CFR Part 97 Subpart CCCCC
The Permittee shall comply with the provisions and requirements of §97.601 through §97.635

Note: §97.606(c) SO_2 emissions requirements. For TR SO_2 Group 1 emissions limitation: As of the allowance transfer deadline for a control period in a given year, the owners and operators of each TR SO2 Group 1 source and each TR SO_2 Group 1 unit at the source shall hold, in the source's compliance account, TR SO_2 Group 1 allowances available for deduction for such control period under §97.624(a) in an amount not less than the tons of total SO_2 emissions for such control period from all TR SO_2 Group 1 units at the source.
Allowance transfer deadline means, for a control period in a given year, midnight of March 1 (if it is a business day), or midnight of the first business day thereafter (if March 1 is not a business day), immediately after such control period and is the deadline by which a TR SO_2 Group 1 allowance transfer must be submitted for recordation in a TR SO_2 Group 1 source's compliance account in order to be available for use in complying with the source's TR SO_2 Group 1 emissions limitation for such control period in accordance with §§97.606 and 97.624.

Compliance demonstrations for SO_2 and Sulfuric Acid Mist Emissions

B1, B2 and B3 - CPCN Compliance Demonstration

Testing and Monitoring for CPCN
The Permittee shall perform QA/QC procedures for the SO_2 monitoring system in accordance with 40 CFR Part 75 Appendix D. [**Reference: CPCN No. 9341, Condition #s 5 and 8, NSPS 40 CFR 60.334(h), and Acid Rain 40 CFR Part 75.21].** The Permittee shall comply with the CPCN requirements by performing sampling and analysis of the "as fired" ULSD fuel oil to determine the percentage of sulfur by weight in the ULSD fuel oil as prescribed in 40 CFR 75 Appendix D. [**Reference: CPCN No. 9341, Condition #s 5 and 8, Air Quality Section**].

Recordkeeping requirement for CPCN
The Permittee shall maintain all records including the fuel analyses for 2 years and shall make the record available to the Department upon request [**References: CPCN No 9341 Condition**

14]. **Note:** Part 70 permits require records to be maintained for 5 years rather than 2 years as referenced in the CPCN condition.

Reporting requirement for CPCN
The Permittee shall submit quarterly reports, in the format approved by the Department, on the sulfur content of the ULSD fuel oil storage tank after ULSD fuel oil delivery; consistent with methods specified in 40 CFR 75, Appendix D, Section 2.2. The quarterly report shall be submitted within 45 days of the end of each calendar quarter **[Reference: CPCN No. 9341, Condition No. 14, Air Quality Section**]. **Note:** For any calendar quarter during which no delivery of ULSD fuel oil is received, the quarterly report shall state that no ULSD fuel oil was received during the quarter.

Rationale/Discussion:
The CPCN pounds per hour limits were established based on the sulfur in fuel limitation and the design of the turbines. Brandywine uses the alternative 40 CFR Part 75 Appendix D procedures for monitoring sulfur dioxide. Heat input is monitored using 40 CFR Part 75 Appendix F. Fuel flow rates for both natural gas and ULSD fuel oil are measured using fuel flow meters meeting the accuracy requirements of 40 CFR 75 Appendix D. The performance tests performed in 1996 reported sulfur oxide emissions level well below the permitted limits for both natural gas and fuel oil. For Unit 1 when burning natural gas, the average of three test runs for sulfur oxide was 20 lbs/hr and sulfuric acid mist was 1.9 lbs/hr. When burning No. 2 fuel oil, the average for sulfur oxide was 32 lbs/hr. and the average for sulfuric acid mist was 4.3 lbs/hr. For Unit 2 when burning natural gas, the average of three test runs for sulfur oxide was 20 lbs/hr and sulfuric acid mist was 2.7 lbs/hr. When burning No. 2 fuel oil, the average for sulfur oxide was 33 lbs/hr. and the average for sulfuric acid mist was 3.3 lbs/hr. Compliance with the sulfur in fuel limit will ensure compliance with the pounds per hour limits.

Compliance Status
The Permittee complies with the requirements of 40 CFR Part 75 Appendix D with respect to sampling and analysis of the "as fired" fuel oil to determine the percentage of sulfur by weight in the fuel oil. The Permittee conducts analyses of the sulfur content of the distillate fuel oil combusted in the turbines and performs QA/QC on the fuel flow meters. There have been no recent fuel deliveries, but a fuel analysis conducted on a shipment by Washington Gas on 1/12/2018 indicated a Sulfur content of 7.3 ppm (0.00073 percent by weight). The Permittee also complies with the recording and reporting requirements. The Permittee has never violated the SO_2 limitations.

B 4. NSPS - Subpart GG compliance demonstration

Monitoring requirement for NSPS Subpart GG

Natural gas

Notwithstanding the provisions of paragraph (h) (1) of this section, the Permittee may elect not to monitor the total sulfur content of the gaseous fuel combusted in the turbine, if the gaseous fuel is demonstrated to meet the definition of natural gas in §60.331(u), regardless of whether an existing custom schedule approved by the administrator for subpart GG requires such monitoring. The owner or operator shall use one of the following sources of information to make the required demonstration

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

b. Representative fuel sampling data, which show that the sulfur content of the gaseous fuel does not exceed 20.0 grains/100 scf. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of appendix D to Part 75 is required. **[Reference: 40 CFR 60.334(h)(3)(i) and (ii)].**

ULSD Fuel Oil

The frequency of determining the sulfur (and nitrogen) content of the ULSD fuel oil is as follows:
Use one of the total sampling options and associated sampling frequency described in sections 2.2.3, 2.2.4.1, 2.2.4.2, and 2.2.2.4.3 of appendix D to part 75 of this chapter (i.e., flow proportional sampling, daily sampling, sampling from the unit's storage tank after each addition of the fuel to the tank, or sampling each delivery prior to combining it with ULSD fuel oil already in the intended storage tank **[Reference: 40 CFR 60.334(i)(1)]**.

Recordkeeping requirement for NSPS Subpart GG
"An owner or operator who is subject to the provisions of this part shall maintain a record of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by this part recorded in a permanent form suitable for inspection." [**Reference: 40 CFR 60.7(f)].**

Reporting Requirement for NSPS Subpart GG
For each affected unit required to continuously monitor parameters or emissions or to periodically determine the sulfur content or fuel nitrogen content under this subpart, the owner or operator shall submit reports of excess emissions and monitor downtime, in accordance with section 60.7(c). Excess emissions shall be reported for all periods of unit operation, including startup, shutdown and malfunction. For the purpose of reports required under section 60.7(c), periods of excess emissions and monitor downtime that shall be reported are defined as follows:

The Permittee who is required to monitor the sulfur content of the fuel under paragraph (h) of this section:

(i) For samples of gaseous fuel and for ULSD fuel oil samples obtained using daily sampling, flow proportional sampling or sampling from unit's storage tank, an excess emission occurs when each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the gas turbines exceeds 0.8 weight percent and ending on a date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit.

(ii) If the option to sample each delivery of fuel oil has been selected, the Permittee, owner or operator shall immediately switch to one of the other oil sampling options (i.e., daily sampling, flow proportional sampling, or sampling from the unit's storage tank from) if the sulfur content of a delivery exceeds 0.8 weight percent. The Permittee shall continue to use one of the other sampling options until all of the oil from the delivery has been combusted, and shall evaluate excess emissions according to paragraph (j)(2)(i) of this section. When all of the fuel from the delivery has been burned, the owner or operator may resume using the as delivered sampling option.

(iii) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor's downtime also begins on the date and hour of a required sample, if invalid results are obtained. The period of monitor downtime shall include only unit operating hours, and ends on the date and hour of the next valid sample. [**Reference: 40 CFR 60.334(j) (2) (i) (ii) (iii)**].

All reports required under §60.7(c) shall be postmarked by the 30th day following the end of each calendar quarter [**Reference: 40 CFR 60.334(j) (5)**].

Compliance Status
The gaseous fuel meets the definition of natural gas. Analysis conducted by Washington Gas showed that the total sulfur content to be 1.53 ppm or 0.096 gr/scf. Each fuel-oil delivery is analyzed and kept on site. The fuel-oil is typically in the range of 0.039 percent by weight %. The required use of ULSD fuel will further restrict the sulfur in fuel content to a maximum of 0.0015 percent by weight. Consequently, the CPCN limit is significantly more stringent than the current NSPS limit. Furthermore, there has never been a violation of the NSPS sulfur in fuel limit.

Phase II SO_2 Acid Rain Requirements

B5. A renewal Phase II Acid Rain Permit is being reissued in conjunction with the issuance of this Part 70 Permit. The Phase II Acid Rain Permit requires the Permittee to limit the actual emissions of sulfur dioxide to the number of allowances that the Permittee holds in its account with the Environmental Protection Agency's Clean Air Markets Program at the end of each calendar year. An allowance is one ton of sulfur dioxide emissions. The

Permittee is required to purchase allowances to cover all the actual emissions in each calendar year.

The Permittee shall comply with the provisions and all applicable requirements of the Phase II Acid Rain Permit program. See Appendix A for the Phase II Acid Rain Permit.

Information about emissions and compliance status can be viewed on EPA's Clean Markets Website, http://www.epa.gov/airmarkets

Cross-State Air Pollution Rule

B6. The Permittee shall comply with the monitoring requirements found in §97.606, §97.630, §97.631, §97.632, and §97.633, the recordkeeping requirements found in §97.606, §97.630, and §97.634, and the reporting requirements; and the reporting requirements found in §97.606, §97.630, §97.633 and §97.634.

C. Control of Nitrogen Oxides Emissions

C1. **CPCN No. 9341, Air Quality Section, Condition No. 4**, which limits nitrogen oxides (NOx) emissions for each turbine, except during periods of start-up, shut-down, and malfunction, and Black Start Events when burning natural gas, ULSD fuel oil and LNG as follows:

(a) Natural gas: the outlet concentration of NOx shall not exceed 9 parts per million by volume on a dry basis (ppmvd) at 15 percent excess oxygen on an hourly basis.
(b) LNG: the outlet concentration of NOx shall not exceed 10 ppmvd at 15 percent excess oxygen on an hourly basis.
(c) ULSD fuel oil: the outlet concentration of NOx shall not exceed 54 ppmvd at 15 percent excess oxygen on an hourly basis.

C2. **CPCN Case No. 9341, Air Quality Section, Condition No. 5**
Each combustion turbine, except during start-up period, shutdown, malfunction, and Black Start Events shall be limited to no more than the following hourly emissions expressed in units of pounds per hour:

	Natural Gas	LNG	ULSD fuel oil
Nitrogen Oxides (as NO_2)	35	39	239

C3. **CPCN Case No. 9341, Air Quality Section, Condition No. 6**
Annual facility-wide NOx emissions shall be limited to no more than 437 tons per year (as NO_2), excluding emissions during periods of start-up, shutdown, malfunction; or PJM system emergency or Black Start Events as defined in Condition 11of the CPCN; Under no circumstance shall facility-wide NOx emissions exceed 518 tons per year.

NSPS LIMITATION

C4. **40 CFR 60.332 - NSPS Subpart GG**, which limits NOx emissions for each turbine when burning natural gas, ULSD fuel oil and LNG as derived by the following formula:

STD = 0.0075 (14.4/Y) + F
Where:
STD = Allowable NOx emissions (percent by volume at 15 percent oxygen and on dry basis).
Y = Manufacturer's rated heat rate at manufacturer's rated load (kilojoules per watt hour (kj/wh) or, actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kj/wh.
F = NOx emissions allowance for fuel bound nitrogen as defined in paragraph (a) (4) of 40 CFR 60.332.

The value of Y (for the combustion turbines) used with the above formula is 11.160 kj/kwh while the weight percent of the fuel bound nitrogen used in deriving the value of F for: natural gas is 0.21 percent; LNG is 0.21 percent; and ULSD fuel oil is 0.021 percent.

NSPS NOx emissions limit for each turbine using the respective fuels is as follows:

(a) Nat gas: the outlet concentration of NOx shall not exceed 144 parts per million by volume on a dry basis (ppmvd) at 15 percent excess oxygen on an hourly basis.
(b) LNG: the outlet concentration of NOx shall not exceed 144 parts per million by volume on a dry basis (ppmvd) at 15 percent excess oxygen on an hourly basis.
(c) ULSD fuel oil: the outlet concentration of NOx shall not exceed 101 parts per million by volume on a dry basis (ppmvd) at 15 percent excess oxygen on an hourly basis.

C5. **NOx RACT Requirement**

COMAR 26.11.09.08G (2) applies to combustion turbines with a capacity factor greater than 15 percent and requires the Permittee to meet an hourly average NOx emission rate of not more than 42 ppm when burning gas or 65 ppm when burning fuel oil (dry volume at 15 percent oxygen) or meet applicable Prevention of Significant Deterioration limits, whichever is more restrictive.

C6. **Cross-State Air Pollution Rule**

TR NOx Annual Trading Program 40 CFR Part 97 Subpart AAAAA
The Permittee shall comply with the provisions and requirements of §97.401 through §97.435

TR NOx Ozone Season Trading Program 40 CFR Part 97 Subpart BBBBB
The Permittee shall comply with the provisions and requirements of §97.501 through §97.535

Note: §97.406(c) NOx emissions requirements. For TR NOx Annual emissions limitation: As of the allowance transfer deadline for a control period in a given year, the owners and operators of each TR NOx Annual source and each TR NOx Annual unit at the source shall hold, in the source's compliance account, TR NOx Annual allowances available for deduction for such control period under §97.424(a) in an amount not less than the tons of total NOx emissions for such control period from all TR NOx Annual units at the source.

Allowance transfer deadline means, for a control period in a given year, midnight of March 1 (if it is a business day), or midnight of the first business day thereafter (if March 1 is not a business day), immediately after such control period and is the deadline by which a TR NOx Annual allowance transfer must be submitted for recordation in a TR NOx Annual source's compliance account in order to be available for use in complying with the source's TR NOx Annual emissions limitation for such control period in accordance with §§97.406 and 97.424.

§97.506(c) NOx emissions requirements. For TR NOx Ozone Season emissions limitation: As of the allowance transfer deadline for a control period in a given year, the owners and operators of each TR NOx Ozone Season source and each TR NOx Ozone Season unit at the source shall hold, in the source's compliance account, TR NOx Ozone Season allowances available for deduction for such control period under §97.524(a) in an amount not less than the tons of total NOx emissions for such control period from all TR NOx Ozone Season units at the source.

Allowance transfer deadline means, for a control period in a given year, midnight of December 1 (if it is a business day), or midnight of the first business day thereafter (if December 1 is not a business day), immediately after such control period and is the deadline by which a TR NOx Ozone Season allowance transfer must be submitted for recordation in a TR NOx Ozone Season source's compliance account in order to be available for use in complying with the source's TR NOx Ozone Season emissions limitation for such control period in accordance with §§97.506 and 97.524.

C1., C2., and C3. - PSD (CPCN) Compliance Demonstration

Testing and Monitoring for PSD (CPCN)
The Permittee shall operate a CEMS for NOx and oxygen (O_2) in accordance with COMAR 26.11.01.10 and 11. The Permittee shall develop, implement, and maintain for all CEMS a Quality Assurance (QA) Plan which satisfactorily documents operations pursuant to 40 CFR 60, Appendix F. **[Reference: CPCN No. 9341, Condition No. 13, Air Quality Section]**. Note that because Brandywine is an Acid Rain Source, the QA/QC procedures for the NOx CEMS are conducted in accordance with 40 CFR Part 75, Appendix D rather than 40 CFR Part 60 Appendix F.

Recordkeeping for PSD (CPCN)
The Permittee shall maintain all records necessary to comply with the NOx data reporting requirements of CPCN No. 9341, Condition 14. **[Reference: COMAR 26.11.03.06C]**

Reporting for PSD (CPCN)
The Permittee shall submit a quarterly summary report to the Department not later than 30 days following each calendar quarter. For details of the reporting requirement, see the reporting requirements for Operational Limitation-Condition G.

Compliance Status
The performance tests performed in 1996 reported NOx emissions levels, which are well below the permitted limits for both natural gas and fuel oil. For natural gas, the average of three test runs was 29 lbs/hr for Unit 1 and 32 lbs/hr for Unit 2. For No. 2 fuel oil, the average of three test runs was 176 lbs/hr. for Unit 1 and 189 lbs/hr for Unit 2. The Permittee has never violated the NOx concentration limits, the pounds/hour limit or the annual tonnage limit. Annual tons range from 60 to 90 tons well short of the 437 tons annual limit.

The Permittee does operate and maintain a CEMS for NOx and oxygen (O_2) in accordance with COMAR 26.11.01.10 and 11 and has in place, for all CEMS, a Quality Assurance (QA) Plan, which satisfactorily documents operations pursuant to 40 CFR 60, Appendix B as well as 40 CFR Part 75, Appendix D. The Permittee also maintains records of NOx and O_2 and submits quarterly summaries of NOx and O_2 CEMS data to the Department in accordance with Condition No. 14 of the CPCN No. 9341.

C4. - NSPS Subpart GG - Compliance Demonstration

Monitoring requirements for NSPS Subpart GG:

40 CFR 60.334 (a)

Except as provided in paragraph (b) of this section, the Permittee who owns a stationary gas turbine subject to the provisions of this subpart and using water or steam injection to control NOx emissions shall install, calibrate, maintain and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine.

40 CFR 60.334 (b)

The Permittee who owns any stationary gas turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and which uses water or steam injection to control NOx emissions may, as an alternative to operating the continuous monitoring system described in paragraph (a) of this section, install, certify, maintain, operate, and quality-assure a continuous emission monitoring system (CEMS) consisting of NOx and O_2 monitors. If the option to use a CEMS is chosen, the CEMS shall be installed, certified, maintained and operated as follows:

Each CEMS must be installed and certified according to PS 2 and 3 (for diluents) of 40 CFR part 60, appendix B, except that the 7-day calibration drift is based on unit operating days, not calendar days. Appendix F, Procedure 1 is not required. The relative accuracy test audit (RATA) of the NOx and diluent monitors may be performed individually or on a combined basis, *i.e.*, the relative accuracy tests of the CEMS may be performed either:

(i) On a ppm basis (for NOx) and a percent O_2 basis for oxygen; or
(ii) On a ppm at 15 percent O_2 basis; or
(iii) On a ppm basis (for NOx) and a percent CO_2 basis (for a CO_2 monitor that uses the procedures in Method 20 to correct the NOx data to 15 percent O_2

Section 40 CFR 60.334 (a) and 40 CFR 60.334 (b) have direct relevance to Brandywine since it was constructed within the time stated in 40 CFR 60.334 (b**)** and uses water injection to control NOx emissions when burning ULSD fuel oil. Therefore, Brandywine has selected the option of using the installed CEMS for monitoring NOx emissions rather than installing, maintaining and operating a system to measure the ratio of water or steam to fuel being fired in the turbine.

Recordkeeping requirements for NSPS Subpart GG

40 CFR 60.7 (f)

The Permittee who is subject to the provisions of this part shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by this part recorded in a permanent form suitable for inspection."

The Permittee shall summit quarterly summaries of valid CEMS data for NOx and O_2 concentrations. The quarterly reports required above shall be in the format approved by the Department. Valid CEMS data are required for a minimum of 90 percent of the plant operating hours in each quarter.

The Permittee shall submit a quarterly summary report to the Department not later than 45 days following each calendar quarter. The report shall be in a format approved by the Department, and shall include the following:

(1) The cause, periods, and magnitude of all emissions, which exceed the applicable emission standards;
(2) The source downtime including the time and date of the beginning and end of each downtime period and whether the source downtime was planned or unplanned;
(3) The periods and cause of all CEM downtime including records of any repairs, adjustments, or maintenance that may affect the validity of emission data;
(4) Quarterly totals of excess emissions, installation downtime, and CEM downtime during the calendar quarter;
(5) Quarterly quality assurance activities; and
(6) Daily calibration activities that include reference values, actual values, absolute or percent of span differences, and drift status; and
(7) Other information required by the Department that is determined to be necessary to evaluate the data, to ensure that compliance is achieved, or to determine the applicability of this regulation." **[Reference: COMAR 26.11.09.08K(1) and COMAR 26.11.01.11E(2)(C).**

Reporting requirements for NSPS Subpart GG

40 CFR 60.334(j)

For each affected unit required to continuously monitor parameters or emissions or to periodically determine the (sulfur content) or fuel nitrogen content under this subpart, the Permittee shall submit reports of excess emissions and monitor downtime, in accordance with section 60.7(c). Excess emissions shall be reported for all periods of unit operation, including

startup, shutdown and malfunction. For the purpose of reports required under section 60.7(c), periods of excess emissions and monitor downtime that shall be reported are defined as follows:

For turbines using NOx and diluent CEMS:

(1) An hour of excess emissions shall be any unit operating hour in which the 4-hour rolling average NOx concentration exceeds the applicable emission limit in §60.332(a)(1) or (2). For the purposes of this subpart, a "4-hour rolling average NOx concentration" is the arithmetic average of the average NOx concentration measured by the CEMS for a given hour (corrected to 15 percent O_2 and, if required under §60.335(b) (1), to ISO standard conditions) and the three unit operating hour average NOx concentrations immediately preceding that unit operating hour.

(2) A period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour, for either NOx concentration or diluent (or both).

(3) Each report shall include the ambient conditions (temperature, pressure, and humidity) at the time of the excess emission period and (if the owner or operator has claimed an emission allowance for fuel bound nitrogen) the nitrogen content of the fuel during the period of excess emissions. You do not have to report ambient conditions if you opt to use the worst-case ISO correction factor as specified in §60.334(b) (3) (ii), or if you are not using the ISO correction equation under the provisions of §60.335(b) (1) [**Reference: 40 CFR 60.334(j) (1) (iii)**].

40 CFR 60. 334(j) (5)

All reports required under §60.7(c) shall be postmarked by the 30th day following the end of each calendar quarter [**Reference: 40 CFR 60.334(j) (5)**].

Compliance Status:
The Permittee complies with all the NSPS monitoring, recordkeeping and reporting requirements.

C5. - NOx RACT Compliance Demonstration.

Testing and Monitoring Requirements for NOx RACT
The Permittee shall use the data collected from the NOx CEM to demonstrate compliance with the RACT limitation **[Reference: COMAR 26.11.09.08B(2)(a)(i)].** The Permittee shall perform QA/QC procedures for the NOx monitoring system in accordance with 40 CFR Part 75 Appendix D. **[Reference: COMAR 26.11.09.08B(2)(c)]**

Recordkeeping requirement for NOx RACT
The Permittee shall maintain annual fuel use records and records that are necessary to submit with the quarterly emissions report [**References: COMAR 26.11.09.08K(3) and COMAR 26.11.03.06C].**

Reporting Requirement for NOx RACT
The Permittee shall submit a quarterly summary report to the Department not later than 30 days following each calendar quarter. The report shall be in a format approved by the Department, and shall include the following:

(1) The cause, time periods, and magnitude of all emissions which exceed the applicable emission standards;
(2) The source downtime including the time and date of the beginning and end of each downtime period and whether the source downtime was planned or unplanned;
(3) The time periods and cause of all CEM downtime including records of any repairs, adjustments, or maintenance that may affect the validity of emission data;
(4) Quarterly totals of excess emissions, installation downtime, and CEM downtime during the calendar quarter;
(5) Quarterly quality assurance activities; and
(6) Daily calibration activities that include reference values, actual values, absolute or percent of span differences, and drift status; and
(7) Other information required by the Department that is determined to be necessary to evaluate the data, to ensure that compliance is achieved, or to determine the applicability of this regulation." **[Reference: COMAR 26.11.09.08K(1) and COMAR 26.11.01.11E(2)(C).**

Note: The Permittee may submit one report that includes the all required information to satisfy both NOx RACT and CPCN quarterly reporting requirements (See Operational Limitation Reporting Condition G for CPCN). **[Reference: COMAR 26.11.03.06C]**

Compliance Status:
The Permittee complies with the NOx RACT monitoring, recordkeeping and reporting requirements.

C6. - **Cross-State Air Pollution Rule**

The Permittee shall comply with:
The monitoring requirements found in §97.406, §97.430, §97.431, §97.432, and §97.433 for the NOx Annual Trading Program; and §97.506, §97.530, §97.531, §97.532, and §97.533 for the NOx Ozone Season Trading Program;
The recordkeeping requirements found in §97.406, §97.430, and §97.434 for the NOx Annual Trading Program and §97.506, §97.530, and §97.534 for the NOx Ozone Season Trading Program; and

The reporting requirements found in §97.406, §97.430, §97.433 and §97.434 for the NOx Annual Trading Program and §97.506, §97.530, §97.533, and §97.534 for the NOx Ozone Season Trading Program.

C7 Acid Rain Program

There are no standards or limits under the Acid Rain Program for NOx emissions. Only coal fired affected units have NOx limits in the Acid Rain Program. However, Brandywine is required to continuously monitor NOx emissions and report the emissions to the Clean Air Market Group. The NOx monitoring requirements are found in 40 CFR Part 75. Information about emissions can be viewed on EPA's Clean Air Markets Website, http:// www.epa.gov/airmarkets

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Control of Carbon Monoxide Emissions

D. **CPCN No. 9341, Air Quality Section, Condition No. 5**.
Each combustion turbine, except during start-up period, shut-down, malfunction, and Black Start Events shall be limited to no more than the following hourly emissions expressed in units of pounds per hour:

	Natural Gas	LNG	ULSD Fuel Oil
Carbon Monoxide	59	59	71

The CO limitation was based upon the vendor's design guarantees for the turbines.

The performance tests performed in 1996 reported carbon monoxide emissions levels below the permitted limits for both natural gas and fuel oil. For natural gas, the average of three test runs was 20 lbs/hr. for Unit 1and 15 lbs/hr. for Unit 2. For No. 2 fuel oil, the average of three test runs was 0.2 lbs/hr. for Unit 1 and 0.2 lbs/hr. for Unit 2.

Compliance Demonstration Rationale/Discussion
The Permittee shall perform preventative maintenance on the turbines to keep them operating as designed, maintain records of the preventative maintenance, which relate to combustion performance and submit records of the preventative maintenance performed to the Department upon request [**Reference: COMAR 26.11.03.06C**].

Compliance Status
Stack tests confirm that normal operation of the turbines results in CO emissions that are significantly below the allowable limit. To maintain this level of performance, the Permittee performs preventative maintenance on the turbines through a computerized system, which properly maintains and ensures that the turbines operate as designed. The Permittee also

maintains records of the preventative maintenance, which relates to combustion performance and submits the records to the Department upon request.

Control of Volatile Organic Compounds

E. **CPCN No. 9341,** Air Quality Section, Condition No. 5. Each combustion turbine, except during start-up period, shut-down, malfunction, and Black Start Events shall be limited to no more than the following hourly emissions expressed in units of pounds per hour:

	Natural Gas	LNG	ULSD fuel Oil
Volatile Organic Compounds	2	2	5

These limitations were placed in the CPCN because the vendor provided a guarantee that the turbines are designed to achieve these VOC emission limitations.

The performance tests performed in 1996 reported volatile organic compound emissions levels well below the permitted limits for both natural gas and fuel oil. For natural gas, the average of three test runs was 0.8 lbs/hr. for Unit 1and 0.7 lbs/hr. for Unit 2. For No. 2 fuel oil, the average of three test runs was 1.5 lbs/hr. for Unit 1 and 1.2 lbs/hr. for Unit 2.

Compliance Demonstration/Rationale/Discussion:

The Permittee shall perform preventative maintenance on the turbines to keep them operating as designed, maintain records of the preventative maintenance, which relate to combustion performance and submit records of the preventative maintenance performed to the Department upon request [**Reference: COMAR 26.11.03.06C**].

Compliance Status

Stack tests confirm that normal operation of the turbines results in VOC emissions that are significantly below the allowable limit. To maintain this level of performance, the Permittee performs preventative maintenance on the turbines through a computerized system, which properly maintains and ensures that the turbines operate as designed. The Permittee also maintains records of the preventative maintenance, which relates to combustion performance and submits the records to the Department upon request.

Control of Particulate Matter Emissions

F. **CPCN No. 9341**, **Air Quality Section, Condition No. 5.**
Each combustion turbine, except during start-up period, shutdown, malfunction, and Black Start Events shall be limited to no more than the following hourly emissions expressed in units of pounds per hour:

	Natural Gas	LNG	ULSD fuel
PM_{10}	7	7	15
Total Particulate	7	7	15

The particulate limitation was based on the vendor's design guarantee for the turbines.

The performance tests performed in 1996 reported particulate emissions levels (including PM10) well below the permitted limits for both natural gas and fuel oil. For natural gas, the average of three test runs was 1.97 lbs/hr. for Unit 1and 2.66 lbs/hr. for Unit 2. For fuel oil, the average of three test runs was 5.55 lbs/hr. for Unit 1 and 4.41 lbs/hr. for Unit 2.

Compliance Demonstration/ Rationale/Discussion:
The Permittee shall perform preventative maintenance on the turbines to keep them operating as designed, maintain records of the preventative maintenance, which relate to combustion performance, and submit records of the preventative maintenance performed to the Department upon request [**Reference: COMAR 26.11.03.06C**].

Compliance Status
Stack tests confirm that normal operation of the turbines results in particulate matter emissions that are significantly below the allowable limit. To maintain this level of performance, the Permittee performs preventative maintenance on the turbines through a computerized system, which properly maintains and ensures that the turbines operate as designed. The Permittee also maintains records of the preventative maintenance, which relates to combustion performance and submits the records to the Department upon request.

Operational Limitations

G1. **CPCN Case No. 9341, Air Quality Section, Condition No. 9**
The combustion turbines shall generate electricity using natural gas or LNG only except as otherwise provided for in these conditions:

(a) When the fuel delivery to the turbines is interrupted or curtailed, the facility may burn ULSD fuel oil but shall be limited to 143 tons of NO_X when burning ULSD fuel oil;

(b) If the facility has reached its 143 tons limit and there is a PJM system emergency as defined in Condition No. 11 and natural gas is unavailable, the facility may burn ULSD fuel oil; and

(c) Under no circumstances, however, may the facility burn ULSD fuel oil for more than 2,400 turbine hours.

For the purposes of this condition, a year is defined as November 1 through October 31. Natural gas/LNG service interruptions shall be verified by a letter each year from Brandywine's natural gas/LNG supplier identifying the dates on which service was restricted. Brandywine will ensure that the Department receives a copy of this letter within 60 days of the start of each New Year.

G2. **CPCN Case No. 9341, Air Quality Section, Condition No. 11**
For the purposes of Conditions Nos. 6 and 9 of the CPCN, a PJM system emergency is operation during reserve shortages and refers to Maximum Generation Emergency, as defined in Section 2.0 of PJM Manual 35: Definitions and Acronyms, Revision 22 Effective date 2/28/2013.

G3. **CPCN Case No. 9341, Air Quality Section, Condition No. 7**
Except for periods of startup, shutdown periods and Black Start Events, each combustion turbine unit shall operate only when the unit, for natural gas or LNG firing, is in DLN premix mode, or when firing ULSD fuel oil, water injection is engaged.

Note that after the initiation of premix steady state while firing natural gas or LNG and upon initiation of water injection while firing ULSD fuel oil, an emissions monitoring stabilization period of up to 17 minutes is required to accommodate exhaust gas transit time from the exit of the combustion system to the CEMS.

Compliance Demonstration
The Permittee shall maintain records of the hours that the turbines burn ULSD fuel oil and record periods, except for startups, shutdowns, and Black Start Events, when each combustion turbine generator operates without water injection engaged. **[Reference: COMAR 26.11.03.06C].**

The Permittee shall in addition, submit the quarterly reports within 45 days of the end of each calendar quarter, and shall include at least the following for each turbine (monthly summaries):
(a) The total hours of operation;

(b) The number of hours of operation burning ULSD fuel oil;
(c) The total amount of ULSD fuel oil burned, in units of gallons/hour and MMBtu/hour during the quarter;
(d) The number of hours of operation burning natural gas and LNG;
(e) The total amount of natural gas and LNG burned, in units of pound per hour and MMBtu per hour during the quarter;
(f) Times of start-up and shutdown, and Black Start Events;
(g) The megawatts of electricity produced by each turbine on an hourly basis;
(h) Maximum hourly and average hourly NOx emissions, in units of ppmvd at 15 percent oxygen and pounds per hour, and the cumulative annual NOx emissions;
(i) Any emissions in excess of NOx concentrations specified in this permit, including the amount of the emissions, the date(s) on which the excess emissions occurred, the length of time over which the excess emissions occurred, the reason(s) why the excess emissions occurred, and the corrective action taken, if required, to ensure that excess emissions do not occur in the future; and
(j) Any periods, except startup and shutdowns and Black Start Events, that the turbines operated for natural gas or LNG firing, and not in DLN premix mode or when firing ULSD fuel oil, and water injection is not engaged.

The quarterly report as required above shall be in the format approved by the Department. Valid CEMS data are required for a minimum of 90 percent of the plant operating hours in each quarter **[References**: **CPCN 9341, Conditions Nos. 13 and 14]**.

Compliance Status
The Permittee complies with the stated requirements and maintains records of the hours that the turbines burn (ULSD) fuel oil except for startups and shutdowns, when each combustion turbine generator operates and water injection is not engaged.

For calendar year, 2018 the two combustion turbines combined operated for a total of 381 hours of operation on fuel oil. For the same timeframe, the turbines operated a total of 11,996 hours on natural gas. The total hours of operation when burning No. 2 fuel oil are insignificant when compared to the maximum allowable 2400 hours per year for which No. 2 fuel oil may be burned. (Condition No. 9 of the CPCN #9341)

Emissions Unit EU-3
Emission Unit EU-3 is one (1) Caterpillar diesel engine Model C175-20 rated at 4000 kW, burning ULSD fuel oil used for Black Start Events.

A. Control of Visible Emissions

A1. **COMAR 26.11.09.05E (2)** Emissions During Idle Mode. A person may not cause or permit the discharge of emissions from any engine, operating at idle, greater than 10 percent opacity.

A2. **COMAR 26.11.09.05E (3)** Emissions During Operating Mode. A person may not cause or permit the discharge of emissions from any engine, operating at other than idle conditions, greater than 40 percent opacity.

A3. **COMAR 26.11.09.05E (4)** Exceptions.

(a) Section E(2) of this regulation does not apply for a period of 2 consecutive minutes after a period of idling of 15 consecutive minutes for the purpose of clearing the exhaust system.

(b) Section E(2) of this regulation does not apply to emissions resulting directly from cold engine start-up and warm-up for the following maximum periods:
(i) Engines that are idled continuously when not in service: 30 minutes;
(ii) All other engines: 15 minutes.

(c) Section E(2) and (3) of this regulation do not apply while maintenance, repair, or testing is being performed by qualified mechanics

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Compliance Demonstration

(1) The Permittee shall:
(a) Properly operate and maintain the engine; and
(b) Maintain an operations manual and preventive maintenance plan. **[Authority: COMAR 26.11.03.06C].**

(2) The Permittee shall properly operate and maintain the engine in a manner to minimize visible emissions. **[Authority: COMAR 26.11.03.06C]** and shall operate and maintain the stationary CI internal combustion engine according to the manufacturer's written instructions or procedures developed by the owner or operator that are approved by the engine manufacturer. **[Authority**: **§60.4211(a)(1)].**

NOTE: All records must be maintained for a period of 5 years. **[Reference: COMAR 26.11.03.06.C (5) (g)].**

The Permittee shall maintain records of the preventive maintenance that relates to combustion process performed on the engine on site for at least 5 years and make the records available to the Department upon request. The Permittee shall also retain the operations manual on site and make it available to the Department upon request [**Authority: COMAR 26.11.03.06C].**

The Permittee shall report incidents of visible emissions in accordance with Condition 4 of Section III "Report of Excess Emissions and Deviation. [**Reference: COMAR 26.11.03.06C**].

Compliance Status

The Department conducted a full compliance inspection of the facility on April 08, 2019. Inspection of the records indicated that the latest Method 9 Observation was performed on August 18, 2018 and no visible emissions were observed during the test. Visible emissions observations conducted in prior years also showed no visible emissions. The Permittee performs preventative maintenance on the engine and ensures that the engine operates as designed. The Permittee also maintains records of the preventative maintenance, which relates to combustion performance and submits the records to the Department upon request.

B. Control of Sulfur Dioxide Emissions

B1. **CPCN Case No. 9341, Air Quality Section, Condition No. 8**, which limits sulfur content in ULSD fuel oil to 0.0015 wt %.

B2. **COMAR 26.11.09.07A(2)(b) -** Areas III and IV - Sulfur Content Limitations for Fuel. "A person may not burn, sell, or make available for sale any fuel with a sulfur content by weight in excess of or which otherwise exceeds 0.3 percent by weight."

B3. **§60.4207(b) -** owners and operators of stationary CI ICE subject to this subpart with a displacement of less than 30 liters per cylinder that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR 80.510(b) for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to October 1, 2010, may be used until depleted. Note: 40 CFR 80.510(b) requires 15 ppm sulfur in fuel limitation

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Compliance Demonstration

(1) The Permittee shall perform sampling and analysis of the "as fired" sulfur content of the ULSD fuel oil to determine the percentage of sulfur by weight in the fuel oil. The sampling procedures shall follow the requirements of CPCN No. 9341, Condition No. 8 as prescribed in 40 CFR 75 Appendix D, Sec. 2.2. [**Reference: CPCN No. 9341, Condition No. 8, Air Quality Section**].

(2) The Permittee shall obtain fuel supplier's certification, which includes the name of the oil supplier and statement from the fuel supplier that the distillate fuel oil complies with the limitation of 0.3% by weight of the sulfur content in the fuel oil. **[Authority: COMAR 26.11.03.06C].**

(3) The Permittee shall comply with requirements under 40 CFR 60 subpart IIII.

Note: The monitoring requirements for complying with the CPCN requirements shall be the basis for complying with both the COMAR and 40 CFR 60 subpart IIII requirements. **[Authority: COMAR 26.11.03.06C].**

The Permittee shall maintain records of fuel sampling and analysis for the "as fired" sulfur content of the ULSD fuel oil utilized in the engine for at least five years. [**Reference: CPCN No. 9341, Condition No. 14, Air Quality Section**].
The Permittee shall maintain records of fuel suppliers' certifications of the percent sulfur content in the fuel on site for at least five years and shall make the records available to the Department upon request. The fuel oil certification report must contain the type, quantities, and analyses of all fuels burned. **[Authority: COMAR 26.11.09.07C].**

The Permittee shall submit, within 45 days of the end of each quarter, the result of the sulfur content of the fuel to the Department [**Reference: CPCN No. 9341, Air Quality Section, Condition No. 14**].

The Permittee shall submit the fuel supplier certification or a copy of the sulfur in fuel analyses to the Department upon request. **[Authority: COMAR 26.11.09.07C].**
Note 1: For any calendar quarter during which no delivery of fuel oil is received, the quarterly report shall state that no fuel was received during the quarter.
Note 2: Note: The Permittee may submit one report that includes the required information to satisfy RACT and CPCN quarterly reporting requirements (See Reporting Condition G for CPCN). **[Reference: COMAR 26.11.03.06C]**

Compliance Status
The Permittee performs sampling and analysis of the "as fired" sulfur content of the ULSD fuel oil to determine the percentage of sulfur by weight in the fuel oil. The sampling procedures follows the requirements of CPCN No. 9341, Condition No. 8 as prescribed in 40 CFR 75 Appendix D, Sec. 2.2. The Permittee obtains fuel supplier's certification, which includes the name of the oil supplier and statement from the fuel supplier that the distillate fuel oil complies with the limitation of 0.3% by weight of the sulfur content in the fuel oil, maintains records of fuel sampling and analysis for the "as fired" sulfur content of the ULSD fuel oil utilized in the engine for at least five years and submits the fuel supplier certification or a copy of the sulfur in fuel analyses to the Department upon request.

C. Control of Nitrogen Oxides

C1. COMAR 26.11.36.03 - Requirements for Stationary Engines.

A. "The owner or operator of an engine is subject to requirements under 40 CFR Part 63 Subpart ZZZZ, as applicable.

B. The owner or operator of an engine is subject to requirements under 40 CFR Part 60 Subpart IIII. In May 2015, the United States Court of Appeals for the District of Columbia Circuit vacated paragraphs 40 CFR 60.4211(f)(2)(ii)-(iii) and 63.6640(f)(2)(ii)-(iii). Therefore, engines subject to this chapter do not have to comply with those provisions."
Note: Black Start Events are periods of emergencies.

C2. NOx RACT Requirements

COMAR 26.11.09.08G - Requirements for Fuel-Burning Equipment with a Capacity Factor of 15 percent or less.

(1) A person who owns or operates fuel-burning equipment with a capacity factor (as defined in 40 CFR Part 72.2) of 15 percent or less shall:

(a) Provide certification of the capacity factor of the equipment to the Department in writing;

(b) For fuel-burning equipment that operates more than 500 hours during a calendar year, perform a combustion analysis and optimize combustion at least once annually;

(c) Maintain the results of the combustion analysis and any stack tests at the site for at least 2 years and make these results available to the Department and the EPA upon request;

(d) Require each operator of an installation, except combustion turbines, to attend operator training programs at least once every 3 years, on combustion optimization that are sponsored by the Department, the EPA, or equipment vendors; and

(e) Maintain a record of training program attendance for each operator at the site, and make these records available to the Department upon request."

2**. COMAR 26.11.09.08B (5) -** Operator Training**.**

(a) **COMAR 26.11.09.08B (5)(a)** states that "for purposes of this regulation, the equipment operator to be trained may be the person who maintains the equipment and makes the necessary adjustments for efficient operation; and .

(b) **COMAR 26.11.09.08B (5)**(b) states that the operator-training course sponsored by the Department shall include an in-house training course that is approved by the Department."

C3. **NSPS Subpart IIII Limitations**

§60.4205(b) - Owners and operators of 2007 model year and later emergency stationary CI ICE with a displacement of less than 30 liters per cylinder that are not fire pump engines must comply with the emission standards for new nonroad CI engines in §60.4202, for all pollutants, for the same model year and maximum engine power for their 2007 model year and later emergency stationary CI ICE.

§60.4202(b) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pump engines to the emission standards specified in paragraphs (b)(1) through (2) of this section.

(1) For 2007 through 2010 model years, the emission standards in table 1 to this subpart, for all pollutants, for the same maximum engine power. - **N/A**

(2) For 2011 model year and later, the certification emission standards for new nonroad CI engines for engines of the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants.

Compliance Demonstration

The Permittee, owner or operator of a 2007 model year and later stationary CI internal combustion engine and must comply with the emission standards specified in §60.4204(b) or §60.4205(b ……..must comply by purchasing an engine certified to the emission standards in §60.4204(b), or §60.4205(b) …..as applicable for the same model year and … engine power. The engine must be installed and configured according to the manufacturer's emission-related specifications, except as permitted in paragraph (g) of this section. [**Authority: §60.4211(c)].**

The Permittee shall:
Perform a combustion analysis for each combustion unit at least once each calendar year and optimize combustion based on analysis. **[Authority: COMAR 26.11.09.08G (1)(b)].**

Require each installation operators to attend operator-training program on combustion optimization that are sponsored by the Department, U.S. EPA, or equipment vendors, once every three years. **[Authority: COMAR 26.11.03.06C and COMAR 26.11.09.08G(1)(d)].** Additionally**,** a Permittee who owns or operates fuel-burning equipment with a capacity factor (as defined in 40 CFR Part 72.2) of 15 percent or less shall provide certification of the capacity factor of the equipment to the Department in writing. **[Authority: COMAR 26.11.03.06C and COMAR 26.11.09.08G (1)(a)].**

Continuously monitor operating parameters required to be established under **§60.4211(d)** to ensure the stationary internal combustion engine continues to meet the applicable emission standards **[Authority: §60.4211(d)(2)].**

The Permittee shall maintain a record of the date and time of the operation of the generator. The Permittee shall also:

(a) Maintain records of the result of the combustion analysis at the site and make the records available to the Department and EPA upon request. **[Authority: COMAR 26.11.09.08G(c)].**
(b) Prepare and maintain a record of training program attendance for each operator at the site and make these records available to the Department upon request; **[Authority: COMAR 26.11.09.08E(1)(e) and COMAR 26.11.09.08G (1)(e)].**
(c) Records of the calculated capacity factors on site for at least five years. **[Authority: COMAR 26.11.09.08G (1)(a)].**
(d) The Permittee shall maintain annual fuel use records and records that are necessary to submit with the quarterly emissions report [**Authority: COMAR 26.11.09.08K(3) and COMAR 26.11.03.06C**].

The Permittee shall maintain records of the initial performance test, if a test is conducted, to demonstrate initial compliance with applicable emission standards and in accordance with §60.4212 and shall maintain records of the established operating parameters to be monitored continuously to ensure the stationary internal combustion engine continues to meet the emission standards. **[Authority: COMAR 26.11.03.06C and §60.4211(f)].**

Compliance Status
The Permittee complies with the requirements of these regulations.

D. Control of NESHAP

40 CFR Part 63 Subpart ZZZZ (NESHAP) - See NSPS Subpart IIII limitations.
Note: MACT for Subpart ZZZZ - **§63.6590(c)(1) Stationary RICE subject to Regulations under 40 CFR 60.**
"An affected source that meets any of the criteria in paragraphs (c) (1) through (7) of this section must meet the requirements of this part by meeting the requirement of 40 CFR part 60 Subpart IIII, for compression ignition engine or 40 CFR part 60 Subpart JJJJ, for spark ignition engines. No further requirements apply for such engines under this part" **(Ref: 40 CFR §63.6590(c)(1)).**

E. Operational Requirements

E1. **§60.4206 -** Owners and operators of emergency stationary CI ICE must operate and maintain stationary CI ICE so as to achieve the emission standards as required in §60.4205 over the entire life of engine.

E2. **§60.4207** - Owners and operators of stationary CI ICE subject to this subpart with a displacement of less than 30 liters per cylinder that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR 80.510(b) for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to October 1, 2010, may be used until depleted.

E3. **§60.4211(a) -** The Permittee, owner and operator of a stationary CI ICE subject to the emissions standard of 40 CFR Part 60, Subpart IIII must do all of the following, except as permitted under paragraph (g) of this section:
(1) Operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's emission-related written instructions;
(2) Change only those emission-related settings that are permitted by the manufacturer; and
(3) Meet the requirements of 40 CFR parts 89, 94 and/or 1068, as they apply to you.

E4. **§60.4211(f) -** Owners and operators of an emergency stationary ICE must operate the emergency stationary ICE according to the requirements in paragraphs (f)(1), (f)(2)(i) and

(f)(3) of this section. In order for the engine to be considered an emergency stationary ICE under this subpart, any operation other than emergency operation, maintenance and testing, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1), (f)(2)(i) and (f)(3) of this section, is prohibited. If you do not operate the engine according to the requirements in paragraphs (f)(1), (f)(2)(i) and (f)(3) of this section, the engine will not be considered an emergency engine under this subpart and must meet all requirements for non-emergency engines.

(1) There is no time limit on the use of emergency stationary ICE in emergency situations.

(2) You may operate your emergency stationary ICE for any combination of the purposes specified in paragraphs (f)(2)(i) of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraph (f)(3) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (f)(2)(i).

(i) Emergency stationary ICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency ICE beyond 100 hours per calendar year.

(3) Emergency stationary ICE may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing provided in paragraph (f)(2)(i) of this section. Except as provided in paragraph (f)(3)(i) of this section, the 50 hours per calendar year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(i) The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met:

(A) The engine is dispatched by the local balancing authority or local transmission and distribution system operator;

(B) The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.

(C) The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.

(D) The power is provided only to the facility itself or to support the local transmission and distribution system.

(E) The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

Compliance Demonstration

The Permittee, owner or operator, must meet the monitoring requirements of this section. In addition, you must also meet the monitoring requirements specified in §60.4211.

(a) If you are an owner or operator of an emergency stationary CI internal combustion engine that does not meet the standards applicable to non-emergency engines, you must install a non-resettable hour meter prior to startup of the engine.

(b) If you are an owner or operator of a stationary CI internal combustion engine equipped with a diesel particulate filter to comply with the emission standards in §60.4204, the diesel particulate filter must be installed with a backpressure monitor that notifies the owner or operator when the high backpressure limit of the engine is approached. - **N/A** **[Authority: §60.4209].**

The Permittee shall maintain, on site, a record of operation of the engine to include fuel consumption, the hours of operation and purpose of operation - whether emergency or non-emergency situations such as maintenance and testing, etc - as necessitated by the operating requirements of §60.4211(f) and make the record available to the Department upon request. **[Authority: COMAR 26.11.03.06C and §60.4211(f)].**

The Permittee shall submit semi-annually or as appropriate, a report of all relevant operating records to include the hours of operation and purpose of operation of the engine - whether emergency or non-emergency situations such as maintenance and testing, etc – as necessitated by the operating requirements of §60.4211(f). **[Authority: COMAR 26.11.03.06C and §60.4211(f)].**

Compliance Status
The Permittee, owner or operator complies with the requirements of these regulations.

Section 112(r), Accidental Releases
The Permittee is not subject to the requirements under Section 112 (r).

1990 CAAA, Title IV, Acid Rain
The Permittee is an affected source under the 1990 CAAA, Title IV Acid Rain Program and must comply with the Acid Rain Phase II Permit, which is being issued in conjunction with this Title V permit.

Title VI, Ozone Depleting Substances
Not applicable, the Facility does not service or repair its window air-conditioning units.

Compliance Schedule
Not applicable, the Permittee is in compliance.

Permit Shield
A Permit Shield shall cover the applicable requirements identified for the emissions unit listed in the "Regulatory Review/Technical Review/Compliance Methodology" section above.

SECTION V INSIGNIFICANT ACTIVITIES

Brandywine has identified the following emissions units as insignificant activity in accordance with the requirements of Part 70 Permit Program. The applicable Clean Air Act requirements if any are listed below the insignificant activity.

(1) No. 1 Stationary internal combustion engines with an output less than 500 brake horsepower (373 kilowatts) and which are not used to generate electricity for sale or for peak or load shaving;

The diesel fuel fired fire protection engine/pump is subject to the following requirements:

(a) **COMAR 26.11.09.05B(2) –** "Emissions During Idle Mode. A person may not cause or permit the discharge of emissions from any engine, operating at idle, greater than 10 percent opacity."

(b) **COMAR 26.11.09.05B(3) – "**Emissions During Operating Mode. A person may not cause or permit the discharge of emissions from any engine, operating at other than idle conditions, greater than 40 percent opacity."

(c) **COMAR 26.11.09.05B(4)** "Exceptions:

(i) Section B(2) does not apply for a period of 2 consecutive minutes after a period of idling of 15 consecutive minutes for the purpose of clearing the exhaust system;

(ii) Section B(2) does not apply to emissions resulting directly from cold engine start-up and warm-up for the following maximum periods:

(1) Engines that are idled continuously when not in service: 30 minutes,
(2) All other engines: 15 minutes; and

(iii) Section B(2) and (3) does not apply while maintenance, repair, or testing is being performed by qualified mechanics."

(d) **COMAR 26.11.09.07A(2)(b)** " In Areas III and IV - Sulfur Content Limitations for Fuel. A person may not burn, sell, or make available for sale any fuel with a sulfur content by weight in excess of or which otherwise exceeds 0.3 percent by weight."

(2) ✓ Space heaters utilizing direct heat transfer and used solely for comfort heat;

(3) No. 75 Unheated VOC dispensing containers or unheated VOC rinsing containers of 60 gallons (227 liters) capacity or less;

(4) Containers, reservoirs, or tanks used exclusively for:

(a) ✓ Storage of butane, propane, or liquefied petroleum, or natural gas;

(b) No. 20 Storage of lubricating oils;

(c) No. 3 Storage of ULSD fuel oil;

(d) No. 30 The storage of VOC normally used as solvents, diluents, thinners, inks, colorants, paints, lacquers, enamels, varnishes, liquid resins, or other surface coatings and having individual capacities of 2,000 gallons (7.6 cubic meters) or less;

(5) ✓ Certain recreational equipment and activities, such as fireplaces, barbecue pits and cookers, fireworks displays, and kerosene fuel use;

SECTION VI STATE ONLY ENFORCEABLE CONDITIONS

The Permittee is subject to the following State-only enforceable requirements:

Units EU-1 and EU-2: Combined cycle electric generating units consisting of two GE Frame 7EA combustion turbines (CTs) rated at 84 MW each, two (2) unfired HRSGs, and one (1) SG rated at 80 MW for a total generating electric capacity of 248 MW.

Applicable Regulations/Limits:

1. **COMAR 26.11.06.08**
   "An installation or premises may not be operated or maintained in such a manner that a nuisance or air pollution is created. Nothing in this regulation relating to the control of emissions may in any manner be construed as authorizing or permitting the creation of, or maintenance of, nuisance or air pollution."

2. **COMAR 26.11.06.09**
   "A person may not cause or permit the discharge into the atmosphere of gases, vapors, or odors beyond the property line in such a manner that a nuisance or air pollution is created."

3. **COMAR 26.09.01, .02, .03, and .04** - Maryland's CO2 Budget and Trading Program, which requires the Permittee to comply with the provisions and requirements of Maryland's CO_2 Budget and Trading Program. The Permittee shall comply with the CO_2 Budget and Trading Permit that is attached to the Part 70 permit. See Appendix B.

DRAFT PERMIT

Wes Moore
Governor

Serena McIlwain
Secretary

Air and Radiation Administration
1800 Washington Boulevard, Suite 720
Baltimore, MD 21230

☐ Construction Permit ☒ Part 70 Operating Permit

PERMIT NO.:
24-033-0220

DATE ISSUED: _____

PERMIT FEE:
To Be Paid in Accordance With
COMAR 26.11.02.19B(b)

EXPIRATION DATE:
January 31, 2027

LEGAL OWNER & ADDRESS

KMC Thermo, LLC
1111 Fannin 11th Floor
Houston, TX 77002
Attn: Michael Fulcher, Asset Manager

SITE

Brandywine Power Facility
16400 Mattawoman Drive
Brandywine, MD 20613-8089
Prince George's County
033-02200
AI# 9909

SOURCE DESCRIPTION

Combined Cycle Facility

This source is subject to the conditions described on the attached pages.

Program Manager

Director, Air and Radiation Administration

BRANDYWINE POWER FACILITY
16400 MATTAWOMAN DRIVE
BRANDYWINE, MD 20613
DRAFT PART 70 OPERATING PERMIT 24-033-02200

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SECTION I SOURCE IDENTIFICATION

1. DESCRIPTION OF FACILITY

Brandywine Power Facility (Brandywine), formerly known as Panda Brandywine Power Plant, was acquired from Panda Brandywine, LLC on June 1, 2014 by KMC Thermo, LLC. KMC is located in Houston Texas. The Brandywine facility is a nominal 230 megawatts (MW) electric co-generation facility located two miles south of Brandywine in Prince George's County. The facility consists of two combined-cycle units (Emissions Units 1 and 2 [EU-1 and EU-2]). Each unit is comprised of a General Electric (GE) Frame 7EA-DLN1 combustion turbine (CT) rated at 84 MW and an unfired heat recovery steam generator (HRSG). Steam produced by the HRSGs is routed to a common steam turbine (ST) for generation of additional electricity. Brandywine also installed an emergency generator as part of making the facility Black Start capable (Emissions Unit 3[EU-3]), which is a Caterpillar diesel engine Model C175-20 rated at 4000 kW. The EU-3 will be fired exclusively on Ultra Low-Sulfur Diesel fuel. The unit is fully installed and operational.

The Maryland Public Service Commission (PSC) issued a Certificate of Public Convenience and Necessity (CPCN) to Panda Brandywine, LLC on September 5, 1994; PSC Case #8488. The facility began commercial operation on October 31, 1996. The facility produces electricity for distribution by the Potomac Electric Power Company (PEPCO). The applicable SIC Code for the facility is 4911 - Electric Services. The project was subject to major New Source Review (NSR), including Prevention of Significant Deterioration (PSD), and Non-Attainment NSR. Approval requirements pertaining to those air quality programs were specified in CPCN. In February 2014, Brandywine applied for a CPCN to add “Black Start” capability. To make the facility Black Start capable an emergency generator was installed (EU-3). This request was docketed as PSC Case # 9341. The PSC order incorporated all previous conditions from Case # 8488. The CPCN was issued on July 10, 2014.

Ancillary facilities include a two million gallon Ultra Low-Sulfur Diesel (ULSD) fuel storage tank, a re-circulating cooling water system, and miscellaneous support equipment. The facility utilizes pipeline natural gas (NG) or liquefied natural gas (LNG) as its primary fuel source with ULSD (0.0015 weight percent) fuel serving as a backup fuel. The combustion turbines are equipped with dry low NOx burners for natural gas firing and water injection for controlling NOx emissions when firing ULSD fuel. Brandywine uses natural gas or liquefied natural gas ninety-nine percent of the time and uses ULSD fuel occasionally to ascertain the reliability and availability of the combustion turbines when burning ULSD fuel and during Black Start Events. Brandywine will likely continue this pattern of fuel use.

2. FACILITY INVENTORY LIST

Brandywine has identified the following emissions units shown in Table 1 as subject to the Title V Operating Permit program.

Table 1 - Emissions Units

MDE Registration No.	Emissions Unit No	Emission Unit Description	Date Installed
033-2200-5-0844	EU-1	One (1) GE Frame 7EA CT rated at 84 MW.	June 1996
033-2200-5-0845	EU-2	One (1) GE Frame 7EA CT rated at 84 MW.	June 1996
033-2200-9-1465	EU-3	One (1) Caterpillar diesel engine Model C175-20 rated at 4000 kW	May 2015

SECTION II GENERAL CONDITIONS

1. DEFINITIONS

[COMAR 26.11.01.01] and [COMAR 26.11.02.01]

The words or terms in this Part 70 permit shall have the meanings established under COMAR 26.11.01 and .02 unless otherwise stated in this permit.

2. ACRONYMS

ARA	Air and Radiation Administration
BACT	Best Available Control Technology
Btu	British thermal unit
CAA	Clean Air Act
CAM	Compliance Assurance Monitoring
CEM	Continuous Emissions Monitor
CFR	Code of Federal Regulations
CO	Carbon Monoxide
COMAR	Code of Maryland Regulations
EPA	United States Environmental Protection Agency
FR	Federal Register
gr	grains
HAP	Hazardous Air Pollutant
MACT	Maximum Achievable Control Technology
MDE	Maryland Department of the Environment
MVAC	Motor Vehicle Air Conditioner
NESHAPS	National Emission Standards for Hazardous Air Pollutants
NO_x	Nitrogen Oxides
NSPS	New Source Performance Standards
NSR	New Source Review
OTR	Ozone Transport Region
PM	Particulate Matter
PM10	Particulate Matter with Nominal Aerodynamic Diameter of 10 micrometers or less
ppm	parts per million
ppb	parts per billion
PSD	Prevention of Significant Deterioration
PTC	Permit to construct
PTO	Permit to operate (State)
SIC	Standard Industrial Classification
SO_2	Sulfur Dioxide

TAP	Toxic Air Pollutant
tpy	tons per year
VE	Visible Emissions
VOC	Volatile Organic Compounds

3. EFFECTIVE DATE

The effective date of the conditions in this Part 70 permit is the date of permit issuance, unless otherwise stated in the permit.

4. PERMIT EXPIRATION

[COMAR 26.11.03.13B (2)]

Upon expiration of this permit, the terms of the permit will automatically continue to remain in effect until a new Part 70 permit is issued for this facility provided that the Permittee has submitted a timely and complete application and has paid applicable fees under COMAR 26.11.02.16.

Otherwise, upon expiration of this permit the right of the Permittee to operate this facility is terminated.

5. PERMIT RENEWAL

[COMAR 26.11.03.02B (3)] and [COMAR 26.11.03.02E]

The Permittee shall submit to the Department a completed application for renewal of this Part 70 permit at least 12 months before the expiration of the permit. Upon submitting a completed application, the Permittee may continue to operate this facility pending final action by the Department on the renewal.

The Permittee, upon becoming aware that any relevant facts were omitted or incorrect information was submitted in the permit application, shall submit such supplementary facts or corrected information no later than 10 days after becoming aware that this occurred. The Permittee shall also provide additional information as necessary to address any requirements that become applicable to the facility after the date a completed application was submitted, but prior to the release of a draft permit. This information shall be submitted to the Department no later than 20 days after a new requirement has been adopted.

6. CONFIDENTIAL INFORMATION

[COMAR 26.11.02.02G]

In accordance with the provisions of the State Government Article, Sec. 10-611 et seq., Annotated Code of Maryland, all information submitted in an application shall be considered part of the public record and available for inspection and copying unless the Permittee claims that the information is confidential when it is submitted to the Department. At the time of the request for inspection or copying, the Department will make a determination with regard to the confidentiality of the information. The Permittee, when requesting confidentiality, shall identify the information in a manner specified by the Department and, when requested by the Department, promptly provide specific reasons supporting the claim of confidentiality. Information submitted to the Department without a request that the information be deemed confidential may be made available to the public. Subject to approval of the Department, the Permittee may provide a summary of confidential information that is suitable for public review. The content of this Part 70 permit is not subject to confidential treatment.

7. PERMIT ACTIONS

[COMAR 26.11.03.06E (3)] and [COMAR 26.11.03.20(A)]

This Part 70 permit may be revoked or reopened and revised for cause. The filing of an application by the Permittee for a permit revision or renewal; or a notification of termination, planned changes or anticipated noncompliance by the facility, does not stay a term or condition of this permit.

The Department shall reopen and revise, or revoke the Permittee's Part 70 permit under the following circumstances:

a. Additional requirements of the Clean Air Act become applicable to this facility and the remaining permit term is 3 years or more;

b. The Department or the EPA determines that this Part 70 permit contains a material mistake, or is based on false or inaccurate information supplied by or on behalf of the Permittee;

c. The Department or the EPA determines that this Part 70 permit must be revised or revoked to assure compliance with applicable requirements of the Clean Air Act; or

d. Additional requirements become applicable to an affected source under the Federal Acid Rain Program.

8. PERMIT AVAILABILITY

[COMAR 26.11.02.13G]

The Permittee shall maintain this Part 70 permit in the vicinity of the facility for which it was issued, unless it is not practical to do so, and make this permit immediately available to officials of the Department upon request.

9. REOPENING THE PART 70 PERMIT FOR CAUSE BY THE EPA

[COMAR 26.11.03.20B]

The EPA may terminate, modify, or revoke and reissue a permit for cause as prescribed in 40 CFR §70.7(g)

10. TRANSFER OF PERMIT

[COMAR 26.11.02.02E]

The Permittee shall not transfer this Part 70 permit except as provided in COMAR 26.11.03.15.

11. REVISION OF PART 70 PERMITS – GENERAL CONDITIONS

[COMAR 26.11.03.14] and [COMAR 26.11.03.06A (8)]

a. The Permittee shall submit an application to the Department to revise this Part 70 permit when required under COMAR 26.11.03.15 -.17.

b. When applying for a revision to a Part 70 permit, the Permittee shall comply with the requirements of COMAR 26.11.03.02 and .03 except that the application for a revision need include only information listed that is related to the proposed change to the source and revision to the permit. This information shall be sufficient to evaluate the proposed change and to determine whether it will comply with all applicable requirements of the Clean Air Act.

c. The Permittee may not change any provision of a compliance plan or schedule in a Part 70 permit as an administrative permit amendment or as a

minor permit modification unless the change has been approved by the Department in writing.

d. A permit revision is not required for a change that is provided for in this permit relating to approved economic incentives, marketable permits, emissions trading, and other similar programs.

12. SIGNIFICANT PART 70 OPERATING PERMIT MODIFICATIONS

[COMAR 26.11.03.17]

The Permittee may apply to the Department to make a significant modification to its Part 70 Permit as provided in COMAR 26.11.03.17 and in accordance with the following conditions:

a. A significant modification is a revision to the federally enforceable provisions in the permit that does not qualify as an administrative permit amendment under COMAR 26.11.03.15 or a minor permit modification as defined under COMAR 26.11.03.16.

b. This permit does not preclude the Permittee from making changes, consistent with the provisions of COMAR 26.11.03, that would make the permit or particular terms and conditions of the permit irrelevant, such as by shutting down or reducing the level of operation of a source or of an emissions unit within the source. Air pollution control equipment shall not be shut down or its level of operation reduced if doing so would violate any term of this permit.

c. Significant permit modifications are subject to all requirements of COMAR 26.11.03 as they apply to permit issuance and renewal, including the requirements for applications, public participation, and review by affected states and EPA, except:

(1) An application need include only information pertaining to the proposed change to the source and modification of this permit, including a description of the change and modification, and any new applicable requirements of the Clean Air Act that will apply if the change occurs;

(2) Public participation, and review by affected states and EPA, is limited to only the application and those federally enforceable terms and conditions of the Part 70 permit that are affected by the significant permit modification.

d. As provided in COMAR 26.11.03.15B(5), an administrative permit amendment may be used to make a change that would otherwise require a significant permit modification if procedures for enhanced preconstruction review of the change are followed that satisfy the requirements of 40 CFR 70.7(d)(1)(v).

e. Before making a change that qualifies as a significant permit modification, the Permittee shall obtain all permits-to-construct and approvals required by COMAR 26.11.02.

f. The Permittee shall not make a significant permit modification that results in a violation of any applicable requirement of the Clean Air Act.

g. The permit shield in COMAR 26.11.03.23 applies to a final significant permit modification that has been issued by the Department, to the extent applicable under COMAR 26.11.03.23.

13. MINOR PERMIT MODIFICATIONS

[COMAR 26.11.03.16]

The Permittee may apply to the Department to make a minor modification to the federally enforceable provisions of this Part 70 permit as provided in COMAR 26.11.03.16 and in accordance with the following conditions:

a. A minor permit modification is a Part 70 permit revision that:

(1) Does not result in a violation of any applicable requirement of the Clean Air Act;

(2) Does not significantly revise existing federally enforceable monitoring, including test methods, reporting, record keeping, or compliance certification requirements except by:

(a) Adding new requirements,

(b) Eliminating the requirements if they are rendered meaningless because the emissions to which the requirements apply will no longer occur, or

(c) Changing from one approved test method for a pollutant and source category to another;

(3) Does not require or modify a:

(a) Case-by-case determination of a federally enforceable emissions standard,

(b) Source specific determination for temporary sources of ambient impacts, or

(c) Visibility or increment analysis;

(4) Does not seek to establish or modify a federally enforceable permit term or condition for which there is no corresponding underlying applicable requirement of the Clean Air Act, but that the Permittee has assumed to avoid an applicable requirement to which the source would otherwise be subject, including:

(a) A federally enforceable emissions standard applied to the source pursuant to COMAR 26.11.02.03 to avoid classification as a Title I modification; and

(b) An alternative emissions standard applied to an emissions unit pursuant to regulations promulgated under Section 112(i)(5) of the Clean Air Act

(5) Is not a Title I modification; and

(6) Is not required under COMAR 26.11.03.17 to be processed as a significant modification to this Part 70 permit.

b. Application for a Minor Permit Modification

The Permittee shall submit to the Department an application for a minor permit modification that satisfies the requirements of COMAR 26.11.03.03 which includes the following:

(1) A description of the proposed change, the emissions resulting from the change, and any new applicable requirements that will apply if the change is made;

(2) The proposed minor permit modification;

(3) Certification by a responsible official, in accordance with COMAR 26.11.02.02F, that:

(a) The proposed change meets the criteria for a minor permit modification, and

(b) The Permittee has obtained or applied for all required permits-to-construct required by COMAR 26.11.03.16 with respect to the proposed change;

(4) Completed forms for the Department to use to notify the EPA and affected states, as required by COMAR 26.11.03.07-.12.

c. Permittee's Ability to Make Change

(1) For changes proposed as minor permit modifications to this permit that will require the applicant to obtain a permit to construct, the permit to construct must be issued prior to the new change.

(2) During the period of time after the Permittee applies for a minor modification but before the Department acts in accordance with COMAR 26.11.03.16F(2):

(a) The Permittee shall comply with applicable requirements of the Clean Air Act related to the change and the permit terms and conditions described in the application for the minor modification.

(b) The Permittee is not required to comply with the terms and conditions in the permit it seeks to modify. If the Permittee fails to comply with the terms and conditions in the application during this time, the terms and conditions of both this permit and the application for modification may be enforced against it.

d. The Permittee is subject to enforcement action if it is determined at any time that a change made under COMAR 26.11.03.16 is not within the scope of this regulation.

e. Minor permit modification procedures may be used for Part 70 permit modifications involving the use of economic incentives, marketable permits, emissions trading, and other similar approaches, but only to the extent that the minor permit modification procedures are explicitly provided for in regulations approved by the EPA as part of the Maryland SIP or in other applicable requirements of the Clean Air Act.

14. ADMINISTRATIVE PART 70 OPERATING PERMIT AMENDMENTS

[COMAR 26.11.03.15]

The Permittee may apply to the department to make an administrative permit amendment as provided in COMAR 26.11.03.15 and in accordance with the following conditions:

a. An application for an administrative permit amendment shall:

(1) Be in writing;

(2) Include a statement certified by a responsible official that the proposed amendment meets the criteria in COMAR 26.11.03.15 for an administrative permit amendment, and

(3) Identify those provisions of this part 70 permit for which the amendment is requested, including the basis for the request.

b. An administrative permit amendment:

(1) Is a correction of a typographical error;

(2) Identifies a change in the name, address, or phone number of a person identified in this permit, or a similar administrative change involving the Permittee or other matters which are not directly related to the control of air pollution;

(3) requires more frequent monitoring or reporting by the Permittee;

(4) Allows for a change in ownership or operational control of a source for which the Department determines that no other revision to the permit is necessary and is documented as per COMAR 26.11.03.15B(4);

(5) Incorporates into this permit the requirements from preconstruction review permits or approvals issued by the Department in accordance with COMAR 26.11.03.15B(5), but only if it satisfies 40 CFR 70.7(d)(1)(v);

(6) Incorporates any other type of change, as approved by the EPA, which is similar to those in COMAR 26.11.03.15B(1)—(4);

(7) Notwithstanding COMAR 26.11.03.15B(1)—(6), all modifications to acid rain control provisions included in this Part 70 permit are

governed by applicable requirements promulgated under Title IV of the Clean Air Act; or

(8) Incorporates any change to a term or condition specified as State-only enforceable, if the Permittee has obtained all necessary permits-to-construct and approvals that apply to the change.

c. The Permittee may make the change addressed in the application for an administrative amendment upon receipt by the Department of the application, if all permits-to-construct or approvals otherwise required by COMAR 26.11.02 prior to making the change have first been obtained from the Department.

d. The permit shield in COMAR 26.11.03.23 applies to administrative permit amendments made under Section B (5) of COMAR 26.11.03.15, but only after the Department takes final action to revise the permit.

e. The Permittee is subject to enforcement action if it is determined at any time that a change made under COMAR 26.11.03.15 is not within the scope of this regulation.

15. OFF-PERMIT CHANGES TO THIS SOURCE

[COMAR 26.11.03.19]

The Permittee may make off-permit changes to this facility as provided in COMAR 26.11.03.19 and in accordance with the following conditions:

a. The Permittee may make a change to this permitted facility that is not addressed or prohibited by the federally enforceable conditions of this Part 70 permit without obtaining a Part 70 permit revision if:

(1) The Permittee has obtained all permits and approvals required by COMAR 26.11.02 and .03;

(2) The change is not subject to any requirements under Title IV of the Clean Air Act;

(3) The change is not a Title I modification; and

(4) The change does not violate an applicable requirement of the Clean Air Act or a federally enforceable term or condition of the permit.

b. For a change that qualifies under COMAR 26.11.03.19, the Permittee shall provide contemporaneous written notice to the Department and the EPA, except for a change to an emissions unit or activity that is exempt from the Part 70 permit application, as provided in COMAR 26.11.03.04. This written notice shall describe the change, including the date it was made, any change in emissions, including the pollutants emitted, and any new applicable requirements of the Clean Air Act that apply as a result of the change.

c. Upon satisfying the requirements of COMAR 26.11.03.19, the Permittee may make the proposed change.

d. The Permittee shall keep a record describing:

(1) Changes made at the facility that result in emissions of a regulated air pollutant subject to an applicable requirement of the Clean Air Act , but not otherwise regulated under this permit; and

(2) The emissions resulting from those changes.

e. Changes that qualify under COMAR 26.11.03.19 are not subject to the requirements for Part 70 revisions.

f. The Permittee shall include each off-permit change under COMAR 26.11.03.19 in the application for renewal of the part 70 permit.

g. The permit shield in COMAR 26.11.03.23 does not apply to off-permit changes made under COMAR 26.11.03.19.

h. The Permittee is subject to enforcement action if it is determined that an off-permit change made under COMAR 26.11.03.19 is not within the scope of this regulation.

16. ON-PERMIT CHANGES TO SOURCES

[COMAR 26.11.03.18]

The Permittee may make on-permit changes that are allowed under Section 502(b) (10) of the Clean Air Act as provided in COMAR 26.11.03.18 and in accordance with the following conditions:

a. The Permittee may make a change to this facility without obtaining a revision to this Part 70 permit if:

(1) The change is not a Title I modification;

(2) The change does not result in emissions in excess of those expressly allowed under the federally enforceable provisions of the Part 70 permit for the permitted facility or for an emissions unit within the facility, whether expressed as a rate of emissions or in terms of total emissions;

(3) The Permittee has obtained all permits and approvals required by COMAR 26.11.02 and .03;

(4) The change does not violate an applicable requirement of the Clean Air Act;

(5) The change does not violate a federally enforceable permit term or condition related to monitoring, including test methods, record keeping, reporting, or compliance certification requirements;

(6) The change does not violate a federally enforceable permit term or condition limiting hours of operation, work practices, fuel usage, raw material usage, or production levels if the term or condition has been established to limit emissions allowable under this permit;

(7) If applicable, the change does not modify a federally enforceable provision of a compliance plan or schedule in this Part 70 permit unless the Department has approved the change in writing; and

(8) This permit does not expressly prohibit the change under COMAR 26.11.03.18.

b. The Permittee shall notify the Department and the EPA in writing of a proposed on-permit change under COMAR 26.11.03.18 not later than 7 days before the change is made. The written information shall include the following information:

(1) A description of the proposed change;

(2) The date on which the change is proposed to be made;

(3) Any change in emissions resulting from the change, including the pollutants emitted;

(4) Any new applicable requirement of the Clean Air Act; and

(5) Any permit term or condition that would no longer apply.

c. The responsible official of this facility shall certify in accordance with COMAR 26.11.02.02F that the proposed change meets the criteria for the use of on-permit changes under COMAR 26.11.03.18.

d. The Permittee shall attach a copy of each notice required by condition b. above to this Part 70 permit.

e. On-permit changes that qualify under COMAR 26.11.03.18 are not subject to the requirements for part 70 permit revisions.

f. Upon satisfying the requirements under COMAR 26.11.03.18, the Permittee may make the proposed change.

g. The permit shield in COMAR 26.11.03.23 does not apply to on-permit changes under COMAR 26.11.03.18.

h. The Permittee is subject to enforcement action if it is determined that an on-permit change made under COMAR 26.11.03.18 is not within the scope of the regulation or violates any requirement of the State air pollution control law.

17. FEE PAYMENT

[COMAR 26.11.02.16A (2) & (5) (b)]

a. The fee for this Part 70 permit is as prescribed in Regulation .19 of COMAR 26.11.02.

b. The fee is due on and shall be paid on or before each 12-month anniversary date of the permit.

c. Failure to pay the annual permit fee constitutes cause for revocation of the permit by the Department.

18. REQUIREMENTS FOR PERMITS-TO-CONSTRUCT AND APPROVALS

[COMAR 26.11.02.09.]

The Permittee may not construct or modify or cause to be constructed or modified any of the following sources without first obtaining, and having in current effect, the specified permits-to-construct and approvals:

a. New Source Review source, as defined in COMAR 26.11.01.01, approval required, except for generating stations constructed by electric companies;

b. Prevention of Significant Deterioration source, as defined in COMAR 26.11.01.01, approval required, except for generating stations constructed by electric companies;

c. New Source Performance Standard source, as defined in COMAR 26.11.01.01, permit to construct required, except for generating stations constructed by electric companies;

d. National Emission Standards for Hazardous Air Pollutants source, as defined in COMAR 26.11.01.01, permit to construct required, except for generating stations constructed by electric companies;

e. A stationary source of lead that discharges one ton per year or more of lead or lead compounds measured as elemental lead, permit to construct required, except for generating stations constructed by electric companies;

f. All stationary sources of air pollution, including installations and air pollution control equipment, except as listed in COMAR 26.11.02.10, permit to construct required;

g. In the event of a conflict between the applicability of (a. — e.) above and an exemption listed in COMAR 26.11.02.10, the provision that requires a permit applies.

h. Approval of a PSD or NSR source by the Department does not relieve the Permittee obtaining an approval from also obtaining all permits-to-construct required by (c. — g.) above.

19. CONSOLIDATION OF PROCEDURES FOR PUBLIC PARTICIPATION

[COMAR 26.11.02.11C] and [COMAR 26.11.03.01K]

The Permittee may request the Department to authorize special procedures for the Permittee to apply simultaneously, to the extent possible, for a permit to construct and a revision to this permit.

These procedures may provide for combined public notices, informational meetings, and public hearings for both permits but shall not adversely affect the rights of a person, including EPA and affected states, to obtain information about the application for a permit, to comment on an application, or to challenge a permit that is issued.

These procedures shall not alter any existing permit procedures or time frames.

20. PROPERTY RIGHTS

[COMAR 26.11.03.06E (4)]

This Part 70 permit does not convey any property rights of any sort, or any exclusive privileges.

21. SEVERABILITY

[COMAR 26.11.03.06A (5)]

If any portion of this Part 70 permit is challenged, or any term or condition deemed unenforceable, the remainder of the requirements of the permit continues to be valid.

22. INSPECTION AND ENTRY

[COMAR 26.11.03.06G (3)]

The Permittee shall allow employees and authorized representatives of the Department, the EPA, and local environmental health agencies, upon presentation of credentials or other documents as may be required by law, to:

a. Enter at a reasonable time without delay and without prior notification the Permittee's property where a Part 70 source is located, emissions-related activity is conducted, or records required by this permit are kept;

b. Have access to and make copies of records required by the permit;

c. Inspect all emissions units within the facility subject to the permit and all related monitoring systems, air pollution control equipment, and practices or operations regulated or required by the permit; and

d. Sample or monitor any substances or parameters at or related to the emissions units at the facility for the purpose of determining compliance with the permit.

23. DUTY TO PROVIDE INFORMATION

[COMAR 26.11.03.06E (5)]

The Permittee shall furnish to the Department, within a reasonable time specified by the Department, information requested in writing by the Department in order to determine whether the Permittee is in compliance with the federally enforceable conditions of this Part 70 permit, or whether cause exists for revising or revoking the permit. Upon request, the Permittee shall also furnish to the Department records required to be kept under the permit.

For information claimed by the Permittee to be confidential and therefore potentially not discloseable to the public, the Department may require the Permittee to provide a copy of the records directly to the EPA along with a claim of confidentiality.

The Permittee shall also furnish to the Department, within a reasonable time specified by the Department, information or records requested in writing by the Department in order to determine if the Permittee is in compliance with the State-only enforceable conditions of this permit.

24. COMPLIANCE REQUIREMENTS

[COMAR 26.11.03.06E (1)] and [COMAR 26.11.03.06A (11)] and [COMAR 26.11.02.05]

The Permittee shall comply with the conditions of this Part 70 permit. Noncompliance with the permit constitutes a violation of the Clean Air Act,

and/or the Environment Article Title 2 of the Annotated Code of Maryland and may subject the Permittee to:

a. Enforcement action,

b. Permit revocation or revision,

c. Denial of the renewal of a Part 70 permit, or

d. Any combination of these actions.

The conditions in this Part 70 permit are enforceable by EPA and citizens under the Clean Air Act except for the State-only enforceable conditions.

Under Environment Article Section 2-609, Annotated Code of Maryland, the Department may seek immediate injunctive relief against a person who violates this permit in such a manner as to cause a threat to human health or the environment.

25. CREDIBLE EVIDENCE

Nothing in this permit shall be interpreted to preclude the use of credible evidence to demonstrate noncompliance with any term of this permit.

26. NEED TO HALT OR REDUCE ACTIVITY NOT A DEFENSE

[COMAR 26.11.03.06E (2)]

The need to halt or reduce activity in order to comply with the conditions of this permit may not be used as a defense in an enforcement action.

27. CIRCUMVENTION

[COMAR 26.11.01.06]

The Permittee may not install or use any article, machine, equipment or other contrivance, the use of which, without resulting in a reduction in the total weight of emissions, conceals or dilutes emissions which would otherwise constitute a violation of any applicable air pollution control regulation.

28. PERMIT SHIELD

[COMAR 26.11.03.23]

A permit shield as described in COMAR 26.11.03.23 shall apply only to terms and conditions in this Part 70 permit that have been specifically identified as covered by the permit shield. Neither this permit nor COMAR 26.11.03.23 alters the following:

a. The emergency order provisions in Section 303 of the Clean Air Act, including the authority of EPA under that section;

b. The liability of the Permittee for a violation of an applicable requirement of the Clean Air Act before or when this permit is issued or for a violation that continues after issuance;

c. The requirements of the Acid Rain Program, consistent with Section 408(a) of the Clean Air Act;

d. The ability of the Department or EPA to obtain information from a source pursuant to Maryland law and Section 114 of the Clean Air Act; or

e. The authority of the Department to enforce an applicable requirement of the State air pollution control law that is not an applicable requirement of the Clean Air Act.

29. ALTERNATE OPERATING SCENARIOS

[COMAR 26.11.03.06A (9)]

For all alternate operating scenarios approved by the Department and contained within this permit, the Permittee, while changing from one approved scenario to another, shall contemporaneously record in a log maintained at the facility each scenario under which the emissions unit is operating and the date and time the scenario started and ended.

SECTION III PLANT WIDE CONDITIONS

1. PARTICULATE MATTER FROM CONSTRUCTION AND DEMOLITION

[COMAR 26.11.06.03D]

The Permittee shall not cause or permit any building, its appurtenances, or a road to be used, constructed, altered, repaired, or demolished without taking reasonable precautions to prevent particulate matter from becoming airborne.

2. OPEN BURNING

[COMAR 26.11.07]

Except as provided in COMAR 26.11.07.04, the Permittee shall not cause or permit an open fire from June 1 through August 31 of any calendar year. Prior to any open burning, the Permittee shall request and receive approval from the Department.

3. AIR POLLUTION EPISODE

[COMAR 26.11.05.04]

When requested by the Department, the Permittee shall prepare in writing standby emissions reduction plans, consistent with good industrial practice and safe operating procedures, for reducing emissions creating air pollution during periods of Alert, Warning, and Emergency of an air pollution episode.

4. REPORT OF EXCESS EMISSIONS AND DEVIATIONS

[COMAR 26.11.01.07] and [COMAR 26.11.03.06C (7)]

The Permittee shall comply with the following conditions for occurrences of excess emissions and deviations from requirements of this permit, including those in Section VI – State-only Enforceable Conditions:

a. Report any deviation from permit requirements that could endanger human health or the environment, by orally notifying the Department immediately upon discovery of the deviation;

b. Promptly report all occurrences of excess emissions that are expected to last for one hour or longer by orally notifying the Department of the onset and termination of the occurrence;

c. When requested by the Department the Permittee shall report all deviations from permit conditions, including those attributed to malfunctions as defined in COMAR 26.11.01.07A, within 5 days of the request by submitting a written description of the deviation to the Department. The written report shall include the cause, dates and times of the onset and termination of the deviation, and an account of all actions planned or taken to reduce, eliminate, and prevent recurrence of the deviation;

d. The Permittee shall submit to the Department semi-annual monitoring reports that confirm that all required monitoring was performed, and that provide accounts of all deviations from permit requirements that occurred during the reporting periods. Reporting periods shall be January 1 through June 30 and July 1 through December 31, and reports shall be submitted within 30 days of the end of each reporting period. Each account of deviation shall include a description of the deviation, the dates and times of onset and termination, identification of the person who observed or discovered the deviation, causes and corrective actions taken, and actions taken to prevent recurrence. If no deviations from permit conditions occurred during a reporting period, the Permittee shall submit a written report that so states.

e. When requested by the Department, the Permittee shall submit a written report to the Department within 10 days of receiving the request concerning an occurrence of excess emissions. The report shall contain the information required in COMAR 26.11.01.07D (2).

5. ACCIDENTAL RELEASE PROVISIONS

[COMAR 26.11.03.03B (23)] and [40 CFR 68]

Should the Permittee become subject to 40 CFR 68 during the term of this permit, the Permittee shall submit risk management plans by the date specified in 40 CFR 68.150 and shall certify compliance with the requirements of 40 CFR 68 as part of the annual compliance certification as required by 40 CFR 70.

The Permittee shall initiate a permit revision or reopening according to the procedures of 40 CFR 70.7 to incorporate appropriate permit conditions into the Permittee's Part 70 permit.

6. GENERAL TESTING REQUIREMENTS

[COMAR 26.11.01.04]

The Department may require the Permittee to conduct, or have conducted, testing to determine compliance with this Part 70 permit. The Department, at its option, may witness or conduct these tests. This testing shall be done at a reasonable time, and all information gathered during a testing operation shall be provided to the Department.

7. EMISSIONS TEST METHODS

[COMAR 26.11.01.04]

Compliance with the emissions standards and limitations in this Part 70 permit shall be determined by the test methods designated and described below or other test methods submitted to and approved by the Department.

Reference documents of the test methods approved by the Department include the following:

a. 40 CFR 60, appendix A

b. 40 CFR 51, appendix M

c. The Department's Technical Memorandum 91-01 "Test Methods and Equipment Specifications for Stationary Sources", (January 1991), as amended through Supplement 3, (October 1, 1997)

8. EMISSIONS CERTIFICATION REPORT

[COMAR 26.11.01.05-1] and [COMAR 26.11.02.19C] and [COMAR 26.11.02.19D]

The Permittee shall certify actual annual emissions of regulated pollutants from the facility on a calendar year basis.

a. The certification shall be on forms obtained from the Department and submitted to the Department not later than April 1 of the year following the year for which the certification is required;

b. The individual making the certification shall certify that the information is accurate to the individual's best knowledge. The individual shall be:

(1) Familiar with each source for which the certifications forms are submitted, and

(2) Responsible for the accuracy of the emissions information;

c. The Permittee shall maintain records necessary to support the emissions certification including the following information if applicable:

(1) The total amount of actual emissions of each regulated pollutant and the total of all regulated pollutants;

(2) An explanation of the methods used to quantify the emissions and the operating schedules and production data that were used to determine emissions, including significant assumptions made;

(3) Amounts, types and analyses of all fuels used;

(4) Emissions data from continuous emissions monitors that are required by this permit, including monitor calibration and malfunction information;

(5) Identification, description, and use records of all air pollution control equipment and compliance monitoring equipment including:

(a) Significant maintenance performed,
(b) Malfunctions and downtime, and
(c) Episodes of reduced efficiency of all equipment;

(6) Limitations on source operation or any work practice standards that significantly affect emissions; and

(7) Other relevant information as required by the Department.

9. COMPLIANCE CERTIFICATION REPORT

[COMAR 26.11.03.06G (6) and (7)]

The Permittee shall submit to the Department and EPA Region III a report certifying compliance with each term of this Part 70 permit including each applicable standard, emissions limitation, and work practice for the previous calendar year by April 1 of each year.

a. The compliance certification shall include:

(1) The identification of each term or condition of this permit which is the basis of the certification;

(2) The compliance status;

(3) Whether the compliance was continuous or intermittent;

(4) The methods used for determining the compliance status of each source, currently and over the reporting period; and

(5) Any other information required to be reported to the Department that is necessary to determine the compliance status of the Permittee with this permit.

b. The Permittee shall submit the compliance certification reports to the Department and EPA simultaneously.

10. CERTIFICATION BY RESPONSIBLE OFFICIAL

[COMAR 26.11.02.02F]

All application forms, reports, and compliance certifications submitted pursuant to this permit shall be certified by a responsible official as to truth, accuracy, and completeness. The Permittee shall expeditiously notify the Department of an appointment of a new responsible official.

The certification shall be in the following form:

"I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information

submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations."

11. SAMPLING AND EMISSIONS TESTING RECORD KEEPING

[COMAR 26.11.03.06C (5)]

The Permittee shall gather and retain the following information when sampling and testing for compliance demonstrations:

a. The location as specified in this permit, and the date and time that samples and measurements are taken;

b. All pertinent operating conditions existing at the time that samples and measurements are taken;

c. The date that each analysis of a sample or emissions test is performed and the name of the person taking the sample or performing the emissions test;

d. The identity of the Permittee, individual, or other entity that performed the analysis;

e. The analytical techniques and methods used; and

f. The results of each analysis.

12. GENERAL RECORDKEEPING

[COMAR 26.11.03.06C (6)]

The Permittee shall retain records of all monitoring data and information that support the compliance certification for a period of five (5) years from the date that the monitoring, sample measurement, application, report or emissions test was completed or submitted to the Department.

These records and support information shall include:

a. All calibration and maintenance records;

b. All original data collected from continuous monitoring instrumentation;

c. Records which support the annual emissions certification; and

d. Copies of all reports required by this permit.

13. GENERAL CONFORMITY – Not Applicable

[COMAR 26.11.26.09]

The Permittee shall comply with the general conformity requirements of 40 CFR 93, Subpart B and COMAR 26.11.26.09.

14. ASBESTOS PROVISIONS – Not Applicable

[40 CFR 61, Subpart M]

The Permittee shall comply with 40 CFR 61, Subpart M when conducting any renovation or demolition activities at the facility.

15. OZONE DEPLETING REGULATIONS

[40 CFR 82, Subpart F]

The Permittee shall comply with the standards for recycling and emissions reduction pursuant to 40 CFR 82, Subpart F, except as provided for MVACs in subpart B:

a. Persons opening appliances for maintenance, service, repair, or disposal shall comply with the prohibitions and required practices pursuant to 40 CFR 82.154 and 82.156.

b. Equipment used during the maintenance, service, repair or disposal of appliances shall comply with the standards for recycling and recovery equipment pursuant to 40 CFR 82.158.

c. Persons performing maintenance, service, repairs or disposal of appliances shall be certified by an approved technician certification program pursuant to 40 CFR 82.161.

d. Persons performing maintenance, service, repairs or disposal of appliances shall certify with the Administrator pursuant to 40 CFR 82.162.

e. Persons disposing of small appliances, MVACS, and MVAC-like appliances as defined in 40 CFR 82.152, shall comply with record keeping requirements pursuant to 40 CFR 82.166.

f. Persons owning commercial or industrial process refrigeration equipment shall comply with the leak repair requirements pursuant to 40 CFR 82.156.

g. Owners/operators of appliances normally containing 50 or more pounds of refrigerant shall keep records of refrigerant purchased and added to such appliances pursuant to 40 CFR 82.166.

16. ACID RAIN PERMIT

The facility is an affected source under the 1990 CAAA, Title IV Acid Rain Program and must comply with the renewal Acid Rain Permit being issued in conjunction with this permit. See Appendix A.

SECTION IV PLANT-SPECIFIC CONDITIONS

This section provides tables that include the emissions standards, emissions limitations, and work practices applicable to each emissions unit located at this facility. The Permittee shall comply with all applicable emissions standards, emissions limitations and work practices included herein.

The tables also include testing, monitoring, record keeping and reporting requirements specific to each emissions unit. In addition to the requirements included here in **Section IV**, the Permittee is also subject to the general testing, monitoring, record keeping and reporting requirements included in **Section III – Plant Wide Conditions** of this permit.

Unless otherwise provided in the specific requirements for an emissions unit, the Permittee shall maintain at the facility for at least five (5) years, and shall make available to the Department upon request, all records that the Permittee is required under this section to establish. [Authority: COMAR 26.11.03.06C (5) (g)]

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1.0	**Emissions Unit:** EU-1 and EU-2 Combined cycle electric generating units consisting of two GE Frame 7EA combustion turbines (CTs) rated at 84 MW each; two (2) unfired HRSGs; and one (1) SG rated at 80 MW for a total generating electric capacity of 248 MW. The primary fuel is natural gas. Ultra low-sulfur diesel fuel oil is used as a back-up fuel.
1.1	**Applicable Standards/Limits:** Control of Visible Emissions A. **COMAR 26.11.09.05A (2*)* -** Visible Emissions. "In Areas III and IV, a person may not cause or permit the discharge of emissions from any fuel burning equipment, other than water in an uncombined form, which is visible to human observers." Exceptions. "Section A (1) and (2) does not apply to emissions during load changing, soot blowing, startup, Black Start Events or occasional cleaning of control equipment if: (a) The visible emissions are not greater than 40 percent opacity; and (b) The visible emissions do not occur for more than 6 consecutive minutes in any sixty minute period." Control of Sulfur Dioxide and Sulfuric Acid Mist Emissions B1. **CPCN Case No. 9341 Air Quality Section, Condition No. 8**, which limits the sulfur content in ULSD fuel oil to 0.0015 wt %.

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B2. **CPCN Case No. 9341, Air Quality Section, Condition No. 5,** which limits sulfur dioxide emissions from each combustion turbine to the limits shown below, as hourly emissions expressed in pounds per hour, except during periods of start-up, shut-down, malfunction, and Black Start Events:

	Natural Gas	LNG	ULSD Fuel Oil
Sulfur Oxides (as SO_2)	29	29	54

B3. **CPCN Case No. 9341, Air Quality Section, Condition No. 5,** which limits sulfuric acid mist from each combustion turbine to the limits shown below, as hourly emissions expressed in pounds per hour, except during periods of start-up, shut-down, malfunction, and Black Start Events:

	Natural Gas	LNG	ULSD Fuel Oil
Sulfuric Acid Mist	3	3	6

B4. **NSPS Limitation - 40 CFR 60.333 - Subpart GG,** which limits sulfur content in any fuel burned in a gas turbine to 0.8 wt. %.

B5. **Phase II Acid Rain Requirement**
The Permittee shall comply with the provisions and all applicable requirements of the Phase II Acid Rain program. See Appendix A for the renewal Acid Rain Permit.

B6. **Cross-State Air Pollution Rule**

TR SO_2 Group 1 Trading Program 40 CFR Part 97 Subpart CCCCC
The Permittee shall comply with the provisions and requirements of §97.601 through §97.635

Note: §97.606(c) SO2 emissions requirements. For TR SO_2 Group 1 emissions limitation: As of the allowance transfer deadline for a control period in a given year, the owners and operators of each TR SO_2 Group 1 source and each TR SO_2 Group 1 unit at the source shall hold, in the source's compliance account, TR SO_2 Group 1 allowances available for deduction for such control period under §97.624(a) in an amount not less than the tons of total SO_2 emissions for such control period from all TR SO_2 Group 1 units at the source.

Allowance transfer deadline means, for a control period in a given year, midnight of March 1 (if it is a business day), or midnight of the first business day thereafter (if March 1 is not a business day), immediately after such control period and is the deadline by which a TR SO_2 Group 1 allowance transfer must be submitted for recordation in a TR SO_2 Group 1 source's compliance account in order to be available for use in complying with the source's TR SO_2 Group 1 emissions

Table IV – 1

limitation for such control period in accordance with §§97.606 and 97.624.

Control of Nitrogen Oxides Emissions

PSD Limitations

C1. **CPCN No. 9341 Air Quality Section, Condition No. 4**, which limits nitrogen oxides (NOx) emissions for each turbine, except during start-up period, shut-down, malfunction, and Black Start Events when burning natural gas, ULSD fuel oil, or LNG, as follows:

(a) Natural gas: the outlet concentration of NOx shall not exceed 9 parts per million by volume on a dry basis (ppmvd) at 15 percent excess oxygen on an hourly basis.

(b) ULSD fuel oil: the outlet concentration of NOx shall not exceed 54 ppmvd at 15 percent excess oxygen on an hourly basis.

(c) LNG: the outlet concentration of NOx shall not exceed 10 ppmvd at 15 percent excess oxygen on an hourly basis.

C2. **CPCN Case No. 9341, Air Quality Section, Condition No. 5.**
Each combustion turbine, except during start-up period, shut-down, malfunction, and during Black Start Events, shall be limited to no more than the following hourly emissions expressed in units of pounds per hour:

	Natural Gas	LNG	ULSD Fuel Oil
Nitrogen Oxides (as NO_2)	35	39	239

C3. **CPCN Case No. 9341, Air Quality Section, Condition No. 6.**
Annual facility-wide NO_x emissions shall be limited to no more than 437 tons per year (as NO_2), excluding emissions during periods of start-up, shutdown, malfunction or PJM system emergency or Black Start Events as defined in Condition No. 11of the CPCN. Under no circumstance shall facility-wide emissions exceed 518 tons per year

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NSPS Limitations

C4. **40 CFR 60.332** - NSPS Subpart GG, which limits NOx emissions for each turbine when burning natural gas, ULSD Fuel oil, and LNG as derived by the following formula:

STD = 0.0075 (14.4/Y) + F
Where:

STD = Allowable NOx emissions (percent by volume at 15 percent oxygen and on dry basis).
Y = Manufacturer 's rated heat rate at manufacturer's rated load (kilojoules per watt hour (kj/wh) or, actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kj/wh.
F = NOx emissions allowance for fuel bound nitrogen as defined in paragraph (a) (4) of 40 CFR 60.332.

The value of Y (for the combustion turbines) used with the above formula is 11.160 kj/kwh while the weight percent of the fuel bound nitrogen used in deriving the value of F for: natural gas is 0.21 percent; LNG is 0.21 percent; and ULSD fuel oil is 0.021 percent.

Calculated NSPS NOx emissions limit for each turbine using the respective fuels are as follows:

(a) Nat gas: the outlet concentration of NOx shall not exceed 144 parts per million by volume on a dry basis (ppmvd) at 15 percent excess oxygen on an hourly basis.

(b) ULSD fuel oil: the outlet concentration of NOx shall not exceed 101 parts per million by volume on a dry basis (ppmvd) at 15 percent excess oxygen on an hourly basis.

(c) LNG: the outlet concentration of NOx shall not exceed 144 parts per million by volume on a dry basis (ppmvd) at 15 percent excess oxygen on an hourly basis.

C5. **NOx RACT Limitation**

COMAR 26.11.09.08G (2), which requires the owner or Permittee of combustion turbines with a capacity factor greater than 15 percent to meet an hourly average NOx emission rate as follows: not more than 42 ppm when burning gas; 65 ppm when burning fuel oil (dry volume at 15 percent oxygen) or meet applicable

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Prevention of Significant Deterioration limits, whichever is more restrictive. (Note that the PSD limit is more restrictive.)

C6. **Cross-State Air Pollution Rule**

TR NOx Annual Trading Program 40 CFR Part 97 Subpart AAAAA
The Permittee shall comply with the provisions and requirements of §97.401 through §97.435

Note: §97.406(c) NOx emissions requirements. For TR NOx Annual emissions limitation: As of the allowance transfer deadline for a control period in a given year, the owners and operators of each TR NOx Annual source and each TR NOx Annual unit at the source shall hold, in the source's compliance account, TR NOx Annual allowances available for deduction for such control period under §97.424(a) in an amount not less than the tons of total NOx emissions for such control period from all TR NOx Annual units at the source.

Allowance transfer deadline means, for a control period in a given year, midnight of March 1 (if it is a business day), or midnight of the first business day thereafter (if March 1 is not a business day), immediately after such control period and is the deadline by which a TR NOx Annual allowance transfer must be submitted for recordation in a TR NOx Annual source's compliance account in order to be available for use in complying with the source's TR NOx Annual emissions limitation for such control period in accordance with §§97.406 and 97.424.

TR NOx Ozone Season Trading Program 40 CFR Part 97 Subpart BBBBB
The Permittee shall comply with the provisions and requirements of §97.501 through §97.535

Note: §97.506(c) NOx emissions requirements. For TR NOx Ozone Season emissions limitation: As of the allowance transfer deadline for a control period in a given year, the owners and operators of each TR NOx Ozone Season source and each TR NOx Ozone Season unit at the source shall hold, in the source's compliance account, TR NOx Ozone Season allowances available for deduction for such control period under §97.524(a) in an amount not less than the tons of total NOx emissions for such control period from all TR NOx Ozone Season units at the source.

Allowance transfer deadline means, for a control period in a given year, midnight of December 1 (if it is a business day), or midnight of the first business day thereafter (if December 1 is not a business day), immediately after such control period and is the deadline by which a TR NOx Ozone Season allowance transfer must be submitted for recordation in a TR NOx Ozone Season source's compliance account in order to be available for use in complying with the source's TR NOx Ozone Season emissions limitation for such control period in accordance with §§97.506 and 97.524.

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Control of Carbon Monoxide Emissions

D. **CPCN No.9341 Air Quality Section, Condition No. 5.**
Each combustion turbine, except during start-up period, shut-down, malfunction, and Black Start Events, shall be limited to no more than the following hourly emissions expressed in units of pounds per hours:

	Natural Gas	LNG	ULSD Fuel Oil
Carbon Monoxide	59	59	71

Control of Volatile Organic Compounds

E. **CPCN No.9341 Air Quality Section, Condition No. 5.**
Each combustion turbine, except during start-up period, shut-down, malfunction, and Events, shall be limited to no more than the following hourly emissions expressed in units of pounds per hours:

	Natural Gas	LNG	ULSD Fuel Oil
Volatile Organic Compounds	2	2	5

Control of Particulate Matter Emissions

F. **CPCN No. 9341 Air Quality Section, Condition No. 5**.
Each combustion turbine, except during start-up period, shut-down, malfunction, and Events, shall be limited to no more than the following hourly emissions expressed in units of pounds per hours:

	Natural Gas	LNG	ULSD Fuel Oil
PM_{10}	7	7	15
Total d Particulate	7	7	15

Operational Limitation

G1. **CPCN Case No. 9341, Air Quality Section, Condition No. 9**
The combustion turbines shall generate electricity using only natural gas or LNG except as otherwise provided for in these conditions:

(a) When the fuel delivery to the turbines is interrupted or curtailed, the facility may burn ULSD fuel oil but shall be limited to 143 tons of NO_x per year, when burning ULSD fuel oil;

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(b) If the facility has reached its 143 ton limit and there is a PJM system emergency as defined in Condition No. 11 and natural gas is unavailable, or there is Black Start event and natural gas is unavailable, the facility may burn ULSD fuel oil; and

(c) Under no circumstance, however, may the facility burn ULSD fuel oil for more than 2,400 turbine hours per year.

For the purposes of this condition, a year is defined as November 1 through October 31. Natural gas/LNG service interruptions shall be verified by a letter each year from Brandywine's natural gas/LNG supplier identifying the dates on which service was restricted. Brandywine will ensure that the Department receives a copy of this letter within 60 days of the start of each new year. [**Reference: CPCN No. 9341 condition 9, Air Quality Section**].

G2. **CPCN Case No. 9341, Air Quality Section, Condition No. 11.**

For the purposes of Conditions Nos. 6 and 9 of the CPCN, a PJM system emergency is operation during reserve shortages and refers to Maximum Generation Emergency, as defined in Section 2.0 of PJM Manual 35: Definitions and Acronyms, Revision 22 Effective date 2/28/2013.

G3. **CPCN Case No. 9341, Air Quality Section, Condition No. 7.**

Except for start-up and shutdown periods, and except during Black Start Events, each combustion turbine unit shall operate only when the unit, for natural gas or LNG firing, is in DLN premix mode, or when firing ULSD fuel oil, water injection is engaged. [**Reference: CPCN No.9341, Air Quality Section**].

Note that after the initiation of premix steady state while firing natural gas or LNG and upon initiation of water injection while firing ULSD fuel oil, an emissions monitoring stabilization period of up to 17 minutes is required to accommodate exhaust gas transit time from the exit of the combustion system to the CEMS.

1.2 **Testing Requirements:**

A. Visible Emissions Limitation
See monitoring requirements.

B. Sulfur Oxide and Sulfuric Acid Mist Emissions
The Permittee shall comply with the CPCN requirements by performing sampling and analysis of the "as fired" ULSD fuel oil to determine the percentage of sulfur by weight in the ULSD fuel oil as prescribed in 40 CFR 75 Appendix D [**Reference: CPCN No. 9341, Conditions No. 5 and No. 8, Air Quality Section**].

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	The Permittee shall perform QA/QC procedures for the SO_2 monitoring system in accordance with 40 CFR Part 75 Appendix D. [**Reference: CPCN No. 9341, Conditions No. 5 and No. 8, NSPS 40 CFR 60.334(h), and Acid Rain 40 CFR Part 75.21].** C. Nitrogen Oxide Emissions The Permittee shall perform QA/QC procedures for the NOx monitoring system in accordance with 40 CFR Part 75 Appendix D. [**Reference: CPCN No. 9341, Condition 8, NSPS 40 CFR 60.334(h), COMAR 26.11.09.08B(2)(c) and Acid Rain 40 CFR Part 75.70(e)].** D. Carbon Monoxide Emissions See monitoring requirements. E **Volatile Organic Compound** See monitoring requirements. F. **Particulate Matter Emissions** See monitoring requirements. G. **Operational Limitation** See record keeping requirements.
1.3	**Monitoring Requirements:** A. Visible Emissions Limitation The Permittee shall: (a) Properly operate and maintain the combustion turbines; (b) Maintain an operations manual and preventive maintenance plan; and (c) Verify no visible emissions when burning ULSD fuel oil. An observer shall perform at least one EPA Reference Method 9 observation of stack emissions for a 6 minute period once for each 168 hours that each of the combustion turbines burns ULSD fuel oil. If a turbine operates on ULSD fuel oil for less than 168 hours in a year, this observation requirement is waived for that calendar year. The Permittee shall perform the following if visible emissions are observed: (a) Inspect combustion turbine operations; (b) Perform all necessary adjustments and/or repairs to the turbines within 48 hours that visible emissions are eliminated; (c) Document in writing the results of the inspections, adjustments and/or repairs to the turbines; and (d) If the required adjustments and/or repairs have not eliminated the visible emissions within the stipulated 48 hours, perform a Method 9 observation

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once daily for 18 minutes until corrective action has eliminated the visible emissions. [**Reference: COMAR 26.11.03.06C**].

B. Sulfur Oxide and Sulfuric Acid Mist Emissions

CPCN

The Permittee shall perform sampling and analysis of the "as fired" sulfur content of the ULSD fuel oil to determine the percentage of sulfur by weight in the ULSD fuel oil. The sampling procedures shall follow the requirements of CPCN No. 9341, Conditions # 5 and # 8 as prescribed in 40 CFR 75 Appendix D, Sec. 2.2. [**Reference: CPCN No. 9341, Condition Nos. 5 and 8, Air Quality Section**].

NSPS Subpart GG - Monitoring Requirements

Natural Gas

Notwithstanding the provisions of paragraph (h) (1) of this section, the Permittee may elect not to monitor the total sulfur content of the gaseous fuel combusted in the turbine, if the gaseous fuel is demonstrated to meet the definition of natural gas in §60.331(u), regardless of whether an existing custom schedule approved by the administrator for subpart GG requires such monitoring. The owner or operator shall use one of the following sources of information to make the required demonstration.

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

b. Representative fuel sampling data, which show that the sulfur content of the gaseous fuel does not exceed 20-grains/100 scf. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of appendix D to Part 75 of this chapter is required. **[Reference: 40 CFR 60.334(h)(3)(i) and (ii)].**

ULSD Fuel Oil

The frequency of determining the sulfur (and nitrogen) content of the ULSD fuel oil is as follows:
Use one of the total sampling options and associated sampling frequency described in sections 2.2.3, 2.2.4.1, 2.2.4.2, and 2.2.2.4.3 of appendix D to part 75 of this chapter (i.e., flow proportional sampling, daily sampling, sampling from the unit's storage tank after each addition of the fuel to the tank, or sampling each delivery prior to combining it with ULSD fuel oil already in the intended storage tank **[Reference: 40 CFR 60.334(i)(1)]**.

Cross-State Air Pollution Rule

The Permittee shall comply with the monitoring requirements found in §97.606, §97.630, §97.631, §97.632, and §97.633.

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C. Nitrogen Oxide Emissions

CPCN

The Permittee shall operate and maintain a CEMS to monitor the NOx emissions. [**Reference: CPCN No. 9341, Air Quality Section, Condition No. 13**].

NSPS Subpart GG (40 CFR 60.334(a))

Except as provided in paragraph (b) of this section, the Permittee who owns a stationary gas turbine subject to the provisions of this subpart and uses water or steam injection to control NO_X emissions shall install, calibrate, maintain and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine [**Reference: 40 CFR 60.334(a)**].

NSPS Subpart GG (40 CFR 60.334 (b))

The owner or operator of any stationary gas turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and which uses water or steam injection to control NO_X emissions may, as an alternative to operating the continuous monitoring system described in paragraph (**a**) of this section, install, certify, maintain, operate, and quality-assure a continuous emission monitoring system (CEMS) consisting of NO_X and O_2 monitors. If the option to use a CEMS is chosen, the CEMS shall be installed, certified, maintained and operated as follows:

Each CEMS must be installed and certified according to PS 2 and 3 (for diluent) of 40 CFR part 60, appendix B, except that the 7-day calibration drift is based on unit operating days, not calendar days. Appendix F, Procedure 1 is not required. The relative accuracy test audit (RATA) of the NO_X and diluent monitors may be performed individually or on a combined basis, *i.e.*, the relative accuracy tests of the CEMS may be performed either:

(i) On a ppm basis (for NO_X) and a percent O_2 basis for oxygen; or
(ii) On a ppm at 15 percent O_2 basis; or
(iii)On a ppm basis (for NO_X) and a percent CO_2 basis (for a CO_2 monitor that uses the procedures in Method 20 to correct the NO_X data to 15 percent O_2).

[**Reference: 40 CFR 60.334(b)**].

NOx RACT

The Permittee shall use the data collected from the NOx CEM to demonstrate compliance with the RACT limitation [**Reference: COMAR 26.11.09.08B(2)(a)(i)**].

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	Cross-State Air Pollution Rule The Permittee shall comply with the monitoring requirements found in §97.406, §97.430, §97.431, §97.432, and §97.433 for the NOx Annual Trading Program and §97.506, §97.530, §97.531, §97.532, and §97.533 for the NOx Ozone Season Trading Program. D. Carbon Monoxide Emissions The Permittee shall perform preventative maintenance on the turbines to maintain them in a condition such that they operate as designed [**Reference: COMAR 26.11.03.06C**]. E. Volatile Organic Compounds The Permittee shall perform preventative maintenance on the turbines to maintain them in a condition such that they operate as designed. [**Reference: COMAR 26.11.03.06C**]. F. Particulate Matter Emissions The Permittee shall perform preventative maintenance on the turbines to maintain them in a condition such that they operate as designed. [**Reference: COMAR 26.11.03.06C**]. G. Operational Limitation See record keeping
1.4	**Record Keeping Requirements:** **NOTE:** All records must be maintained for a period of 5 years [**Reference: COMAR 26.11.03.06.C (5) (g)**]. A. Visible Emissions Limitation The Permittee shall: (1) Maintain a log of maintenance performed that relates to combustion performance on the combustion turbines; and (2) Maintain a log of visible emissions observation performed on site for 5 years and make it available to the Department's representative upon request. [**Reference: COMAR 26.11.03.06C**]. B. Sulfur Oxide and Sulfuric Acid Mist Emissions **CPCN and NSPS Subpart GG** The Permittee shall maintain all records including the fuel analyses for 2 years and shall make the record available to the Department upon request [**References: CPCN No 9341 Condition 14**]. **Note:** Part 70 permits require records to be maintained for 5 years rather than 2 years as referenced in the CPCN condition. **NSPS Subpart GG (40 CFR 60.7 (f))**

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"An owner or operator who is subject to the provisions of this part shall maintain a record of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by this part recorded in a permanent form suitable for inspection."
[**Reference: 40 CFR 60 .7(f)].**

Cross-State Air Pollution Rule
The Permittee shall comply with the recordkeeping requirements found in §97.606, §97.630, and §97.634.

Nitrogen Oxide Emissions

C. **CPCN**

The Permittee shall maintain all records necessary to comply with the NOx data reporting requirements of CPCN No. 9341, Condition 14 [**CPCN No. 9341, Condition No. 14, Air Quality Section]**

NSPS Subpart GG (40 CFR 60.7 (f))

"An owner or operator who is subject to the provisions of this part shall maintain a record of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by this part recorded in a permanent form suitable for inspection."
[Reference: 40 CFR 60 .7(f)].

NOx RACT
The Permittee shall maintain annual fuel use records and records that are necessary to submit with the quarterly emissions report [**References: COMAR 26.11.09.08K(3) and COMAR 26.11.03.06C**].

Cross-State Air Pollution Rule
The Permittee shall comply with the recordkeeping requirements found in §97.406, §97.430, and §97.434 for the NOx Annual Trading Program; and §97.506, §97.530, and §97.534 for the NOx Ozone Season Trading Program.

D. Carbon Monoxide Emissions
The Permittee shall maintain records of the preventative maintenance which relate to combustion performance [**References: COMAR 26.11.03.06C**].

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	E. Volatile Organic Compounds The Permittee shall maintain records of the preventative maintenance which relate to combustion performance [**References: COMAR 26.11.03.06C**]. F. Particulate Matter Emissions The Permittee maintain records of the preventative maintenance which relate to combustion performance [**References: COMAR 26.11.03.06C**]. G. Operational Limitation The Permittee shall maintain record of the hours that the turbines burn ULSD fuel oil and record periods, except for startups, shutdowns, and Black Start Events when each combustion turbine generator operates with water injection not engaged [**Reference: COMAR 26.11.03.06C**].
1.5	**Reporting Requirements:** A. Visible Emissions Limitation The Permittee shall report incidents of visible emissions in accordance with Condition 4 of Section III "Report of Excess Emissions and Deviation. [**Reference: COMAR 26.11.03.06C**]. B. Sulfur Oxide and Sulfuric Acid Mist Emissions **CPCN** The Permittee shall submit quarterly, within 45 days of the end of each quarter, the result of the sulfur content of the fuel to the Department within 45 days of the availability of the result [**Reference: CPCN No. 9341, Air Quality Section, Condition No. 14**]. **Note:** For any calendar quarter during which no delivery of ULSD fuel oil is received, the quarterly report shall state that no ULSD fuel oil was received during the quarter. **NSPS** For each affected unit required to continuously monitor parameters or emissions or to periodically determine the sulfur content or fuel nitrogen content under this subpart, the owner or operator shall submit reports of excess emissions and monitor downtime, in accordance with section 60. 7(c). Excess emissions shall be reported for all periods of unit operation, including startup, shutdown and malfunction. For the purpose of reports required under section 60.7(c), periods of excess emissions and monitor downtime, which shall be reported are defined as follows: (i) For samples of gaseous fuel and for ULSD fuel oil samples obtained using daily sampling, flow proportional sampling or sampling from unit's storage tank, an excess emission occurs each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the

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fuel being fired in the gas turbines exceeds 0.8 weight percent and ending on a date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit.

(ii) If the option to sample each delivery of fuel oil has been selected, the Permittee shall immediately switch to one of the other oil sampling options (i.e., daily sampling, flow proportional sampling, or sampling from the unit's storage tank from) if the sulfur content of a delivery exceeds 0.8 weight percent. The Permittee shall continue to use one of the other sampling options until all of the oil from the delivery has been combusted, and shall evaluate excess emissions according to paragraph (j)(2)(i) of this section. When all of the fuel from the delivery has been burned, the owner or operator may resume using the as delivered sampling option.

(iii) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor's downtime also begins on the date and hour of a required sample, if invalid results are obtained. The period of monitor downtime shall include only unit operating hours, and ends on the date and hour of the next valid sample. [**Reference: 40 CFR 60.334(j)(2)(i),(ii), and (iii)**].

All reports required under §60.7(c) shall be postmarked by the 30th day following the end of each calendar quarter [**Reference: 40 CFR 60.334(j)(5)**].

Cross-State Air Pollution Rule
The Permittee shall comply with the reporting requirements found in §97.606, §97.630, §97.633 and §97.634.

C. Nitrogen Oxide Emissions

CPCN (Note: see Reporting requirement G.)

RACT

The Permittee shall submit a quarterly summary report to the Department not later than 30 days following each calendar quarter. The report shall be in a format approved by the Department, and shall include the following:

(1) The cause, time periods, and magnitude of all emissions which exceed the applicable emission standards;
(2) The source downtime including the time and date of the beginning and end of each downtime period and whether the source downtime was planned or unplanned;
(3) The time periods and cause of all CEM downtime including records of any repairs, adjustments, or maintenance that may affect the validity of emission data;

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	(4) Quarterly totals of excess emissions, installation downtime, and CEM downtime during the calendar quarter; (5) Quarterly quality assurance activities; and (6) Daily calibration activities that include reference values, actual values, absolute or percent of span differences, and drift status; and (7) Other information required by the Department that is determined to be necessary to evaluate the data, to ensure that compliance is achieved, or to determine the applicability of this regulation." **[Reference: COMAR 26.11.09.08K(1) and COMAR 26.11.01.11E(2)(C)].** **Note:** The Permittee may submit one report that includes the required information to satisfy RACT and CPCN quarterly reporting requirements (See Reporting Condition G of CPCN). **[Reference: COMAR 26.11.03.06C]** **NSPS** For each affected unit required to continuously monitor parameters or emissions or to periodically determine the sulfur content or fuel nitrogen content under this subpart, the Permittee shall submit reports of excess emissions and monitor downtime, in accordance with section 60. 7(c). Excess emissions shall be reported for all periods of unit operation, including startup, shutdown and malfunction. For the purpose of reports required under section 60.7(c), periods of excess emissions and monitor downtime that shall be reported are defined as follows: For turbines using NO_X and diluent CEMS: (A) An hour of excess emissions shall be any unit operating hour in which the 4-hour rolling average NO_X concentration exceeds the applicable emission limit in §60.332(a)(1) or (2). For the purposes of this subpart, a "4-hour rolling average NO_X concentration" is the arithmetic average of the average NO_X concentration measured by the CEMS for a given hour (corrected to 15 percent O_2 and, if required under §60.335(b) (1), to ISO standard conditions) and the three unit operating hour average NO_X concentrations immediately preceding that unit operating hour. (B) A period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour, for either NO_X concentration or diluent (or both). (C) Each report shall include the ambient conditions (temperature, pressure, and humidity) at the time of the excess emission period and (if the Permittee has claimed an emission allowance for fuel bound nitrogen) the nitrogen content of

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the fuel during the period of excess emissions. You do not have to report ambient conditions if you opt to use the worst-case ISO correction factor as specified in §60.334(b) (3) (ii), or if you are not using the ISO correction equation under the provisions of §60.335(b) (1) [**Reference: 40 CFR 60.334(j)(1)(iii)**].

All reports required under §60.7(c) shall be postmarked by the 30th day following the end of each calendar quarter [**Reference: 40 CFR 60.334(j)(5)**].

Cross-State Air Pollution Rule
The Permittee shall comply with the reporting requirements found in §97.406, §97.430, §97.433 and §97.434 for the NOx Annual Trading Program; and §97.506, §97.530, §97.533, and §97.534 for the NOx Ozone Season Trading Program.

D. Carbon Monoxide Emissions
The Permittee shall submit records of the preventative maintenance performed, which relate to combustion performance to the Department upon request [**Reference: COMAR 26.11.03.06C**].

E. Volatile Organic Compounds
CPCN

The Permittee shall submit records of the calculated hourly, daily, and cumulative annual VOC emissions and preventative maintenance performed, which relate to combustion performance to the Department upon request [**Reference: COMAR 26.11.03.06C** and **CPCN No. 9341, Condition No. 14, Air Quality Section]**

F. Particulate Matter Emissions
The Permittee shall submit records of the preventative maintenance performed, which relate to combustion performance to the Department upon request [**Reference: COMAR 26.11.03.06C**].

G. Operational Limitation
CPCN

The Permittee shall submit the quarterly report within 45 days of the end of each calendar quarter, and shall include at least the following for each turbine (monthly summaries):

(a) The total hours of operation;
(b) The number of hours of operation burning ULSD fuel oil;
(c) The total amount of ULSD fuel oil burned, in units of gallons per hour and MMBtu per hour during the quarter;

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	(d) The number of hours of operation burning natural gas and LNG; (e) The total amount of natural gas and LNG burned, in units of pounds per hour and MMBtu per hour during the quarter; (f) Times of start-up and shutdown and Black Start Events; (g) The megawatts of electricity produced by each turbine on an hourly basis; (h) Maximum hourly and average hourly NOx emissions, in units of ppmvd at 15 percent oxygen and pounds per hour, and the cumulative annual NOx emissions; (i) Any emissions in excess of NOx concentrations specified in this permit, including the amount of the emissions, the date(s) on which the excess emissions occurred, the length of time over which the excess emissions occurred, the reason(s) why the excess emissions occurred, and the corrective action taken, if required, to ensure that excess emissions do not occur in the future; and (j) Any periods, except startup, shutdowns, and Black Start Events that the turbine operated, for natural gas or LNG firing, when not in DLN premix mode or for firing on ULSD fuel oil, with water injection not engaged. The quarterly report as required above shall be in the format approved by the Department. Valid CEMS data are required for a minimum of 90 percent of the plant operating hours in each quarter **[References**: **CPCN 9341, Conditions Nos. 13 and 14]**.

A Permit Shield shall cover the applicable requirements identified for the emissions units listed in the table above.

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2.0	**Emissions Unit:** EU-3 One (1) Caterpillar diesel engine Model C175-20 rated at 4000 kW burning Ultra low-sulfur diesel fuel oil.
2.1	**Applicable Standards/Limits:** A. Control of Visible Emissions A1. **COMAR 26.11.09.05E(2) -** Emissions During Idle Mode. A person may not cause or permit the discharge of emissions from any engine, operating at idle, greater than 10 percent opacity. A2. **COMAR 26.11.09.05E(3) -** Emissions During Operating Mode. A person may not cause or permit the discharge of emissions from any engine, operating at other than idle conditions, greater than 40 percent opacity.

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A3. **COMAR 26.11.09.05E(4) -** Exceptions.

(a) Section E(2) of this regulation does not apply for a period of 2 consecutive minutes after a period of idling of 15 consecutive minutes for the purpose of clearing the exhaust system.

(b) Section E(2) of this regulation does not apply to emissions resulting directly from cold engine start-up and warm-up for the following maximum periods:
(i) Engines that are idled continuously when not in service: 30 minutes;
(ii) All other engines: 15 minutes.

(c) Section E(2) and (3) of this regulation do not apply while maintenance, repair, or testing is being performed by qualified mechanics

B. Control of Sulfur Dioxide Emissions

B1. **CPCN Case No. 9341 Air Quality Section, Condition No. 8**, which limits sulfur content in ULSD fuel oil to 0.0015 wt %.

B2. **COMAR 26.11.09.07A(2)(b)** " In Areas III and IV - Sulfur Content Limitations for Fuel. A person may not burn, sell, or make available for sale any fuel with a sulfur content by weight in excess of or which otherwise exceeds 0.3 percent by weight."

B3. **§60.4207(b) -** owners and operators of stationary CI ICE subject to this subpart with a displacement of less than 30 liters per cylinder that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR 80.510(b) for nonroad diesel fuel (15 ppm maximum), except that any existing diesel fuel purchased (or otherwise obtained) prior to October 1, 2010, may be used until depleted.

C. Control of Nitrogen Oxides

C1. **COMAR 26.11.36.03 - Requirements for Stationary Engines.**

A. "The owner or operator of an engine is subject to requirements under 40 CFR Part 63 Subpart ZZZZ, as applicable.

B. The owner or operator of an engine is subject to requirements under 40 CFR Part 60 Subpart IIII. In May 2015, the United States Court of Appeals for the District of Columbia Circuit vacated paragraphs 40 CFR 60.4211(f)(2)(ii)-(iii), and 63.6640(f)(2)(ii)-(iii). Therefore, engines subject to this chapter do not have to comply with those provisions."
Note: Black Start Events are periods of emergencies.

C2. NOx RACT Requirements

COMAR 26.11.09.08G – Requirements for Fuel-Burning Equipment with a Capacity Factor of 15 percent or less.

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(1) A person who owns or operates fuel-burning equipment with a capacity factor (as defined in 40 CFR Part 72.2) of 15 percent or less shall:
(a) Provide certification of the capacity factor of the equipment to the Department in writing;
(b) For fuel-burning equipment that operates more than 500 hours during a calendar year, perform a combustion analysis and optimize combustion at least once annually;
(c) Maintain the results of the combustion analysis and any stack tests at the site for at least 2 years and make these results available to the Department and the EPA upon request;
(d) Require each operator of an installation, except combustion turbines, to attend operator training programs at least once every 3 years, on combustion optimization that are sponsored by the Department, the EPA, or equipment vendors; and
(e) Maintain a record of training program attendance for each operator at the site, and make these records available to the Department upon request."

2**. COMAR 26.11.09.08B (5) -** Operator Training**.**
(a) **COMAR 26.11.09.08B (5)(a)** states that "for purposes of this regulation, the equipment operator to be trained may be the person who maintains the equipment and makes the necessary adjustments for efficient operation; and .

(b) **COMAR 26.11.09.08B (5)**(b) states that the operator-training course sponsored by the Department shall include an in-house training course that is approved by the Department."

C3**. NSPS Subpart IIII Limitations**

§60.4205(b) - Owners and operators of 2007 model year and later emergency stationary CI ICE with a displacement of less than 30 liters per cylinder that are not fire pump engines must comply with the emission standards for new nonroad CI engines in §60.4202, for all pollutants, for the same model year and maximum engine power for their 2007 model year and later emergency stationary CI ICE.

§60.4202(b) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pump engines to the emission standards specified in paragraphs (b)(1) through (2) of this section.

(1) For 2007 through 2010 model years, the emission standards in table 1 to this subpart, for all pollutants, for the same maximum engine power. - **N/A**

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(2) For 2011 model year and later, the certification emission standards for new nonroad CI engines for engines of the same model year and maximum engine power in CFR 89.112 and 40 CFR 89.113 for all pollutants.

D. Control of NESHAP

40 CFR Part 63 Subpart ZZZZ (NESHAP) - See NSPS Subpart IIII limitations.

Note: MACT subpart ZZZZ - "**§63.6590(c)(1) Stationary RICE subject to Regulations under 40 CFR 60. - "**An affected source that meets any of the criteria in paragraphs (c) (1) through (7) of this section must meet the requirements of this part by meeting the requirement of 40 CFR part 60 Subpart IIII, for compression ignition engine or 40 CFR part 60 Subpart JJJJ, for spark ignition engines. No further requirements apply for such engines under this part" **(Ref: 40 CFR §63.6590(c)(1)).**

E. Operational Requirements

E1. **§60.4206 -** Owners and operators of emergency stationary CI ICE must operate and maintain stationary CI ICE so as to achieve the emission standards as required in §60.4205 over the entire life of engine.

E2. **§60.4207** - Owners and operators of stationary CI ICE subject to this subpart with a displacement of less than 30 liters per cylinder that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR 80.510(b) for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to October 1, 2010, may be used until depleted.

E3. **§60.4211(a) -** The Permittee, owner and operator of a stationary CI ICE subject to the emissions standard of 40 CFR Part 60, Subpart IIII must do all of the following, except as permitted under paragraph (g) of this section:

(1) Operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's emission-related written instructions;

(2) Change only those emission-related settings that are permitted by the manufacturer; and

(3) Meet the requirements of 40 CFR parts 89, 94 and/or 1068, as they apply to you.

E4. **§60.4211(f) -** Owners and operators of an emergency stationary ICE must operate the emergency stationary ICE according to the requirements in paragraphs (f)(1), (f)(2)(i) and (f)(3) of this section. In order for the engine to be considered an emergency stationary ICE under this subpart, any operation other than emergency operation, maintenance and testing, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1), (f)(2)(i) and (f)(3) of this section, is prohibited. If you do not operate the engine according to the requirements in paragraphs (f)(1), (f)(2)(i) and (f)(3) of this section, the engine will not be considered an emergency engine under this subpart and must meet all

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requirements for non-emergency engines.

(1) There is no time limit on the use of emergency stationary ICE in emergency situations.

(2) You may operate your emergency stationary ICE for any combination of the purposes specified in paragraphs (f)(2)(i) of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraph (f)(3) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (f)(2)(i).

(i) Emergency stationary ICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency ICE beyond 100 hours per calendar year.

(3) Emergency stationary ICE may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing provided in paragraph (f)(2)(i) of this section. Except as provided in paragraph (f)(3)(i) of this section, the 50 hours per calendar year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(i) The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met:

(A) The engine is dispatched by the local balancing authority or local transmission and distribution system operator;

(B) The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.

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	(C) The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines. (D) The power is provided only to the facility itself or to support the local transmission and distribution system. (E) The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.
2.2	**Testing Requirements:** A. Visible Emissions Limitation See monitoring requirements B. Sulfur Oxide Emissions B1. See monitoring requirements for CPCN **No. 9341, Condition 8.** B2. See Monitoring requirements B3. See Monitoring requirements C. Nitrogen Oxide Emissions C1. See record keeping requirements. C2. For fuel-burning equipment that operates more than 500 hours during a calendar year, perform a combustion analysis for each combustion unit at least once each calendar year and optimize combustion based on analysis **[Authority: COMAR 26.11.09.08G(1)(b)].** C3. NSPS Subpart IIII The Permittee, owner or operator of a 2007 model year and later stationary CI internal combustion engine and must comply with the emission standards specified in §60.4204(b) or §60.4205(b ……..must comply by purchasing an engine certified to the emission standards in §60.4204(b), or §60.4205(b) … as applicable for the same model year and … engine power. The engine must be installed and configured according to the manufacturer's emission-related specifications, except as permitted in paragraph (g) of this section [**Authority: §60.4211(c)]**. D. Control of NESHAP See requirements for C3 above. **[Authority: 40 CFR §63.6590(c)(1).].**

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	E. Operational Requirements See monitoring requirements
2.3	**Monitoring Requirements:** A. Visible Emissions Limitation (1) The Permittee shall: (a) Properly operate and maintain the engine; and (b) Maintain an operations manual and preventive maintenance plan. **[Authority: COMAR 26.11.03.06C]** (2) The Permittee shall properly operate and maintain the engine in a manner to minimize visible emissions. **[Authority: COMAR 26.11.03.06C]** and shall operate and maintain the stationary CI internal combustion engine according to the manufacturer's written instructions or procedures developed by the owner or operator that are approved by the engine manufacturer. **[Authority**: **§60.4211(a)(1)].** B. Sulfur Oxide Emissions Limitation B1. The Permittee shall perform sampling and analysis of the "as fired" sulfur content of the ULSD fuel oil to determine the percentage of sulfur by weight in the fuel oil. The sampling procedures shall follow the requirements of CPCN No. 9341, Condition No. 8 as prescribed in 40 CFR 75 Appendix D, Sec. 2.2. [**Authority: CPCN No. 9341, Condition No. 8, Air Quality Section**]. B2. The Permittee shall obtain fuel supplier's certification, which includes the name of the oil supplier and statement from the fuel supplier that the distillate fuel oil complies with the limitation of 0.3% by weight of the sulfur content in the fuel oil. **[Authority: COMAR 26.11.03.06C].** B3. The Permittee shall comply with requirements under 40 CFR 60 subpart IIII. **Note:** The monitoring requirements for complying with the CPCN requirements shall be the basis for complying with both the COMAR and 40 CFR 60 subpart IIII requirements. **[Authority: COMAR 26.11.03.06C].** C. Nitrogen Oxide Emissions The Permittee shall: C1. See recordkeeping C2. Require each installation operators to attend operator training program on combustion optimization that are sponsored by the Department, U.S. EPA, or equipment vendors, once every three years. **[Authority: COMAR 26.11.03.06C and COMAR 26.11.09.08G(1)(d)].** Additionally**,** a Permittee who owns or

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	operates fuel-burning equipment with a capacity factor (as defined in 40 CFR Part 72.2) of 15 percent or less shall provide certification of the capacity factor of the equipment to the Department in writing. **[Authority: COMAR 26.11.03.06C and COMAR 26.11.09.08G(1)(a)].** C3. NSPS Subpart IIII **§60.4211(a) -** The Permittee, owner and operator of a stationary CI ICE subject to the emissions standard of 40 CFR Part 60, Subpart IIII must do all of the following, except as permitted under paragraph (g) of this section: (1) Operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's emission-related written instructions; (2) Change only those emission-related settings that are permitted by the manufacturer; and D. NESHAP See monitoring requirement C3 above. E. Operational Limitations The Permittee, owner or operator, must meet the monitoring requirements of this section. In addition, you must also meet the monitoring requirements specified in §60.4211. (a) If you are an owner or operator of an emergency stationary CI internal combustion engine that does not meet the standards applicable to non-emergency engines, you must install a non-resettable hour meter prior to startup of the engine. (b) If you are an owner or operator of a stationary CI internal combustion engine equipped with a diesel particulate filter to comply with the emission standards in §60.4204, the diesel particulate filter must be installed with a backpressure monitor that notifies the owner or operator when the high backpressure limit of the engine is approached. - **N/A [Authority: §60.4209].**
2.4	**Record Keeping Requirements:** **NOTE:** All records must be maintained for a period of 5 years [**Reference: COMAR 26.11.03.06.C (5) (g)**]. A. Visible Emissions Limitation The Permittee shall maintain records of the preventive maintenance that relates to combustion process performed on the engine on site for at least 5 years and make the records available to the Department upon request. The Permittee shall also retain the operations manual on site and make it available to the Department upon request

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[**Authority: COMAR 26.11.03.06C].**

B. Sulfur Oxide Emissions

B1. The Permittee shall maintain records of fuel sampling and analysis for the "as fired" sulfur content of the ULSD fuel oil utilized in the engine for at least five years. [**Reference: CPCN No. 9341, Condition No. 14, Air Quality Section**].

B2. – B3. The Permittee shall maintain records of fuel suppliers' certifications of the percent sulfur content in the fuel on site for at least five years and shall make the records available to the Department upon request. The fuel oil certification report must contain the type, quantities, and analyses of all fuels burned. **[Authority: COMAR 26.11.09.07C].**

C. Nitrogen Oxide Emissions

C1. The Permittee shall maintain a record of the date and time of the operation of the generator.

C2. NOx RACT -
The Permittee shall:

(a) Maintain records of the result of the combustion analysis at the site and make the records available to the Department and EPA upon request. **[Authority: COMAR 26.11.09.08G(c)].**

(b) Prepare and maintain a record of training program attendance for each operator at the site, and make these records available to the Department upon request; **[Authority: COMAR 26.11.09.08E(1)(e) and COMAR 26.11.09.08G (1)(e)].**

(c) Records of the calculated capacity factors on site for at least five years. **[Authority: COMAR 26.11.09.08G (1)(a)].**

(d) The Permittee shall maintain annual fuel use records and records that are necessary to submit with the quarterly emissions report. [**References: COMAR 26.11.09.08K(3) and COMAR 26.11.03.06C**].

C3. NSPS Subpart IIII

The Permittee shall maintain records of the initial performance test, if a test is conducted, to demonstrate initial compliance with applicable emission standards in accordance with §60.4212 and shall maintain records of the established operating parameters to be monitored continuously to ensure the stationary internal combustion engine continues to meet the emission standards. **[Authority: COMAR 26.11.03.06C and §60.4211(f)].**

D. NESHAP

See record keeping requirements for C3 above.

E. Operational Limitation

The Permittee shall maintain, on site, a record of operation of the engine to include fuel consumption, the hours of operation and purpose of operation - whether

Table IV – 2	
	emergency or non-emergency situations such as maintenance and testing, etc – as necessitated by the operating requirements of §60.4211(f) and make the record available to the Department upon request. **[Authority: COMAR 26.11.03.06C and §60.4211(f)].**
2.5	**Reporting Requirements:** A. Visible Emissions Limitation The Permittee shall report incidents of visible emissions in accordance with Condition 4 of Section III "Report of Excess Emissions and Deviation. [**Reference: COMAR 26.11.03.06C**]. B. Sulfur Oxide Emissions B1. The Permittee shall submit, within 45 days of the end of each quarter, the result of the sulfur content of the fuel to the Department [**Reference: CPCN No. 9341, Air Quality Section, Condition No. 14**]. B2. - B3. The Permittee shall submit the fuel supplier certification or a copy of the sulfur in fuel analyses to the Department upon request. **[Authority: COMAR 26.11.09.07C].** **Note 1:** For any calendar quarter during which no delivery of fuel oil is received, the quarterly report shall state that no fuel was received during the quarter. **Note 2:** Note: The Permittee may submit one report that includes the required information to satisfy RACT and CPCN quarterly reporting requirements (See Reporting Condition G for CPCN). **[Reference: COMAR 26.11.03.06C]** C. Nitrogen Oxide Emissions **RACT** See Recordkeeping Requirements for records to submit when requested by the Department - COMAR 26.11.09.08G(1)(c) and (e). D. NESHAP See requirements for regulatory requirement C above. E. Operational Limitation The Permittee shall submit semi-annually or as appropriate, a report of all relevant operating records to include the hours of operation and purpose of operation of the engine - whether emergency or non-emergency situations such as maintenance and testing, etc – as necessitated by the operating requirements of §60.4211(f). **[Authority: COMAR 26.11.03.06C and §60.4211(f)].**

A Permit Shield shall cover the applicable requirements identified for the emissions unit listed in the table above.

SECTION V INSIGNIFICANT ACTIVITIES

This section provides a list of insignificant emissions units that were reported in the Title V permit application. The applicable Clean Air Act requirements, if any, are listed below the insignificant activity.

(1) No. 1 Stationary internal combustion engines with an output less than 500 brake horsepower (373 kilowatts) and which are not used to generate electricity for sale or for peak or load shaving;

The diesel fuel fired fire protection engine/pump is subject to the following requirements:

(a) **COMAR 26.11.09.05E(2) –** "Emissions During Idle Mode. A person may not cause or permit the discharge of emissions from any engine, operating at idle, greater than 10 percent opacity."

(b) **COMAR 26.11.09.05E(3) – "**Emissions During Operating Mode. A person may not cause or permit the discharge of emissions from any engine, operating at other than idle conditions, greater than 40 percent opacity."

(c) **COMAR 26.11.09.05E(4)** "Exceptions:

(i) Section E(2) does not apply for a period of 2 consecutive minutes after a period of idling of 15 consecutive minutes for the purpose of clearing the exhaust system;

(ii) Section E(2) does not apply to emissions resulting directly from cold engine start-up and warm-up for the following maximum periods:

(1) Engines that are idled continuously when not in service: 30 minutes,
(2) All other engines: 15 minutes; and

(iii) Section E(2) and (3) does not apply while maintenance, repair, or testing is being performed by qualified mechanics."

(d) **COMAR 26.11.09.07A(2)(b)** " In Areas III and IV - Sulfur Content Limitations for Fuel. A person may not burn, sell, or make available for sale any fuel with a sulfur content by weight in excess of or which otherwise exceeds 0.3 percent by weight."

(2) __√__ Space heaters utilizing direct heat transfer and used solely for comfort heat;

(3) No._75_ Unheated VOC dispensing containers or unheated VOC rinsing containers of 60 gallons (227 liters) capacity or less;

(4) Containers, reservoirs, or tanks used exclusively for:

(a) __√__ Storage of butane, propane, or liquefied petroleum, or natural gas;

(b) No._20_ Storage of lubricating oils;

(c) No._ 3_ Storage of ULSD fuel oil;

(d) No._30_ The storage of VOC normally used as solvents, diluents, thinners, inks, colorants, paints, lacquers, enamels, varnishes, liquid resins, or other surface coatings and having individual capacities of 2,000 gallons (7.6 cubic meters) or less;

(5) __√__ Certain recreational equipment and activities, such as fireplaces, barbecue pits and cookers, fireworks displays, and kerosene fuel use;

SECTION VI STATE ONLY ENFORCEABLE CONDITIONS

The Permittee is subject to the following State-only enforceable requirements:

Applicable Regulations/Limits:

1. **COMAR 26.11.06.08**
"An installation or premises may not be operated or maintained in such a manner that a nuisance or air pollution is created. Nothing in this regulation relating to the control of emissions may in any manner be construed as authorizing or permitting the creation of, or maintenance of, nuisance or air pollution."

2. **COMAR 26.11.06.09**
"A person may not cause or permit the discharge into the atmosphere of gases, vapors, or odors beyond the property line in such a manner that a nuisance or air pollution is created."

3. **COMAR 26.09.01, .02, .03, and .04** - Maryland's CO2 Budget and Trading Program, which requires the Permittee to comply with the provisions and requirements of Maryland's CO_2 Budget and Trading Program. The Permittee shall comply with the CO_2 Budget and Trading Permit that is attached to the Part 70 permit. See Attachment 1.

Maryland Department of the Environment
Air and Radiation Administration

PHASE II ACID RAIN PERMIT

Plant Name: Brandywine Power Facility	
Affected Units: 1 and 2	
Owner: KMC Thermo, LLC.	ORIS Code 54832
Effective Date From: To: January 31, 2025	

Contents:

1. Statement of Basis.

2. SO_2 and NO_x requirements for each affected unit.

3. Comments, notes and justifications regarding permit decisions and changes made to permit application forms during the review process, and any additional requirements or conditions.

4. The permit application forms submitted for this source. The owners and operators of the source must comply with the standard requirements and special provisions set forth in the application.

1. Statement of Basis

Statutory and Regulatory Authorities: In accordance with Environmental Article § 2-401, Annotated Code of Maryland and Titles IV and V of the Clean Air Act, the Maryland Department of the Environment, Air and Radiation Administration issues this permit pursuant to COMAR 26.11.02 and COMAR 26.11.03.

Permit Approval

_____ _____

George S. Aburn, Jr., Director
Air and Radiation Administration

Date of Issue

Plant Name: Brandywine Power Facility

2. SO_2 and NO_x Requirements for each affected unit

Units No. 1 and 2

SO_2 Requirements	
SO_2 Allowances	KMC Thermo, LLC Company - Brandywine Power Facility will hold allowances for these units in accordance with 40 CFR 72.9(c)(1).

NO_x Requirements	
NO_x Limit	None

3. Comments, notes and justifications regarding decisions, and changes made to the permit application forms during the review process:

These units burn natural gas or No. 2 fuel oil. Because these units are not coal fired, the oxides of nitrogen emissions reduction regulations of 40 CFR Part 76 are not applicable.

KMC Thermo, LLC became the new owner of Brandywine Power Facility on July 1, 2014.

Permit Approval

George S. Aburn, Jr., Director _____ Date of Issue _____
Air and Radiation Administration

Maryland Department of the Environment
Air and Radiation Administration

CO_2 BUDGET TRADING PROGRAM PERMIT

Plant Name: Brandywine Power Facility	
Affected Trading Units: Units 1 & 2	
Owner: KMC Thermo, LLC	ORIS Code 54832
Effective Date From: To: January 31, 2025	

Contents:

1. Statement of Basis
2. Table of Affected Units
3. Standard Requirements.
4. The permit application forms submitted for this source.

1. Statement of Basis

Statutory and Regulatory Authorities: In accordance with Environmental Article §2-401, Annotated Code of Maryland, the Maryland Department of the Environment, Air and Radiation Administration issues this permit pursuant to COMAR 26.09.01 thru COMAR 26.09.04.

Permit Approval

_____ _____

George S. Aburn, Jr., Director
Air and Radiation Administration

Date of Issue

2. Affected Units

Unit ID #	Unit Description
Unit 1	GE Frame 7EA CT rated at 84 MW.
Unit 2	GE Frame 7EA CT rated at 84 MW.

Standard Requirements:

(A) Selection and Responsibilities of CO_2 Budget Source Compliance Account Authorized Account Representatives.

(1) Each CO_2 budget source shall have a CO_2 authorized account representative and an alternate CO_2 authorized account representative.
(COMAR 26.09.01.04B)

(2) Upon receipt of a complete account certificate of representation:

(a) The CO_2 authorized account representative and alternate CO_2 authorized account representative shall represent and, by representations, actions, inactions, or submissions, legally bind each owner or operator of the CO_2 budget source represented and each CO_2 budget unit at the source in all matters pertaining to this subtitle, notwithstanding any agreement between the CO_2 authorized account representative, alternate CO_2 authorized account representative, and the owners or operators;
(COMAR 26.09.01.04E (1))

(b) The owners or operators shall be bound by any decision or order issued to the CO_2 authorized account representative or alternate CO_2 authorized account representative by the Department or a court regarding the CO_2 budget source or unit.
(COMAR 26.09.01.04E (2))

(3) A CO_2 budget permit may not be issued or a compliance account established for a CO_2 budget source until the Department has received a complete account certificate of representation for a CO_2 authorized account representative and alternate CO_2 authorized account representative of the source and the CO_2 budget units at the source.
(COMAR 26.09.01.04F)

(4) Each submission shall be signed and certified by the CO_2 authorized account representative or alternate CO_2 authorized account representative on behalf of each CO_2 budget source and shall include the following statement by the CO_2 authorized account representative or alternate CO_2 authorized account representative: "I am authorized to make the submission on behalf of the owners or operators of the CO_2 budget sources or CO_2 budget units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in the document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."
(COMAR 26.09.01.04G)

(B) Distribution Of CO_2 Allowances And Compliance

(1) Unless otherwise specified in this chapter, a CO_2 budget source shall demonstrate compliance with its CO_2 budget emissions limitation by having one CO_2 allowance in its compliance account for every ton of CO_2 that it emits in a control period, by the allowance transfer deadline for that control period.
(COMAR 26.09.02.03E(1))

(2) The following CO_2 allowances may be deducted from a compliance account for purposes of complying with a budget source's CO_2 budget emissions limitation for a certain control period

(a) CO_2 allowances that are not CO_2 offset allowances and are identified as allowances falling within a prior control period or the same control period for which the allowances are deducted;

(b) CO_2 allowances that are held or transferred into the CO_2 budget source's compliance account as of the CO_2 allowance transfer deadline for that control period;

(c) CO_2 offset allowances that are available to be deducted for compliance during a control period may not exceed the following:

(i) 3.3 percent;

(ii) 5 percent, if the Department determines that there has been a Stage 1 trigger event; and

(iii) 10 percent, if the Department determines that there has been a Stage 2 trigger event.
(COMAR 26.09.02.03E(2)(a)-(c))

(3) The Department shall deduct CO_2 allowances from the CO_2 budget source's compliance account until the number of CO_2 allowances deducted equals the number of tons of total CO_2 emissions, less any CO_2 emissions attributable to the burning of eligible biomass.
(COMAR 26.09.02.03E (3))

(4) The identification of available CO_2 allowances for compliance deduction by serial number or by default is as follows:

(a) The CO_2 authorized account representative for a source's compliance account may request that specific CO_2 allowances, identified by serial number for a control period, be deducted; and

(b) In the absence of an identification or in the case of a partial identification of available CO_2 allowances by serial number, the Department shall deduct CO_2 allowances for a control period in the following descending order:

(i) For the first control period, all CO_2 allowances purchased by direct sale from the Department during years 2009, 2010, and 2011 resulting from the occurrence of the $7 auction clearing price;

(ii) All CO_2 allowances for a control period allocated to a CO_2 budget unit from the Long Term Contract Set-aside Account or the Clean Generation Set-aside Account;

(iii) Subject to the relevant compliance deduction limitations identified in §E(2)(c) of this regulation, any CO_2 offset allowances transferred and recorded in the compliance account, in chronological order; and

(iv) Any CO_2 allowances, other than those identified in §E(4)(b)(i) - (iii) of this regulation, that are available for deduction in the order they were recorded.

(COMAR 26.09.02.03E (4)(a)-(b))

(5) Deductions for Excess Emissions:

(a) If a CO_2 budget source has excess emissions, the Department shall deduct, from the CO_2 budget source's compliance account, CO_2 allowances from allocation years that occur after the control period in which the source has excess emissions that equal three times the number of the source's excess emissions.

(b) If a source has insufficient CO_2 allowances to cover three times the number of the source's excess emissions, the source shall immediately transfer sufficient allowances into its compliance account.

(c) CO_2 offset allowances may not be deducted to account for the source's excess emissions.

(d) Any CO_2 allowance deduction does not affect the liability of the owners or operators of the CO_2 budget units at the source for any fine, penalty, or assessment, or their obligation to comply with any other remedy, for the same violation, as ordered under applicable State law.
(COMAR 26.09.02.03E (5)(a)-(d))

(6) The following guidelines apply in assessing fines, penalties, or other obligations:

(a) For purposes of determining the number of days of violation, if a CO_2 budget unit has excess emissions for a control period, each day in the control period constitutes a day of violation unless the owners or operators of the unit can demonstrate to the satisfaction of the Department that a lesser number of days should be considered; and

(b) The Department shall consider the amount of excess emissions in determining the severity of the violation.
(COMAR 26.09.02.03E (6)(a)-(b))

(7) If the CO_2 budget source's compliance account no longer exists, the CO_2 allowances shall be deposited in a general account selected by the owner or operator of the CO2 budget source.
(COMAR 26.09.02.03E (7))

(8) Adjustments and Errors:

(a) The Department may review and conduct independent audits concerning any submission under this subtitle and make appropriate adjustments of the information, if necessary.

(b) The Department may correct any error in any account and, within 10 business days of making any correction, notify the CO_2 authorized account representative for the account
(COMAR 26.09.02.03E (8)(a)-(b))

(C) Applicability and Administration

(1) The requirements of this permit apply to the owner or operator of a CO_2 budget unit. When this permit establishes a requirement such as the submittal of a permit application, a report, a request for allowances or transfer of allowances, or general information, these actions shall be achieved through the authorized account representative on behalf of the owner or operator of the affected CO_2 budget source or unit.
(COMAR 26.09.02.02A)

(2) The requirements of this subtitle are effective on January 1, 2009 or, for new CO_2 budget units, on the day on which the unit commences operation.

(COMAR 26.09.02.02C).

(3) The provisions of this permit do not exempt or otherwise relieve the owners or operators of a CO_2 budget source from achieving compliance with any other provision of applicable State and federal laws and regulations.
(COMAR 26.09.02.02D).

(4) Unless otherwise stated under this subtitle, any time period scheduled to begin:

(a) On the occurrence of an act or event, begins on the day the act or event occurs; and

(b) Before the occurrence of an act or event, is computed so that the period ends the day before the act or event occurs.
(COMAR 26.09.02.02F)

(5) Unless otherwise stated, if the final day of any time period for performing an act required by this subtitle falls on a weekend or on a State or federal holiday, the time period is extended until or to the next business day.
(COMAR 26.09.02.02G)

(D) Permit Requirements

(1) The account representative or designate alternate account representative) of each affected unit at a source, (every fossil fuel fired unit with a nameplate capacity of 25 MW or greater) for that source shall comply with the following:

(a) The CO_2 authorized account representative for the source shall submit an initial CO_2 budget permit application by October 1, 2008, or 12 months before the date on which the CO_2 budget source, or a new unit at the source, commences operation.
(COMAR 26.09.02.04A (2));

(b) The CO_2 budget permit application shall include the following in a format prescribed by the Department: 1) the identification of the CO_2 budget source; 2) facility name and the ORIS (Office of Regulatory Information Systems) or facility code assigned to the source by the Energy Information Administration of the U. S. Department of Energy, if applicable; 3) each CO_2 budget unit at the source; and 4) other information required by the Department.
(COMAR 26.09.02.04A (3))

(c) The authorized account representative for the source shall submit a complete application for the renewal of an existing CO_2 budget permit on forms provided by the Department not later than 90 days before the expiration of the current CO_2 budget permit.
(COMAR 26.09.02.04 E)

(2) The owners and operators of each affected source shall have a CO_2 Budget Trading Program permit (the "budget permit") issued by the Department.
(COMAR 26.09.02.04A (1)).

(3) The CO_2 budget permit issued by the Department shall be separate but attached to the budget source's Part 70 permit.
(COMAR 26.09.02.04B).

(4) A CO_2 budget permit expires 5 years from the date of issuance by the Department, unless an earlier expiration date is specified in the permit.
(COMAR 26.09.02.04D)

(E) Monitoring, Initial Certification and Recertification Requirements

(1) For each control period in which a CO_2 budget source is subject to the CO_2 budget emissions limitation, the CO_2 authorized account representative of the source shall submit a compliance certification report by the March 1 following the relevant control period.
(COMAR 26.09.02.05 A (1)).

(2) The CO_2 authorized account representative shall include in the compliance certification report the following:

(a) Identification of the source and each CO_2 budget unit at the source;

(b) At the CO_2 authorized account representative's option, the serial numbers of the CO_2 allowances that are to be deducted from the source's compliance account for the control period, including the serial numbers of any CO_2 offset allowances that are to be deducted subject to applicable limitations; and

(c) The compliance certification required by Condition (d)(3) of this permit.
(COMAR 26.09.02.05 A (2)).

(3) In the compliance certification report, the CO_2 authorized account representative shall certify whether the source and each CO_2 budget unit at the source for which the compliance certification is submitted was operated during the control period in compliance with the requirements of this subtitle, including:

(a) Whether each CO_2 budget unit at the source was operated in compliance with the CO_2 budget emissions limitation;

(b) Whether the monitoring plan applicable to each unit at the source has been maintained to reflect the actual operation and monitoring of the unit and contains all information necessary to track CO_2 emissions from the unit;

(c) Whether all CO_2 emissions from each unit at the source were monitored or accounted for through the missing data procedures and reported in the quarterly monitoring reports, including: identification of all conditional data reported in the quarterly reports; and if conditional data were reported, whether the status of all conditional data has been resolved and all necessary quarterly report resubmissions have been made;

(d) Whether the basis for certification or for using an excepted monitoring method or approved alternative monitoring method has changed;

(e) If a change is required to be reported, include: the nature and reasons for the change; when

the change occurred; and how the unit's compliance status was determined after the change, including the method used to determine emissions when a change mandated the need for monitor recertification.
(COMAR 26.09.02.05A (3) (a)-(e))

(4) The Department, at its discretion, may review and conduct independent audits of any compliance certification or other submission required by this permit.
(COMAR 26.09.02.05 B (1))

(5) The Department may deduct CO_2 allowances from, or transfer CO_2 allowances to, a compliance account to correct errors in the account or to accurately reflect CO_2 emissions, based on the information in the compliance certification or other submissions.
(COMAR 26.09.02.05 B (2))

(6) The owner or operator of a CO_2 budget unit shall:

(a) Install monitoring systems to monitor CO_2 concentration, stack gas flow rate, oxygen concentration, heat input, and fuel flow rate;

(b) Install all monitoring systems in accordance with 40 CFR Part 75, except for equation G-1 in Appendix G (attached at the end of this permit); and

(c) Record, report, and verify the data from the monitoring systems.
(COMAR 26.09.02.10A (1) (a)-(c))

(7) Install and certify the monitoring system on or before the following dates:

(a) For a CO_2 budget unit that commences commercial operation before July 1, 2008, the owner or operator shall comply on or before January 1, 2009; and

(b) For a CO_2 budget unit that commences commercial operation or constructs a new stack or flue on or after July 1, 2008, the owner or operator shall comply by January 1, 2009, or 90 operating days after the date on which the unit commences commercial operation.
(COMAR 26.09.02.10 A (1) (d))

(8) The owner or operator of a CO_2 budget unit that does not meet the applicable compliance date shall, in accordance with the provisions in 40 CFR §75.31(b)(2) or (c)(3), or §2.4 of Appendix D, determine, record, and report maximum potential or, as appropriate, minimum potential for the following:

(a) CO_2 concentration;

(b) CO_2 emissions rate;

(c) Stack gas moisture content;

(d) Fuel flow rate; and

(e) Any other parameter required to determine CO_2 mass emissions.
(COMAR 26.09.02.10 A (2) (a)-(e))

(9) The owner or operator of a CO_2 budget unit that does not meet the applicable compliance date for any monitoring system shall determine, record, and report substitute data using the applicable missing data procedures in 40 CFR Part 75 Subpart D, or Appendix D, instead of the maximum potential values or, as appropriate, minimum potential values for a parameter, if the owner or operator demonstrates that there is continuity between the data streams for that parameter before and after the construction or installation.
(COMAR 26.09.02.10 A (3))

(10) An owner or operator of a CO_2 budget unit or a non-CO_2 budget unit monitored under 40 CFR §75.72 (b) (2) (ii) may not:

(a) Use any alternative monitoring system, alternative reference method, or any other alternative for the required continuous emissions monitoring system without having obtained prior written approval from the Department;

(b) Operate the unit so as to discharge, or allow to be discharged, CO_2 emissions to the atmosphere without accounting for all emissions in accordance with the applicable provisions of this chapter and 40 CFR Part 75;

(c) Disrupt the operation of the CEMS, any portion of the CEMS, or any other approved emissions monitoring method, and thereby avoid monitoring and recording CO_2 mass emissions discharged into the atmosphere, except for periods of recertification or periods when calibration, quality assurance testing, or maintenance is performed; or

(e) Permanently discontinue use of the approved CEMS unless the owner or operator monitors emissions with a system approved in accordance with this chapter and 40 CFR Part 75.
(COMAR 26.09.02.10 A (4) (a)-(e))

(11) For purposes of this subtitle only, the owner or operator of a CO_2 budget unit is exempt from demonstrating compliance with the initial certification requirements of 40 CFR §75.20 for a monitoring system if the following conditions are met:

(a) The monitoring system has been previously certified in accordance with 40 CFR §75.20; and

(b) The applicable quality assurance and quality-control requirements of 40 CFR §75.21 and Appendix B and Appendix D of 40 CFR Part 75 are fully met for the certified monitoring system.
(COMAR 26.09.02.10 B (1) (a)-(b))

(12) The recertification provisions of this regulation apply to a monitoring system exempt from the initial certification requirements of this regulation.
(COMAR 26.09.02.10 B (2))

(13) If the Department has previously approved a petition under 40 CFR §75.72(b)(2)(ii) or 40 CFR §75.16(b)(2)(ii)(B) pursuant to 40 CFR §75.13 for apportioning the CO_2 emissions rate measured in a common stack or a petition under 40 CFR §75.66 for an alternative requirement in 40 CFR Part 75, the CO_2 authorized account representative shall resubmit the petition to the Department to determine whether the approval applies under this chapter.
(COMAR 26.09.02.10 B (3))

(14) The owner or operator of a CO_2 budget unit shall comply with the initial certification and recertification procedures for a CEMS and an excepted monitoring system under 40 CFR Part 75, Appendix D.
(COMAR 26.09.02.10 B (4))

(15) The owner or operator of a unit that qualifies to use the low mass emissions excepted monitoring methodology in 40 CFR §75.19 or that qualifies to use an alternative monitoring system under 40 CFR Part 75, Subpart E, shall comply with this regulation.
(COMAR 26.09.02.10 B (5))

(16) When the owner or operator replaces, modifies, or changes a CEMS that the Department determines significantly affects the ability of the system to accurately measure or record CO_2 mass emissions or to meet the quality assurance and quality control requirements of 40 CFR §75.21 or Appendix B, the owner or operator shall recertify the monitoring system according to 40 CFR §75.20(b).
(COMAR 26.09.02.10 C (1))

(17) When the owner or operator replaces, modifies, or changes the flue gas handling system or the unit's operation in a manner that the Department determines has significantly changed the flow or concentration profile, the owner or operator shall recertify the CEMS according to 40 CFR §75.20(b).
(COMAR 26.09.02.10 C (2))

(18) Approval Process for Initial Certifications and Recertification. The procedures in 40 CFR §75.20(b)(5) and (g)(7) apply for recertification. The CO_2 authorized account representative shall submit to the Department:

(a) A written notice of the dates of certification; and

(b) A recertification application for each monitoring system, including the information specified in 40 CFR §75.63.
(COMAR 26.09.02.10 C(3) (a)-(b))

(19) Provisional certification data for a monitor shall be:

(a) Determined in accordance with 40 CFR §75.20(a)(3);

(b) A provisionally certified monitor may be used for a period not to exceed 120 days after receipt of the complete certification application for the monitoring system or component; and

(c) Data measured and recorded by the provisionally certified monitoring system or component

is considered valid quality assured data, retroactive to the date and time of provisional certification, if the Department does not issue a notice of disapproval within 120 days of receipt of the complete certification application.
(COMAR 26.09.02.10 C (4) (a)-(c))

(20) The Department shall issue a written notice of approval or disapproval of the certification application to the owner or operator within 120 days of receipt of the complete certification application.
(COMAR 26.09.02.10 D (1))

(21) If the Department does not issue the notice within the 120-day period, each monitoring system that meets the applicable performance requirements of 40 CFR Part 75 and is included in the certification application shall be deemed certified for use.
(COMAR 26.09.02.10 D (2))

(22) If the certification application is complete and shows that each monitoring system meets the applicable performance requirements of 40 CFR Part 75, the Department shall issue a written notice of approval of the certification application within 120 days of receipt.
(COMAR 26.09.02.10 D (3))

(23) If the certification application is not complete, the Department shall issue a written notice of incompleteness that sets a reasonable date by which the CO_2 authorized account representative is to submit the additional information required to complete the certification application.
(COMAR 26.09.02.10 D (4))

(24) If the CO_2 authorized account representative does not comply with the notice of incompleteness by the specified date, the Department may issue a notice of disapproval.
(COMAR 26.09.02.10 D (5))

(25) If the Department issues a notice of disapproval of a certification application or a notice of disapproval of certification status, the owner or operator shall substitute the following values for each disapproved monitoring system, for each hour of unit operation during the period of invalid data beginning with the date and hour of provisional certification and continuing until the time, date, and hour specified under 40 CFR §75.20(a)(5)(i) or 75.20(g)(7):

(a) For units using or intending to monitor for CO_2 mass emissions using heat input or for units using the low mass emissions excepted methodology under 40 CFR §75.19, the maximum potential hourly heat input of the unit; or

(b) For units intending to monitor for CO_2 mass emissions using a CO_2 pollutant concentration monitor and a flow monitor, the maximum potential concentration of CO_2 and the maximum potential flow rate of the unit under 40 CFR Part 75, Appendix A, §2.1.
(COMAR 26.09.02.10 D (6) (a)-(b))

(26) The CO_2 authorized account representative shall submit a notification of certification retest dates and a new certification application. The owner or operator shall repeat all certification tests or other requirements that were failed by the monitoring system, as indicated in the Department's

notice of disapproval, not later than 30 operating days after the date of issuance of the notice of disapproval.
(COMAR 26.09.02.10 D (7))

(27) The owner or operator of a unit qualified to use the low mass emissions excepted methodology under 40 CFR §75.19 shall meet the applicable certification and recertification requirements of 40 CFR §§75.19(a) (2) and 75.20(h).
(COMAR 26.09.02.10 E (1))

(28) If the owner or operator of this unit elects to certify a fuel flow meter system for heat input determinations, the owner or operator shall also meet the certification and recertification requirements in 40 CFR §75.20(g).
(COMAR 26.09.02.10 E (2))

(29) Certification and Recertification Procedures for Alternative Monitoring Systems. For each unit for which the owner or operator intends to use an alternative monitoring system approved by the Department, 40 CFR Part 75, Subpart E, shall be used to comply with the applicable notification and application procedures of 40 CFR §75.20(f).
(COMAR 26.09.02.10 F)

(30) When any monitoring system fails to meet the quality assurance and quality control requirements or data validation requirements of 40 CFR Part 75, data shall be substituted using the applicable procedures in 40 CFR Part 75, Subpart D, Appendix D.
(COMAR 26.09.02.10 G (1))

(31) Audit Decertification.
(a) Whenever both an audit of a monitoring system and a review of the initial certification or recertification application reveal that any monitoring system should not have been certified or recertified because it did not meet a particular performance specification or the applicable provisions of 40 CFR Part 75, both at the time of the initial certification or recertification application submission and at the time of the audit, the Department shall issue a notice of disapproval of the certification status of the monitoring system.

(b) By issuing the notice of disapproval, the certification status of the monitoring system is prospectively revoked.
(COMAR 26.09.02.10 G (2))

(32) The data measured and recorded by the monitoring system may not be considered valid quality-assured data from the date of issuance of the notification of the revoked certification status.
(COMAR 26.09.02.10 G (3))

(F) Record Keeping and Reporting Requirements

(1) The CO_2 authorized account representative shall comply with all record-keeping and reporting requirements in COMAR 26.09.02.10 and the applicable record-keeping and reporting requirements under 40 CFR §75.73.
(COMAR 26.09.02.11 A)

(2) The CO_2 authorized account representative shall submit quarterly reports as described below in this section.
(COMAR 26.09.02.11 B (1))

(3) The report shall contain the CO_2 mass emissions data for the CO_2 budget unit in an electronic format, unless otherwise required by the Department, for each calendar quarter beginning with:

(a) The calendar quarter covering January 1, 2009 — March 31, 2009, for a unit that commences commercial operation before July 1, 2008; or

(b) For a unit commencing commercial operation on or after July 1, 2008, the calendar quarter corresponding to the earlier of the following dates: date of provisional certification; or applicable deadline for initial certification.

(c) If the quarter is the third or fourth quarter of 2008, reporting shall commence in the quarter covering January 1, 2009 through March 31, 2009.
(COMAR 26.09.02.11 B (2) (a)-(c))

(4) The CO_2 authorized account representative shall submit each quarterly report within 30 days following the end of the calendar quarter covered by the report and in accordance with 40 CFR Part 75, Subpart H, §75.64 and 40 CFR Part 75, Subpart G except for the opacity, NO_x and SO_2 provisions.
(COMAR 26.09.02.11 B (3))

(5) The CO_2 authorized account representative shall submit a compliance certification in support of each quarterly report. The certification shall state that:

(a) The monitoring data submitted were recorded in accordance with the applicable requirements of this chapter and 40 CFR Part 75, including the quality assurance procedures and specifications;

(b) For a unit with add-on CO_2 emissions controls and for all hours where data are substituted in accordance with 40 CFR §75.34(a)(1) , the add-on emissions controls were operating within the range of parameters listed in the quality assurance and quality control program under 40 CFR Part 75, Appendix B, and the substitute values do not systematically underestimate CO_2 emissions; and

(c) The CO_2 concentration values substituted for missing data under 40 CFR Part 75, Subpart D, do not systematically underestimate CO_2 emissions.
(COMAR 26.09.02.11 B (4) (a)-(c))

(6) The CO_2 authorized account representative of a CO_2 budget unit may submit a petition to the Department under 40 CFR §75.66 requesting approval to apply an alternative to any requirement of this chapter.
(COMAR 26.09.02.11 C)

(7) The CO_2 authorized account representative or alternate CO_2 authorized account representative of a CO_2 budget unit that burns eligible biomass as a compliance mechanism under this chapter shall report the following information for each calendar quarter:

(a) For each shipment of solid eligible biomass fuel fired at the CO_2 budget unit:

(i) Total eligible biomass fuel input, on an as-fired basis, in pounds; and

(ii) The moisture content, on an as-fired basis, as a fraction of weight;

(b) For each distinct type of gaseous eligible biomass fuel fired at the CO_2 budget unit:
(i) The density of the biogas, on an as-fired basis, in pounds per standard cubic foot; and

(ii) The moisture content of the biogas, as a fraction by total weight;

(c) For each distinct type of eligible biomass fuel fired at the CO_2 budget unit:

(i) The dry basis carbon content of the fuel type, as a fraction by dry weight;

(ii) The dry basis higher heating value, in MMBtu per dry pound;

(iii) The total dry basis eligible biomass fuel input, in pounds;

(iv) The total eligible biomass fuel heat input; and

(v) Chemical analysis, including heat value and carbon content;

(d) The total amount of CO_2 emitted from the CO_2 budget unit due to firing eligible biomass fuel, in tons, calculated as in §D(2)(b) of this regulation;

(e) The total heat input to the CO_2 budget unit due to firing eligible biomass fuel, in MMBtu, calculated below; and

(f) Description and documentation of monitoring technology and fuel sampling methodology employed, including sampling frequency.
(COMAR 26.09.02.11 D (1) (a)-(f))

(8) An owner or operator of a CO_2 budget unit shall calculate and submit on a quarterly basis the total dry weight for each distinct type of eligible biomass fired by the CO_2 budget unit during the reporting quarter:

(a) For solid eligible biomass fuel, determined as follows:

$$F_j = \sum_{i=1}^{m} (1 - M_i) x F_i$$

where:
(i) F_j = Total eligible biomass dry basis fuel input (pounds) for fuel type j;
(ii) F_i = Eligible biomass as fired fuel input (pounds) for fired shipment i;
(iii) M_i = Moisture content (fraction) for fired shipment i:
(iv) i = fired fuel shipment;

(v) j = fuel type; and
(vi) m = number of shipments.

(b) For gaseous eligible biomass fuel, as determined as follows:

$$F_j = D_j x V_j x (1 - M_j)$$

where:
(i) F_j = Total eligible biomass dry basis fuel input (pounds) for fuel type j;
(ii) D_j = Density of biogas (pounds/scf) for fuel type j;
(iii) Vj = Total volume (scf) for fuel type j;
(iv) Mj = Moisture content (fraction) for fuel type j; and
(v) j = fuel type
(COMAR 26.09.02.11 D (2) (a)-(c))

(9) The amount of CO_2 emissions that is produced from the firing of eligible biomass for any full calendar quarter, during which either no fuel other than eligible biomass is combusted or during which fuels other than eligible biomass are combusted, is determined as follows:

$$CO_2 tons = \sum_{j=1}^{n} F_j x C_j x O_j \left(\frac{44\left(\frac{g}{molCO_2}\right)}{12\left(\frac{g}{molC}\right)} \right) (0.0005)$$

where:
(a) CO_2 tons = CO_2 emissions due to firing of eligible biomass for the reporting quarter;
(b) F_j = Total eligible biomass dry basis fuel input (pounds) for fuel type j, as calculated in §D(2)(a) of this regulation;
(c) C_j = Carbon fraction (dry basis) for fuel type j;
(d) Oj = Oxidation factor for eligible biomass fuel type j, derived for solid fuels based on the ash content of the eligible biomass fired and the carbon content of this ash or for gaseous eligible biomass fuels, a default oxidation factor of 0.995 may be used;

(e) $\dfrac{44\left(\frac{g}{molCO_2}\right)}{12\left(\frac{g}{molC}\right)}$
= The number of tons of carbon dioxide that are created when one ton of carbon is combusted;
(f) 0.0005 = The number of short tons which is equal to one pound;
(g) j = Fuel type; and
(h) n = number of distinct fuel types.
(COMAR 26.09.02.11 D (3))

(10) Heat input due to firing of eligible biomass for each quarter shall be determined as follows:

(a) For each distinct fuel type:

$$H_j = F_j x HHV_j$$

where:

(i) H_j = Heat input (MMBtu) for fuel type j;

(ii) F_j = Total eligible biomass dry basis fuel input (pounds) for fuel type j;

(iii) HHV_j = Higher heating value (MMBtu/pound), dry basis, for fuel type j, as determined through chemical analysis;

(iv) j = Fuel type.

(b) For all fuel types:

$$HeatInputMMBtu = \sum_{j=1}^{n} H_j$$

where:

(i) H_j = Heat input (MMBtu) for fuel type j;

(ii) j = fuel type; and

(iii) n = number of distinct fuel types.

Fuel sampling methods and fuel sampling technology shall be consistent with the New York State Renewable Portfolio Standard Biomass Guidebook, May 2006.

(COMAR 26.09.02.11D(4) & D(5))

(11) A CO_2 budget unit shall submit to the Department the megawatt-hour value and a statement certifying that the megawatt-hour of electrical output reported reflects the total actual electrical output for all CO_2 budget units at the facility used by the independent system operator (ISO) to determine settlement resources of energy market participants.

(COMAR 26.09.02.11 E (1))

(12) A CO_2 budget unit shall report gross hourly megawatts to the Department in the same electronic data report (EDR) for gross output as submitted to the EPA Administrator, for the operating time in the hour, added for all hours in a year.

(COMAR 26.09.02.11 E (2))

(13) A CO_2 budget unit shall submit the net electrical output to the Department in accordance with this regulation. A CO_2 budget source whose electrical output is not used in the independent system operator (ISO) energy market settlement determinations shall propose a method for quantification of net electrical output.

(COMAR 26.09.02.11 E (3))

(14) For reporting of net steam output a CO_2 budget source:

(a) Selling steam shall use billing meters to determine net steam output or an alternative method to measure net steam output approved by the Department.

(b) If data for steam output is not available, the CO_2 budget source may report heat input, substituting useful steam output for steam output.
(COMAR 26.09.02.11 E (4) (a)-(b))

(15) Each CO_2 budget source shall submit an output monitoring plan with a description and diagram that include the following:

(a) If the CO_2 budget unit monitors net electric output, the diagram shall contain all CO_2 budget units and all generators served by each CO_2 budget unit and the relationship between CO_2 budget units and generators;

(b) If a generator served by a CO_2 budget unit is also served by a nonaffected unit, the nonaffected unit and its relationship to each generator shall be indicated on the diagram;

(c) The diagram shall indicate where the net electric output is measured and include all electrical inputs and outputs to and from the plant;

(d) If net electric output is determined using a billing meter, the diagram shall show each billing meter used to determine net sales of electricity and show that all electricity measured at the point of sale is generated by the CO_2 budget units;

(e) If the CO_2 budget unit monitors net thermal output, the diagram shall indicate all steam or hot water coming into the net steam system, including steam from CO_2 budget units and nonaffected units, and all exit points of steam or hot water from the net steam system;

(f) Each input and output stream shall have an estimated temperature, pressure and phase indicator, and an enthalpy in Btu per pound;

(g) The diagram of the net steam system shall identify all useful loads, house loads, parasitic loads, any other steam loads, and all boiler feedwater returns;

(h) The diagram shall represent all energy losses in the system as either usable or unusable losses;

(i) The diagram shall indicate all flow meters, temperature or pressure sensors, or other equipment used to calculate gross thermal output; and

(j) If a sales agreement is used to determine net thermal output, the diagram shall show the monitoring equipment used to determine the sales of steam.
(COMAR 26.09.02.11 F (2) (a)-(j))

(16) The description of the output monitoring system shall include:

(a) A written description of the output system and the equations used to calculate output, and, for net thermal output systems, descriptions and justifications of each useful load;

(b) A detailed description of all quality assurance and quality control activities that will be performed to maintain the output system; and

(c) Documentation supporting any output value to be used as a missing data value if there are periods of invalid output data.

(d) The missing data output value shall be either zero or an output value that is likely to be lower than a measured value and approved as part of the required monitoring plan.
(COMAR 26.09.02.11 F (3) (a)-(b))

(17) A certification statement shall be submitted by the CO_2 authorized account representative stating that either:

(a) The output monitoring system consists entirely of billing meters; or

(b) The output monitoring system meets one of the accuracy requirements for nonbilling meters.
(COMAR 26.09.02.11 G (1) (a)-(b))

(18) The billing meter shall record the electric or thermal output. Any electric or thermal output values reported shall be the same as the values used in billing for the output.
(COMAR 26.09.02.11 G (2))

(19) For nonbilling meters, either the output monitoring system shall meet an accuracy of within 10 percent of the reference value, or each component monitor for the output system shall meet an accuracy of within 3 percent of the full scale value, whichever is less stringent.
(COMAR 26.09.02.11 G (3))

(20) The system approach to accuracy shall include:

(a) A determination of how the system accuracy of 10 percent is achieved using the individual components in the system; and

(b) Data loggers and any wattmeters used to calculate the final net electric output data or any flowmeters for steam or condensate, temperature measurement devices, absolute pressure measurement devices, and differential pressure devices used for measuring thermal energy.
(COMAR 26.09.02.11 G (4) (a)-(b))

(21) If, upon testing a piece of output measurement equipment, it is determined that the output readings are not accurate to within 3 percent of the full scale value, then the equipment shall be repaired or replaced to meet that requirement.
(COMAR 26.09.02.11 G (5))

(22) Data is invalid until the output measurement equipment passes an accuracy test or is replaced with another piece of equipment that passes the accuracy test.
(COMAR 26.09.02.11 G (6))

(23) Ongoing quality assurance and quality control activities shall be performed in order to maintain the output system.
(COMAR 26.09.02.11 H (1))

(24) If billing meters are used to determine output, quality assurance and quality control activities are not required beyond what are already performed.
(COMAR 26.09.02.11 H (2))

(25) Certain types of equipment such as potential transformers, current transformers, nozzle and venture type meters, and the primary element of an orifice plate only require an initial certification of calibration and do not require periodic recalibration unless the equipment is physically changed.

(a) Pressure and temperature transmitters accompanying an orifice plate will require periodic retesting.

(b) For other types of equipment, the meter accuracy shall be recalibrated or verified at least once every 2 years, unless a consensus standard allows for less frequent calibrations or accuracy tests.

(c) For nonbilling meters, either the output monitoring system shall meet an accuracy of within 10 percent of the reference value, or each component monitor for the output system shall meet an accuracy of within 3 percent of the full scale value, whichever is less stringent.

(d) If, upon testing a piece of output measurement equipment, it is determined that the output readings are not accurate to within 3 percent of the full scale value, then the equipment shall be repaired or replaced to meet that requirement.
(COMAR 26.09.02.11 H (3) (a)-(e))

(26) Out-of-Control Periods.

(a) If, upon testing a piece of output measurement equipment, it is determined that the output readings are not accurate to the certification value, data is invalid until the output measurement equipment passes an accuracy test or is replaced with another piece of equipment that passes the accuracy test.

(b) All invalid data shall be replaced by either zero or an output value that is likely to be lower than a measured value and that is approved as part of the required monitoring plan.
(COMAR 26.09.02.11 H (4) (a)-(b))

(27) The CO_2 authorized account representative shall submit annual output reports, as follows:

(a) Data shall be sent both electronically and in hardcopy by March 1 for the immediately preceding calendar year; and
(COMAR 26.09.02.11 I (1))

(28) The annual report shall include unit level megawatt hours, all useful steam output, and a certification statement from the CO_2 authorized account representative stating the following, "I am authorized to make this submission on behalf of the owners and operators of the CO_2 budget sources or CO_2 budget units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or

imprisonment."
(COMAR 26.09.02.11 I (2))

(G) CO_2 Emission Offset Projects

(1) In order to qualify for the award of CO_2 offset allowances, the following offset projects shall satisfy all applicable requirements identified in COMAR 26.09.03 and initially commence on or after December 20, 2005:

(a) Landfill methane capture and destruction;

(b) Reduction in emissions of sulfur hexafluoride (SF_6);

(c) Sequestration of carbon due to afforestation;

(d) Reduction or avoidance of CO_2 emissions from natural gas, oil, or propane end-use combustion due to end-use energy efficiency; and

(e) Avoided methane emissions from agricultural manure management operations.
(COMAR 26.09.03.01 A (a)-(e))

ENVIRONMENTAL PROFESSIONALS
WCM

THE WCM GROUP, INC.
110 S. Bender Ave.
Humble, TX 77338

January 28, 2019

Ms. Karen G. Irons
Maryland Department of the Environment
Air & Radiation Management Administration
Air Quality Permits Program
1800 Washington Blvd., Suite 720
Baltimore, MD 21230-1720

UPS NUMBER
1Z07479R0197648755

REFERENCE: Part 70 Operating Permit and Acid Rain Permit Renewal Applications
KMC Thermo, LLC; Brandywine Power Facility
Brandywine, Prince George's County, Maryland
Part 70 Operating Permit No. 24-033-02200, AI Number 9909

Dear Ms. Irons,

On behalf of KMC Thermo, LLC (KMC Thermo), The WCM Group, Inc. is submitting three (3) copies [two (2) paper copies and one (1) electronic copy on CD] of the Part 70 Operating Permit and Acid Rain Permit renewal applications for the Brandywine Power Facility. In accordance with the letter received from the Maryland Department of the Environment dated November 5, 2018, the renewal applications are being submitted prior to the February 1, 2019 submittal due date.

KMC Thermo also requests that the CO_2 Budget Trading Program Permit (effective date July 1, 2015 through January 31, 2020) be renewed. The House Bill 935 FEIN Request Form (related to the Budget Reconciliation and Financing Act of 2003) is enclosed.

In accordance with the application shield provision pursuant to COMAR 26.11.03.01D.(1), KMC Thermo understands that Brandywine Power Facility may continue to operate in compliance with the current Part 70 Operating Permit pending issuance of the renewed Part 70 Operating Permit.

If you have any questions concerning this permit renewal application or require any additional information, please contact me at (281) 446-7070.

Sincerely,

Kerry S. Higgins
Sr. Director, Technical Services
khiggins@wcmgroup.com

KSH/llb
ENCLOSURE

cc: M. Briggs

MARYLAND DEPARTMENT OF THE ENVIRONMENT

PART 70 OPERATING PERMIT NO. 24-033-02200
RENEWAL APPLICATION

Prepared for
KMC THERMO, LLC
BRANDYWINE POWER FACILITY
Brandywine, Prince George's County, Maryland

January 2019

THE WCM GROUP, INC.
110 S. Bender Ave.
Humble, TX 77338
phone 281.446.7070 | fax 281.446.3348
wcmgroup.com

INTRODUCTION

KMC Thermo, LLC (KMC Thermo) owns and operates the Brandywine Power Facility, an existing, nominal 230 megawatt (MW) electric cogeneration facility located two (2) miles south of Brandywine in Prince George's County, Maryland. The Brandywine Power Facility consists of two (2) combined-cycle units (Emission Units 1 and 2 [EU-1 and EU-2]), a steam turbine, a diesel-fired emergency generator engine (Emission Unit 3 [EU-3]), a two (2) million gallon ultra-low sulfur diesel (ULSD) fuel oil storage tank, a recirculating cooling water system, and ancillary equipment. Each combined-cycle unit is comprised of a General Electric (GE) Frame 7EA combustion turbine (CT) and an unfired heat recovery steam generator (HRSG). Steam produced by the HRSGs is routed to a common steam turbine for generation of additional electricity. The combustion turbines fire pipeline natural gas or liquefied natural gas (LNG) as the primary fuel, and ULSD fuel oil as the backup fuel.

Facility operations are authorized under Maryland Public Service Commission (PSC) Certificate of Public Convenience and Necessity (CPCN) No. 9341 issued July 10, 2014, and Maryland Department of the Environment (MDE) Part 70 Operating Permit Number 24-033-02200 issued July 1, 2015. Note that CPCN No. 9341 incorporated all previous conditions of CPCN No. 8488. The Brandywine Power Facility was also issued a Phase II Acid Rain Permit and a CO_2 Budget Trading Program Permit. The effective dates for the Phase II Acid Rain Permit and CO_2 Budget Trading Program Permit are July 1, 2015 through January 31, 2020.

Part 70 Operating Permit Number 24-033-02200 will expire on January 31, 2020. In accordance with Code of Maryland Regulations Title 26, Subtitle 11, Chapter 03 (Permits, Approvals, and Registration - Part 70 Permits), Regulation .02B(3)(b) [COMAR 26.11.03.02B.(3)(b)] and Part 70 Operating Permit Number 24-033-02200 Section II, General Condition No. 5, a complete application for renewal of the Part 70 Operating Permit is to be submitted at least twelve (12) months prior to the expiration of the permit (i.e., no later than January 31, 2019). This application satisfies the permit renewal application submittal requirement.

CPCN No. 9341 was amended by the Maryland PSC on April 5, 2017 to remove the 51 megawatt (MW) minimum load limit for the combustion turbines (EU-1 and EU-2). The 51 MW minimum load limit was replaced with the requirement (except for start-up and shutdown periods, and during black start events) that "…each combustion turbine unit shall operate only when the unit, for natural gas or LNG firing, is in DLN premix mode, or when firing ULSD fuel oil, water injection is engaged." The April 2017 amendment affects the wording of the Fact Sheet, Operational Limitations, G3 and Section IV, [1.1,G3, 1.4,G3 and 1.5,G,(j) the current Part 70 Operating Permit. As specified in the email from Mr. Bill Paul to Mr. Mark Briggs dated June 26, 2017 (see Attachment A), changes to the Part 70 Operating Permit to reflect the April 2017 amendment are to be incorporated into the

permit during the renewal process. Suggested redline changes to the applicable sections of the Part 70 Operating Permit are provided as Attachment B.

The following completed MDE forms are provided in the Forms section of this application:

- House Bill 935 FEIN Request Form;
- Part 70 Permit Application for Renewal;
- Renewal Title V Application Insignificant Activities List; and
- Renewal Title V Checklist.

Copies of the most recent (i.e., calendar year 2017) Emission Certification Report and Annual Compliance Certification Report are provided in Attachments C and D, respectively. An Acid Rain Permit Renewal Application is provided as Attachment E. Note that there has been no change to the process flow diagram or facility plot plan since submittal of the initial application so submittal of these documents is not required.

KMC Thermo has made an effort to ensure that this application is complete as filed and has submitted the application prior to the January 31, 2019 deadline. Pursuant to COMAR 26.11.03.01D, KMC Thermo understands that, following submittal of a timely and complete application for permit renewal, Brandywine Power Facility may continue to operate in compliance with the current Part 70 Operating Permit pending issuance of the renewed Part 70 Operating Permit. If any additional information is needed, please advise as soon as possible so that the requested data may be provided in a timely manner. In accordance with COMAR 26.11.03.02C.(3), KMC Thermo understands that it will have a reasonable time as set by MDE to respond to any requests for additional information while retaining the application shield provision.

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ATTACHMENTS

A - EMAIL CORRESPONDENCE

B - SUGGESTED REDLINE CHANGES

C - 2017 EMISSIONS CERTIFICATION CHECKLIST

D - 2017 ANNUAL COMPLIANCE CERTIFICATION REPORT

E - ACID RAIN PRMIT RENEWAL APPLICATION

HOUSE BILL 935 FEIN REQUEST FORM

MARYLAND DEPARTMENT OF THE ENVIRONMENT

1800 Washington Boulevard • Suite 720 • Baltimore, Maryland 21230-1720
410-537-3000 • 800-633-6101 • http://www.mde.maryland.gov

Air and Radiation Administration • Air Quality Permits Program

Budget Reconciliation and Financing Act of 2003
(Commonly referred as Maryland House Bill 935)

On July 1, 2003, House Bill 935, Chapter 203 amended § 1-203 of the Environment Article, Annotated Code of Maryland, as follows:

Section 1-203(b).
(1) A license or permit is considered renewed for purposes of this subsection if the license or permit is issued by a unit of State government to a person for the period immediately following a period for which the person previously possessed the same or a substantially similar license.
(2) Before any license or permit may be renewed under this article, **the issuing authority shall verify through the office of the Comptroller (emphasis added)** that the applicant has paid all undisputed taxes and the unemployment insurance contributions payable to the Comptroller or the Secretary of Labor, Licensing, and Regulation or that the applicant has provided for payment in a manner satisfactory to the unit responsible for collection.

In order for the Maryland Department of the Environment (MDE) to verify this compliance, we would need you to provide the following information before we can process or issue your renewal license, permit, or certification:

Current MDE License/Permit No.: 24-033-02200

Name of Licensee or Permit Holder: KMC Thermo, LLC

Address: 16400 Mattawoman Drive

Brandywine, Maryland 20613

Contact Name: Michael Fulcher **Title:** Asset Manager

Contact Telephone Number: 301-782-4000

Privacy Act Notice: This Notice is provided pursuant to the Federal Privacy Act of 1974, 5 U.S.C. § 552a. Disclosure of your Social Security or Federal Tax Identification on this form is mandatory pursuant to the provisions of § 1-203 (2003) of Environment Article, Annotated Code of Maryland, which requires MDE to verify that an applicant for a permit or license has paid all undisputed taxes and unemployment insurance. Social Security and Federal Tax Identification Nos. will not be used for any purposes other than those described in this Notice.

Federal Employer Identification Number (FEIN): 45-0470628

Certification: I certify that the above information is true and correct to the best of my knowledge.

Signature

1-25-2019
Date

Complete and return this form to Sena Harlley at the above address. If you have any questions, please contact Ms. Harlley at (410) 537-3251.

PART 70 PERMIT APPLICATION FOR RENEWAL

MARYLAND DEPARTMENT OF THE ENVIRONMENT
1800 Washington Boulevard ● Baltimore MD 21230
(410) 537-3000 ● 1-800-633-6101 ● http://www.mde.state.md.us

PART 70 PERMIT APPLICATION FOR RENEWAL

AIR AND RADIATION ADMINISTRATION

Facilities required to obtain a Part 70 permit under COMAR 26.11.03.01 must complete and return this form. Applications are incomplete unless all applicable information required by COMAR 26.11.03.03 and 26.11.03.13 is supplied. Failure to supply additional information required by the Department to enable it to act on the application may result in loss of the application shield and denial of this application.

Owner and Operator:

Name of Owner or Operator: KMC Thermo, LLC		
Street Address: 1111 Fannin Street, 11th Floor		
City: Houston	State: Texas	Zip Code: 77002
Telephone Number 301-782-4000		Fax Number 301-782-4004

Facility Information:

Name of Facility: Brandywine Power Facility		
Street Address: 16400 Mattawoman Drive		
City: Brandywine	State: Maryland	Zip Code: 20613-8089
Plant Manager: Mark Briggs	Telephone Number: 301-782-4000	Fax Number: 301-782-4004
24-Hour Emergency Telephone Number for Air Pollution Matters: 301-782-4000		

List, on a separate page, the names and telephone numbers of other facility owners and persons with titles. Not Applicable

SECTION 1. CERTIFICATION STATEMENTS

1. Compliance Status with Applicable Enhanced Monitoring and Compliance Certification Requirements

The emissions units identified in this application are in compliance with applicable enhanced monitoring and compliance certification requirements.

2. Certification of Current Compliance with All Applicable Federally Enforceable Requirements

Except for the requirements identified in Section 7 of this application, for which compliance is not achieved, I hereby certify, based on information and belief formed after reasonable inquiry, that the facility is currently in compliance with all applicable federally enforceable requirements and agree that the facility will continue to comply with those requirements during the permit term.

You must complete a Section 7 form for each non-complying emissions unit.

3. Statement of Compliance with Respect to All New Applicable Requirements Effective During the Permit Term

I hereby state, based on information and belief formed after reasonable inquiry, that the facility agrees to meet, in a timely manner, all applicable federally enforceable requirements that become effective during the permit term, unless a more detailed schedule is expressly required by the applicable requirement.

4. Risk Management Plan Compliance

I hereby certify that, based on information and belief formed after reasonable inquiry, that a Risk Management Plan as required under □112(r) of the Clean Air Act:

[ ] has been submitted;

[ ] will be submitted at a future date; or

[✓] does not need to be submitted.

5. Statement of Truth, Accuracy, and Completeness

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

RESPONSIBLE OFFICIAL:

X _____ 1-25-2019

SIGNATURE DATE

Michael Fulcher

PRINTED NAME

Asset Manager

TITLE

SECTION 2. FACILITY DESCRIPTION SUMMARY

1. Major Activities of Facility

Briefly describe the major activities, including the applicable SIC Code(s) and end product(s).

KMC Thermo, LLC operates a nominal 230-megawatt cogeneration facility located two (2) miles south of Brandywine, MD in Prince Georges County. The facility is a combined-cycle facility comprised of two (2), General Electric 7EA combustion turbines (CTs), two (2) unfired heat recovery steam generators (HRSGs) and one (1) steam turbine. The combustion turbines fire pipeline natural gas or liquified natural gas (LNG) as the primary fuel, and ULSD fuel oil as the backup fuel. The applicable SIC code for the facility is 4911 - Electric Services.

2. Facility-Wide Emissions

A. This facility is required to obtain a Part 70 Operating Permit because it is: Check appropriate box:

- ☑ Actual Major
- ☐ Potential Major
- ☐ Solid Waste Incineration Unit Requiring Permit Under § 129(e) of CAA

B. List the actual facility-wide emissions below: tons per year, 2017

PM10 18.9 NOx 78.7 VOC 6.0 SOx 1.7 CO 43.2 HAPs 2.9

3. Include With the Application:

Flow Diagrams showing all emissions units, emission points, and control devices; No change. Therefore, submittal not required.
Emissions Certification Report (copy of the most recent submitted to the Department.) See Attachment A

SECTION 3A. EMISSIONS UNIT DESCRIPTIONS

1. Emissions Unit No.: EU-1 (CT/HRSG Unit 1)

1a. Date of installation (month/year): June 1996

2. MDE Registration No.:(if applicable)

033-2200-5-0844

3. Detailed description of the emissions unit, including all emission point(s) and the assigned number(s):

Combined cycle cogeneration unit consisting of one (1) GE model PG7111EA combustion turbine (CT-1) and one (1) unfired heat recovery steam generator (HRSG-1). CT-1 utilizes pipeline natural gas (NG) or liquified natural gas (LNG) as its primary fuel source with ULSD fuel oil serving as backup fuel. CT-1 is equipped with dry low NOx (DLN) combustors to reduce formation of NOx when firing NG or LNG. NOx formation is reduced by water injection when CT-1 is fired with fuel oil.

CT-1 exhaust gases are discharged to the atmosphere via HRSG-1 exhaust stack (Emission Point EP-1).

4. Federally Enforceable Limit on the Operating Schedule for this Emissions Unit:

General Reference: Part 70 Operating Permit No. 24-033-0220, Section IV, Item 1.1 G (CPCN #9341 Condition 9)

Continuous Processes: 2,400 turbine hours (CT-1 + CT-2) on a rolling 12-month basis when firing on ULSD fuel oil.

Batch Processes: _____ hours/batch _____ batches/day

_____ days/year

5. Fuel Consumption:

	Type(s) of Fuel	% Sulfur	Annual Usage (specify units)
1.	Natural Gas (NG)	< 0.001	8,602.2 x 10^6 cu. ft. (max)
2.	Liquefied Natural Gas (LNG	<0.001	9,022.4 x 10^6 cu. ft. (max)
3.	ULSD Fuel Oil	0.0015	19,236.0 x 10^3 gal. (max)

6. Emissions in Tons:

A. Actual Major: X Potential Major: _____ (note: before control device)

B. Actual Emissions: NOx 34.6 SOx 0.8 VOC 2.8 PM10 8.7 HAPs 1.3

SECTION 3A. EMISSIONS UNIT DESCRIPTIONS

1. Emissions Unit No.: EU-2 (CT/HRSG Unit 2)

1a. Date of installation (month/year): June 1996

2. MDE Registration No.:(if applicable)
033-2200-5-0845

3. Detailed description of the emissions unit, including all emission point(s) and the assigned number(s):
Combined cycle cogeneration unit consisting of one (1) GE model PG7111EA combustion turbine (CT-2) and one (1) unfired heat recovery steam generator (HRSG-2). CT-2 utilizes pipeline natural gas (NG) or liquified natural gas (LNG) as its primary fuel source with ULSD fuel oil serving as backup fuel. CT-2 is equipped with dry NOx (DLN) combustors to reduce formation of NOx when firing NG or LNG. NOx formation is reduced by water injection when CT-2 is fired with fuel oil.

CT-2 exhaust gases are discharged to the atmosphere via HRSG-2 exhaust stack (Emission Point: EP-2).

4. Federally Enforceable Limit on the Operating Schedule for this Emissions Unit:
General Reference: Part 70 Operating Permit No. 24-033-0220, Section IV, Item 1.1 G (CPCN #9341 Condition 9)

Continuous Processes: 2,400 Turbine hours (CT-1 + CT-2) on a rolling 12-month basis when firing on ULSD fuel oil.

Batch Processes: _____ hours/batch _____ batches/day

_____ days/year

5. Fuel Consumption:

Type(s) of Fuel	% Sulfur	Annual Usage (specify units)
1. Natural Gas (NG)	<0.001	8,602.2 x 10^6 cu.ft. (max)
2. Liquefied Natural Gas (LNG)	<0.001	9,022.4 x 10^6 cu.ft. (max)
3. ULSD Fuel Oil	0.0015	19,236.0 x 10^3 gal. (max)

6. Emissions in Tons:

A. Actual Major: X Potential Major: _____ (note: before control device)

B. Actual Emissions: NOx 43.6 SOx 0.9 VOC 3.2 PM10 10.2 HAPs 1.6

SECTION 3A. EMISSIONS UNIT DESCRIPTIONS

1. Emissions Unit No.: EU-3 (Emergency Generator)

1a. Date of installation (month/year): May 2015

2. MDE Registration No.:(if applicable)
033-2200-9-1465

3. Detailed description of the emissions unit, including all emission point(s) and the assigned number(s):
Emergency generator consisting of one (1) Caterpiller Model C175-20 diesel engine, with a 5.3 liter displacement per cylinder, capable of producing 4,000 kilowatts of electricity. It is used soley for starting a designated combustion turbine during black start events. As such, it will be operated as an emergency generator and will operate for less than 100 hours per year for maintenance and readiness testing. Per NSPS Subpart IIII, the unit is fired exclusively on ultra low-sulfur diesel fuel.

The emergency generator exhaust gases are discharged to the atmosphere via an exhaust stack (Emission Point: EP-3).

4. Federally Enforceable Limit on the Operating Schedule for this Emissions Unit:
General Reference: Part 70 Operating Permit No. 24-033-0220, Section IV, Item 2.1 E3 (CPCN #9341 Condition 17)

Continuous Processes:

Batch Processes: <100 hours/ year _____ batches/day

_____ days/year

5. Fuel Consumption:

	Type(s) of Fuel	% Sulfur	Annual Usage (specify units)
1.	ULSD Fuel Oil	0.0015	27,460 gallons (based on 100 annual operating hours)
2.			
3.			

6. Emissions in Tons:

A. Actual Major: _____ Potential Major: _____ (note: before control device)

B. Actual Emissions: NOx 0.44 SOx 0.00 VOC 0.00 PM10 0.02 HAPs 0.00

SECTION 3B. CITATION TO AND DESCRIPTION OF APPLICABLE FEDERALLY ENFORCEABLE REQUIREMENTS

Emissions Unit No.: EU-1 and EU-2 **General Reference:** COMAR 26.11.09.05A and A(3)

Briefly describe the Emission Standard/Limit or Operational Limitation:
Discharge of emissions, other than water in an uncombined form, visible to human observers is prohibited. Regulation does not apply to emissions during the building of a new fire, cleaning of fires, soot blowing, startup, or occasional cleaning of control equipment if visible emissions (VE) do not exceed 40% opacity and VE do not occur for more than six (6) consecutive min. in any 60 min.
Part 70 Operating Permit No. 24-033-02200, Section IV, 1.1, A

Permit Shield Request: Yes

Compliance Demonstration:

Check appropriate reports required to be submitted:
- ☐ Quarterly Monitoring Report:_____
- ☑ Annual Compliance Certification:_____
- ☑ Semi-Annual Monitoring Report: _____

Methods used to demonstrate compliance: Visible emission evaluations, if required

Monitoring: Reference COMAR 26.11.03.06C Describe: Properly maintain CTs, maintain an operations manual and preventative maintenance plan, verify no visible emissions (VE) during ULSD fuel oil combustion. Perform an EPA Reference Method (RM) 9 test for 6 minute period once for each 168 hours that the CTs burn ULSD fuel oil. If VE are observed, inspect CT operations, perform all necessary adjustments to the CTs within 48 hours to eliminate VE, document in writing results of CT inspections and/or repairs. If repairs have not eliminated VE within 48 hours, perform an EPA RM 9 test daily for 18 minutes until VE are eliminated.

Testing: Reference Not Applicable Describe: None

Record Keeping: Reference COMAR 26.11.03.06C(5)(g) Describe: Maintain a log of CT maintenance that relates to CT combustion performance. Maintain a log of VE observations performed on site for five (5) years.

Reporting: Reference COMAR 26.11.03.06C Describe: Report incidents of VE in accordance with Part 70 Operating Permit No. 24-033-02200, Condition 4 of Section III, Report of Excess Emissions and Deviations.

Frequency of submittal of the compliance demonstration: Not Applicable

SECTION 3B. CITATION TO AND DESCRIPTION OF APPLICABLE FEDERALLY ENFORCEABLE REQUIREMENTS

Emissions Unit No.: EU-1 and EU-2 **General Reference:** COMAR 26.11.09.07A(2b), CPCN No. 9341, Condition No. 8 and NSPS 40 CFR 60.333

Briefly describe the Emission Standard/Limit or Operational Limitation:

Sulfur content of distillate fuel oil shall not exceed to 0.3 weight percent [COMAR 26.11.09.07A(2)(b)] and 0.0015 weight percent [CPCN No. 9341, Condition No. 8]. Sulfur content of any fuel shall not exceed 0.8 weight percent [NSPS 40 C§FR 60.333]. Compliance with the more restrictive CPCN ULSD fuel oil sulfur content limit is the basis for demonstrating compliance with the applicable COMAR and NSPS fuel oil sulfur content limits. Part 70 Operating Permit No. 24-033-02200, Section IV, 1.1, B1

Permit Shield Request: Yes

Compliance Demonstration:

Check appropriate reports required to be submitted:

- ☑ Quarterly Monitoring Report:
- ☑ Annual Compliance Certification:
- ☑ Semi-Annual Monitoring Report:

Methods used to demonstrate compliance: Fuel sulfur content analysis

Monitoring: Reference CPCN No. 8488, Cnd. 8 Describe: Perform sampling and analysis of as fired fuel oil in accordance with 40 CFR Part 75, Appendix D procedures. No monitoring is required with respect to the NSPS 40 CFR 60.333 sulfur limit for NG or LNG since gaseous fuels used meet the definition of natural gas in 40 CFR §60.331(i).

Testing: Reference Not Applicable Describe: None

Record Keeping: Reference COMAR 26.11.03.06C Describe: Maintain records of fuel analysis.

Reporting: Reference Not Applicable Describe: None

Frequency of submittal of the compliance demonstration: Quarterly

SECTION 3B. CITATION TO AND DESCRIPTION OF APPLICABLE FEDERALLY ENFORCEABLE REQUIREMENTS

Emissions Unit No.: EU-1 and EU-2 **General Reference:** CPCN Case No. 9341

Briefly describe the Emission Standard/Limit or Operational Limitation: Excluding periods of startup, shutdown and malfunction, CT outlet CO emissions shall not exceed 59 lb/hr burning NG, 59 lb/hr burning LNG and 71 lb/hr burning ULSD fuel oil, CT outlet PM/PM10 shall not exceed 7 lb/hr burning NG or LNG and 15 lb/hr burning fuel oil, CT outlet VOC emissions shall not exceed 2 lb/hr burning NG or LNG, and 5 lb/hr burning ULSD fuel oil, CT outlet NOx emission shall not exceed 35 lb/hr burning NG, 39 lb/hr burning LNG and 239 lb/hr burning ULSD fuel oil, CT outlet SO (as SO2) emissions shall not exceed 29 lb/hr burning NG or LNG and 54 lb/hr burning ULSD fuel oil and CT outlet sulfuric acid mist emissions shall not exceed 3 lb/hr burning NG or LNG and 6 lb/hr burning ULSD fuel oil.

Permit Shield Request: Yes

Part 70 Operating Permit No. 24-033-02200, Section IV, 1.1, B2, B3, C2, D, E, & F; CPCN No. 9341, Condition 5.

Compliance Demonstration:

Check appropriate reports required to be submitted:

- ☐ Quarterly Monitoring Report:_____
- ☑ Annual Compliance Certification:_____
- ☑ Semi-Annual Monitoring Report: _____

Methods used to demonstrate compliance: Stack Testing, if required by MDE

Monitoring: Reference Not Applicable Describe: None

Testing: Reference CPCN No. 9341, Cnd. 12 Describe: If requested by MDE.

Record Keeping: Reference Not Applicable Describe: None

Reporting: Reference Not Applcable Describe: None

Frequency of submittal of the compliance demonstration: Not Applicable

SECTION 3B. CITATION TO AND DESCRIPTION OF APPLICABLE FEDERALLY ENFORCEABLE REQUIREMENTS

Emissions Unit No.: EU-1 and EU-2 **General Reference:** 40 CFR Parts 72 and 75

Briefly describe the Emission Standard/Limit or Operational Limitation: Acid Rain Program (ARP) requirements. Includes requirement to obtain SO2 allowances equal to actual emissions each year. ARP also includes continuous emissions monitoring systems (CEMS) requirements for NOx and O2. Quarterly electronic reporting of emissions and operations data required. ARP NOx reduction requirements are not applicable since EU-1 and EU-2 do not burn coal.

Part 70 Operating Permit No. 24-033-02200, Section IV, 1.1, B5, Phase II Acid Rain Requirements.

Permit Shield Request: Yes

Compliance Demonstration:

Check appropriate reports required to be submitted:

- ☑ Quarterly Monitoring Report:_____
- ☑ Annual Compliance Certification:_____
- ☑ Semi-Annual Monitoring Report: _____

Methods used to demonstrate compliance: 40 CFR Part 75 Procedures

Monitoring: Reference 40 CFR Part 75 Describe: CEMS for NOx/O2, Appendix D procedures for SO2 Appendix F procedures for NOx, SO2, CO2 and heat input and Appendix G procedures for CO2.

Testing: Reference 40 CFR Part 75 Describe: CEMS and fuel flow meter QA/QC procedures per Appendices B and D to 40 CFR 75.

Record Keeping: Reference 40 CFR Part 75 Describe: Per 40 CFR Part 75, Subpart F.

Reporting: Reference 40 CFR Part 75 Describe: Per 40 CFR Part 75, Subpart G; Quarterly electronic reporting.

Frequency of submittal of the compliance demonstration: Annual

SECTION 3B. CITATION TO AND DESCRIPTION OF APPLICABLE FEDERALLY ENFORCEABLE REQUIREMENTS

Emissions Unit No.: EU-1 and EU-2 **General Reference:** 40 CFR 97 Subpart CCCCC

Briefly describe the Emission Standard/Limit or Operational Limitation:
During the control period of each year the Permittee is required to hold a compliance account of SO2 allowances available for compliance deductions in accordance with 40 CFR §97.606(c), as of the SO2 allowance transfer date, at least equal to the Permittee's actual SO2 emissions for the control period. A control period begins January 1 and ends on December 31 of each year.

Part 70 Operating Permit No. 24-033-02200, Section IV, 1.1, B6.

Permit Shield Request: Yes

Compliance Demonstration:

Check appropriate reports required to be submitted:

- ☑ Quarterly Monitoring Report:_____
- ☑ Annual Compliance Certification:_____
- ☑ Semi-Annual Monitoring Report: _____

Methods used to demonstrate compliance: 40 CFR Part 75 Procedures

Monitoring: Reference 40 CFR Part 75 Describe: 40 CFR 75 Appendix D follow procedures for measuring fuel flow and sulfur content of fuel to determine SO2 emissions.

Testing: Reference 40 CFR Part 75 Describe: CEMS and fuel flow meter QA/QC procedures per Appendices B and D to 40 CFR 75.

Record Keeping: Reference 40 CFR Part 75 Describe: Per 40 CFR Part 75, Subpart F.

Reporting: Reference 40 CFR Part 75 Describe: Per 40 CFR Part 75, Subpart G, Quarterly electronic reporting.

Frequency of submittal of the compliance demonstration: Quarterly

SECTION 3B. CITATION TO AND DESCRIPTION OF APPLICABLE FEDERALLY ENFORCEABLE REQUIREMENTS

Emissions Unit No.: EU-1 and EU-2 **General Reference:** COMAR 26.11.09.08G(2), CPCN No. 9341, Condition No. 4 and NSPS 40 CFR §60.332

Briefly describe the Emission Standard/Limit or Operational Limitation: Excluding periods of startup, shutdown, malfunction, and black start, CT outlet NOx concentration shall not exceed 9 parts per million by volume on a dry basis corrected to 15% oxygen (ppmvd@15% O2) burning NG, 10 ppmvd@15% O2 burning LNG and 54 ppmvd@15% O2 burning ULSD fuel oil. Excluding these periods, CT outlet NOx concentration shall not exceed 144 ppmvd@15% O2 burning NG or LNG and 101 ppmvd15% O2 burning ULSD fuel oil. Excluding periods of startup, shutdown and malfunction CT outlet NOx concentration shall not exceed 42 ppmvd@15% O2 burning NG or LNG and 65 ppmvd@15% O2 burning fuel oil. Compliance with more restrictive CPCN NOx emission limit is the basis demonstrating compliance with the applicable COMAR and NSPS limits.

Permit Shield Request: Yes

Part 70 Operating Permit No. 24-033-02200, Section IV, Item 1.1 C1, C4, & C5

Compliance Demonstration:

Check appropriate reports required to be submitted:

- ☑ Quarterly Monitoring Report:_____
- ☑ Annual Compliance Certification:_____
- ☑ Semi-Annual Monitoring Report: _____

Methods used to demonstrate compliance: NOx/O2 CEMS

Monitoring: Reference CPCN No. 9341, Cnd. 13 Describe: NOx/diluent (O2) CEMS is used to continuously monitor NOx emissions. NOx/O2 CEMS monitoring is conducted in accordance with 40 CFR Part 75 including the QA/QC requirements of 40 CFR Part 75, Appendix B.

Testing: Reference CPCN No. 9341, Cnd. 12 Describe: If requested by MDE.

Record Keeping: Reference COMAR 26.11.03.06C Describe: Maintain records of NOx/O2 CEMS data.

Reporting: Reference CPCN No. 9341, Cnd. No. 14 Describe: Submit quarterly summaries of NOx/O2 CEMS data as described in CPCN No. 9341, Condition No. 14.

Frequency of submittal of the compliance demonstration: Quarterly

SECTION 3B. CITATION TO AND DESCRIPTION OF APPLICABLE FEDERALLY ENFORCEABLE REQUIREMENTS

Emissions Unit No.: EU-1 and EU-2 **General Reference:** CPCN Case No. 9341

Briefly describe the Emission Standard/Limit or Operational Limitation: Excluding periods of startup, shutdown, malfunction or PJM system emergency or black start events, annual facility wide NOx (as NO2) emissions shall be limited to no more than 437 tons on a rolling 12 months basis.

Under no circumstances shall annual facility-wide NOx (as NO2) emissions exceed 518 tons on a rolling month basis.

Part 70 Operating Permit No. 24-033-02200, Section IV, 1.1, C3; CPCN No. 9341 Condition 6.

Permit Shield Request: Yes

Compliance Demonstration:

Check appropriate reports required to be submitted:

- ☑ Quarterly Monitoring Report:_____
- ☑ Annual Compliance Certification:_____
- ☑ Semi-Annual Monitoring Report: _____

Methods used to demonstrate compliance: NOx/O2 CEMS

Monitoring: Reference CPCN No. 9341, Cnd. 13 Describe: NOx/diluent (O2) CEMS is used to continuously monitor NOx emissions. NOx/O2 CEMS monitoring is consuxcted in accordance with 40 CFR Part 75 including the QA/QC requirements of 40 CFR Part 75, Appendix B.

Testing: Reference Not Applicable Describe: None

Record Keeping: Reference COMAR 26.11.03.06C Describe: Maintain records of NOx/O2.

Reporting: Reference CPCN No. 9341, Cnd.14 Describe: Submit quarterly summaries of NOx/O2 CEMS data as described in CPCN No. 9341, Condition No. 14.

Frequency of submittal of the compliance demonstration: Annual

SECTION 3B. CITATION TO AND DESCRIPTION OF APPLICABLE FEDERALLY ENFORCEABLE REQUIREMENTS

Emissions Unit No.: EU-1 and EU-2 **General Reference:** 40 CFR 97 Subpart AAAAA

Briefly describe the Emission Standard/Limit or Operational Limitation:
The Permittee is required to hold an account of NOx allowances available for compliance deductions in accordance with 40 CFR §97.406, as of the NOx allowance transfer date (March 31), at least equal to the Permittee's actual NOx emissions for the control period. A control period begins January 1 and ends on December 31 of each year.

Part 70 Operating Permit No. 24-033-02200, Section IV, 1.1, C6.

Permit Shield Request: Yes

Compliance Demonstration:

Check appropriate reports required to be submitted:

- ☑ Quarterly Monitoring Report:
- ☑ Annual Compliance Certification:
- ☑ Semi-Annual Monitoring Report:

Methods used to demonstrate compliance: NOx/O2 CEMS

Monitoring: Reference 40 cfr 97.430 Describe: NOx/diluent (O2) CEMS is used to continuously monitor NOx emissions. NOx/O2 CEMS monitoring is conducted in accordance with 40 CFR Part 75, Subpart H and the monitoring requirements of 40 CFR 97.430.

Testing: Reference Not Applicable Describe: None

Record Keeping: Reference 40 CFR 97.434 Describe: Maintain records of NOx/O2 CEMS data and related information for a period of not less than 5 years.

Reporting: Reference 40 CFR 97.434 Describe: Submit quarterly reports of NOx emissions in lb/hr during the control period and total quarterly and control period NOx emissions in tons to EPA and the NATS Administrator by the 30th of the month following each calendar quarter in which reports are required in accordance with 40 CFR Part 75, Subpart H and 40 CFR Part 97.434(d).

Frequency of submittal of the compliance demonstration: Quarterly

SECTION 3B. CITATION TO AND DESCRIPTION OF APPLICABLE FEDERALLY ENFORCEABLE REQUIREMENTS

Emissions Unit No.: EU-1 and EU-2 **General Reference:** 40 CFR 97 Subpart BBBBB

Briefly describe the Emission Standard/Limit or Operational Limitation:
The Permittee is required to hold an account of NOx allowances available for compliance deductions in accordance with 40 CFR §97.506, as of the NOx allowance transfer date (March1), at least equal to the Permittee's actual NOx emissions for the control period. A control period begins May 1 and ends on Septemberr 30 of each year.

Part 70 Operating Permit No. 24-033-02200, Section IV, 1.1, C6.

Permit Shield Request: Yes

Compliance Demonstration:

Check appropriate reports required to be submitted:

- ☑ Quarterly Monitoring Report:_____
- ☑ Annual Compliance Certification:_____
- ☑ Semi-Annual Monitoring Report: _____

Methods used to demonstrate compliance: NOx/O2 CEMS

Monitoring: Reference 40 CFR 97.530 Describe: NOx/diluent (O2) CEMS is used to continuously monitor NOx emissions. NOx/O2 CEMS monitoring is conducted in accordance with 40 CFR Part 75, Subpart H and the monitoring requirements of of 40 CFR 97.530.

Testing: Reference Not Applicable Describe: None

Record Keeping: Reference 40 CFR 97.534 Describe: Maintain records of NOx/O2 CEMS data and related information for a period of not less than 5 years.

Reporting: Reference 40 CFR 97.534 Describe: Submit quarterly reports of NOx emissions in lb/hr during the control period and total quarterly and control period NOx emissions in tons to EPA and the Administrator by the 30th of the month following each calendar quarter in which reports are required in accordance with 40 CFR Part 75, Subpart H and 40 CFR Part 97.534(d),

Frequency of submittal of the compliance demonstration: Quarterly

SECTION 3B. CITATION TO AND DESCRIPTION OF APPLICABLE FEDERALLY ENFORCEABLE REQUIREMENTS

Emissions Unit No.: EU-1 and EU-2 **General Reference:** CPCN Case No. 9341

Briefly describe the Emission Standard/Limit or Operational Limitation: Only NG or LNG shall be used to generate electricity unless fuel delivery is interrupted or curtailed, in which case ULSD fuel oil may be burned provided NOx emisions when burning ULSD fuel oil do not exceed 143 tons per year (tpy). If there is a PJM emergency or black start event and NG is unavailable, ULSD fuel oil may be burned with NOx emissions during ULSD fuel oil burning above the 143 tpy limit. Under no circumstance may the facility burn ULSD fuel oil for more than 2,400 turbine hours per year. A year is defined as November 1 through October 31.

Part 70 Operating Permit No. 24-033-02200, Section IV, 1.1, G1;, CPCN No. 9341 Condition 9.

Permit Shield Request: Yes

Compliance Demonstration:

Check appropriate reports required to be submitted:

- ☑ Quarterly Monitoring Report:_____
- ☑ Annual Compliance Certification:_____
- ☑ Semi-Annual Monitoring Report: _____

Methods used to demonstrate compliance: NOx/O2 CEMS and CT Instrumentation

Monitoring: Reference CPCN No. 9341, Cnd. 13 Describe: NOx/diluent (O2) CEMS is used to continuously monitor NOx emissions. NOx/O2 CEMS monitoring is conducted in accordance with 40 CFR Part 75 including the QA/QC requirements of 40 CFR Part 75, Appendix B. Hourly monitoring of CT operating hours when burning distillate fuel oil.

Testing: Reference Not Applicable Describe: None

Record Keeping: Reference COMAR 26.11.03.06C Describe: Maintain records of NOx/O2 CEMS data and CT operating hours when burning distillate fuel oil.

Reporting: Reference CPCN No. 9341, Cnd. 14 Describe: Submit quarterly summaries of NOx/O2 CEMS data and CT operating hours when burning ULSD fuel oil.

Frequency of submittal of the compliance demonstration: Annual

SECTION 3B. CITATION TO AND DESCRIPTION OF APPLICABLE FEDERALLY ENFORCEABLE REQUIREMENTS

Emissions Unit No.: EU-1 and EU-2 **General Reference:** CPCN Case No. 9341

Briefly describe the Emission Standard/Limit or Operational Limitation: Excluding periods of startup and shutdown periods, and black start events, each combustion turbine unit shall operate only when the unit, firing either natural gas or LNG, is in DLN premix mode, or when firing ULSD fuel oil, water injection is engaged.

Part 70 Operating Permit No. 24-033-02200, Section IV, 1.1, G3;, CPCN No. 9341 Condition 7.

Permit Shield Request: Yes

Compliance Demonstration:

Check appropriate reports required to be submitted:

- ☑ Quarterly Monitoring Report:_____
- ☑ Annual Compliance Certification:_____
- ☑ Semi-Annual Monitoring Report: _____

Methods used to demonstrate compliance: CT Instrumentation

Monitoring: Reference CPCN No. 9341, Cnd. 14 Describe: Hourly monitoring of electricity produced by each CT.

Testing: Reference Not Applicable Describe: None

Record Keeping: Reference COMAR 26.11.03.06C Describe: Maintain records of electricity produced for 5 years.

Reporting: Reference CPCN No. 9341, Cnd.14 Describe: Submit quarterly summaries of the megawatts of electricity produced by each turbine on an hourly basis.

Frequency of submittal of the compliance demonstration: Quarterly

SECTION 3B. CITATION TO AND DESCRIPTION OF APPLICABLE FEDERALLY ENFORCEABLE REQUIREMENTS

Emissions Unit No.: EU-3 **General Reference:** COMAR 26.11.09.05E

Briefly describe the Emission Standard/Limit or Operational Limitation: A discharge of emissions from the emergency generator with an opacity greater than 10 percent while idling is not allowed. A discharge of emissions from the emergency generator with an opacity greater than 40 percent while operating at other than idle is not allowed.

Part 70 Operating Permit No. 24-033-02200, Section IV, 2.1, A;, CPCN No. 9341 Condition 16.

Permit Shield Request: Yes

Compliance Demonstration:

Check appropriate reports required to be submitted:

- ☐ Quarterly Monitoring Report:_____
- ☑ Annual Compliance Certification:_____
- ☐ Semi-Annual Monitoring Report: _____

Methods used to demonstrate compliance:

Monitoring: Reference COMAR 26.11.03.06C Describe: Properly operate and maintain the engine in a manner to minimize visible emissins. Maintain an operations manual and preventive maintenance plan

Testing: Reference Not Applicable Describe: None

Record Keeping: Reference COMAR 26.11.03.06C Describe: Maintain records of the preventive maintenance that relates to the combustion precess performed on the engine for at least 5 years and make the records available to MDE upon request.

Reporting: Reference CCOMAR 26.11.03.06C Describe: Report incidents of visible emissions in accordance with Part 70 Operating Permit No. 24-033-02200, Condition 4 of Section III, Report of Excess Emissions and Deviations.

Frequency of submittal of the compliance demonstration: Annual

SECTION 3B. CITATION TO AND DESCRIPTION OF APPLICABLE FEDERALLY ENFORCEABLE REQUIREMENTS

Emissions Unit No.: EU-3 **General Reference:** CPCN Case No. 9341, Cond. 8
Comar 26.11.09.07A(2)(b), NSPS 40 CFR Part 60 Subpart IIII

Briefly describe the Emission Standard/Limit or Operational Limitation: Sulfur content of ULSD shall not exceed 0.0015 weight percent (CPCN 9341 Condition 8), sulfur content of ULSD fuel oil shall not exceed 0.3 percent by weight (COMAR 26.11.09.07A(2)(b), sulfur content of diesel fuel shall not exceed 15 ppm (40 CFR 60.4207(b)).

The monitoring requirements for complhying with CPCN shall be the basis for complying with both COMAR and 40 CFR 60 Subpart IIII.

Part 70 Operating Permit No. 24-033-02200, Section IV, 2.1, Band E2

Permit Shield Request: Yes

Compliance Demonstration:

Check appropriate reports required to be submitted:

- ☑ Quarterly Monitoring Report:_____
- ☑ Annual Compliance Certification:_____
- ☑ Semi-Annual Monitoring Report: _____

Methods used to demonstrate compliance: Fuel sulfur content analysis

Monitoring: Reference CPCN 9341 Cond. 14 Describe: Perform sampling and analysis of "as fired" fuel oil in accordance with 40 CFR Part 75 Appendix D procedures. Obtain fuel supplier's certification the the fuel oil complies with the limitation of 0.3% by weight of the sulfur content in the fuel oil. Comply with the requirement under 40 CFR 60 Subpart IIII.

Testing: Reference Not applicable Describe: None

Record Keeping: Reference CPCN 9341 Cond. 14 Describe: Maintain records of fuel sampling and analysis for the "as fired" sulfur content of the ULSD fuel oil for at least five years. [CPCN 9341 Condition 14] Maintain records of fuel suppliers' certification of the percent sulfur content in the fuel on site for at least five years. [COMAR 26.11.09.07C]

Reporting: Reference CPCN 9341 Cond. 14 Describe: Submit, within 45 days of the end of each quarter, the result of the sulfur content of the fuel to MDE.

Frequency of submittal of the compliance demonstration: Quarterly

SECTION 3B. CITATION TO AND DESCRIPTION OF APPLICABLE FEDERALLY ENFORCEABLE REQUIREMENTS

Emissions Unit No.: EU-3 **General Reference:** COMAR 26.11.36.03A(1) and (5)

Briefly describe the Emission Standard/Limit or Operational Limitation: The emergency generator may not operate except for emergencies, testing, and maintenance perposes (black start events are periods of emergencies) except as allowed under 60.4211(f) and the engine may not be operated for testing and maintenance purposes between 12:01 a.m. to 2 p.m. on any day forcast with code oragne, red, or purple air quality.

Part 70 Operating Permit No. 24-033-02200, Section IV, 2.1, C1, CPCN No. 9341 Condition 17

Permit Shield Request: Yes

Compliance Demonstration:

Check appropriate reports required to be submitted:

- ☐ Quarterly Monitoring Report:_____
- ☑ Annual Compliance Certification:_____
- ☐ Semi-Annual Monitoring Report: _____

Methods used to demonstrate compliance: Recordkeeping

Monitoring: Reference Not Applicable Describe: None

Testing: Reference Not Applicable Describe: None

Record Keeping: Reference _____ Describe: Maintain a record of the date and time of the operation of the generator.

Reporting: Reference Not applicable Describe: None

Frequency of submittal of the compliance demonstration: Annual

SECTION 3B. CITATION TO AND DESCRIPTION OF APPLICABLE FEDERALLY ENFORCEABLE REQUIREMENTS

Emissions Unit No.: EU-3 **General Reference:** COMAR 26.11.09.08G and B

Briefly describe the Emission Standard/Limit or Operational Limitation: Installations with fuel-burning equipment with a capacity factor of 15 percent or less and operates less than 500 or less hours per year shall require the generator operator to attend operator traning programs at least once every 3 years. The equipment operate may be the person who maintains the equipment and makes the necessary adjustments for efficient operation.

Part 70 Operating Permit No. 24-033-02200, Section IV, 2.1, C2.

Permit Shield Request: Yes

Compliance Demonstration:

Check appropriate reports required to be submitted:

- ☐ Quarterly Monitoring Report:_____
- ☑ Annual Compliance Certification:_____
- ☐ Semi-Annual Monitoring Report: _____

Methods used to demonstrate compliance: Record keeping

Monitoring: Reference Not applicable Describe: None

Testing: Reference Not applicable Describe: None

Record Keeping: Reference COMAR 26.11.09.08G(e) Describe: Maintain a record of training program attendance for each operator at the site and make these records available to MDE.

Reporting: Reference Not Applicable Describe: None

Frequency of submittal of the compliance demonstration: Annual

SECTION 3B. CITATION TO AND DESCRIPTION OF APPLICABLE FEDERALLY ENFORCEABLE REQUIREMENTS

Emissions Unit No.: EU-3 **General Reference:** 40 CFR Patrt 60, Subpart III
40 CFR Part 63, Subpart ZZZZ

Briefly describe the Emission Standard/Limit or Operational Limitation: The emergency engine will meet the following emissions limits - 10.5 g/kW-hr NOx plus non-methane hydrocarbon, 3.5 g/kW-hr CO, and 0.54 g/kW-hr PM ((60.4202(b)(2) and 89.112 Tables 1 & 2). In addition, opacity shall not exceed 20 percent during acceleration mode, 15 percent during ugging mode, and 50 percent during peaks in either mode. Meeting t the above satisfies the requirements of 40 CFR Part 63, Subpart ZZZZ The emergency engine must be operated and maintained such that the emissions standards are met during hte life of the engine.

Part 70 Operating Permit No. 24-033-02200, Section IV, 2.1, C3, D, & E1; CPCN No. 9341 Condition 19.

Permit Shield Request: Yes

Compliance Demonstration:

Check appropriate reports required to be submitted:

- ☐ Quarterly Monitoring Report:_____
- ☑ Annual Compliance Certification:_____
- ☐ Semi-Annual Monitoring Report: _____

Methods used to demonstrate compliance:

Monitoring: Reference 60.4211(a) Describe: Operate and maintain the emergency engine according to the manufacturer's emission-related written instructions. Change only those emission-related settings that are permitted by the manufacturer.

Testing: Reference 60.4211(a) & 63.6590(c)(1) Describe: The permittee must comply by purchasing an engine certified to the required emissions standard.

Record Keeping: Reference COMAR 26.11.03.06C 40 CFR 60.4211 Describe: Maintain records of the established operating parameters to be monitored continuously to ensure the emergency engine continues to meet the emission standards.

Reporting: Reference COMAR 26.11.09.08G(1)(c) and (e) Describe: Submit records when requested by MDE.

Frequency of submittal of the compliance demonstration: Annual

SECTION 3B. CITATION TO AND DESCRIPTION OF APPLICABLE FEDERALLY ENFORCEABLE REQUIREMENTS

Emissions Unit No.: EU-3 **General Reference:** 40 CFR Part 60, Subpart IIII

Briefly describe the Emission Standard/Limit or Operational Limitation: The emergency engine may only operate during emergencies and for testing and maintenance purposes. It may not operate between 12:01 am and 2:00 pm on days with a code red, orange, or purple air quality alert unless it failed a previous test. The emergency engine is limited to operating 100 hours for the performance of maintenance, testing, and operations. There is no time limit for operation during emergencies.

Part 70 Operating Permit No. 24-033-02200, Section IV, 2.1, E3;, CPCN No. 9341 Conditions 17 and 20(b)..

Permit Shield Request: Yes

Compliance Demonstration:

Check appropriate reports required to be submitted:

- ☐ Quarterly Monitoring Report:_____
- ☑ Annual Compliance Certification:_____
- ☑ Semi-Annual Monitoring Report: _____

Methods used to demonstrate compliance: Recordkeepiong

Monitoring: Reference 40 CFR 60.4211 Describe: If the emergency engine does not meet the standards applicable to non-emergency engines, a non-resettable hour meter must be installed prior to startup of the engine.

Testing: Reference NA Describe: None

Record Keeping: Reference COMAR 26.11.03.06C & 40 CFR 60.4211(f) Describe: Maintain on-site, a record of operation of the engine to include fuel consumption, hours of operation, and purpose of operation.

Reporting: Reference COMAR 26.11.03.06C & 40 CFR 60.4211(f) Describe: Submit semi-annually a report of all relevant operating records to include hours of operation and purpose of operation.

Frequency of submittal of the compliance demonstration: Annual

SECTION 3C. OBSOLETE, EXTRANEOUS, OR INSIGNIFICANT PERMIT CONDITIONS

List permit to construct conditions which should be considered to be obsolete, extraneous, or environmentally insignificant.

Emissions Unit No.: EU-1 and EU-2 **Permit to Construct No.** Part 70 Permit 24-033-02200

Emissions Point No.	Date Permit Issued	Condition No.	Brief Description of Condition and Reason for Exclusion

SECTION 3D. ALTERNATE OPERATING SCENARIOS

Emissions Unit No.: EU-1 and EU-2

Briefly describe any alternate operating scenarios. Assign a number to each scenario for identification purposes.

The primary operating scenario for EU-1 and EU-2 is to combust either natural gas or liquefied natural gas (LNG).

EU-1 and EU-2 may also combust ULSD fuel oil. Annual operating CT hours for EU-1 and EU-2 combined during ULSD fuel oil firing are limited to a total of 2,400 pursuant to CPCN 9341 Condition No. 9. Each of these operating scenarios is described below.

Primary Operating Scenario: Combustion of Natural Gas or LNG

Fuel Type: Natural Gas or LNG

Maximum Turbine Operating Hours Per Year: 17,568 (based on a 366 day leap year)

Alternative Operating Scenario No. 1 (SCN-1): Combustion of ULSD Fuel Oil

Fuel Type: ULSD Fuel Oil

Maximum Turbine Operating Hours Per Year: 2,400

SECTION 3E. CITATION TO AND DESCRIPTION OF APPLICABLE FEDERALLY ENFORCEABLE REQUIREMENTS FOR AN ALTERNATE OPERATING SCENARIO

Scenario No.: SCN-1

Emissions Unit No.: EU-1 and EU-2 **General Reference:** COMAR 26.11.09.07A(2c), COMAR 26.11.09.08G(2), CPCN No. 9341 and NSPS 40 CFR Part 60 Subpart GG.

Briefly describe any applicable Emissions Standard/Limits/Operational Limitations:

COMAR 26.11.09.07A(2c), COMAR 26.11.09.08G(2), CPCN No. 9341 and NSPS 40 CFR Part 60, Subpart GG contain specific NOx and SO2 (fuel sulfur content) emission limits applicable to distillate fuel oil firing. The NOx and SO2 emission limits applicable to distillate fuel oil combustion were previously described in Section 3B.

Compliance Demonstration

Methods used to demonstrate compliance:

Monitoring: Reference COMAR 26.11.09.07A(2c), COMAR 26.11.09.08G(2), CPCN No. 9341 and NSPS 40 CFR Part 60.
Please refer to Section 3B.

Testing: Reference COMAR 26.11.09.07A(2c), COMAR 26.11.09.08G(2), CPCN No. 9341 and NSPS 40 CFR Part 60.
Please refer to Section 3B.

Record Keeping: Reference COMAR 26.11.09.07A(2c), COMAR 26.11.09.08G(2), CPCN No. 9341 and NSPS 40 CFR Part 60.
Please refer to Section 3B.

Reporting: Reference COMAR 26.11.09.07A(2c), COMAR 26.11.09.08G(2), CPCN No. 9341 and NSPS 40 CFR Part 60.
Please refer to Section 3B

S3D-1

Frequency of submittal of the compliance demonstration: Please refer to Section 3B

SECTION 4. CONTROL EQUIPMENT

1. Associated Emissions Units No. :	2. Emissions Point No.:
EU-1 and EU-2	EP-1 and EP-2

3. Type and Description of Control Equipment:

During natural gas or LNG combustion, dry low NOx (DLN) combustors are utilized to reduce the formation of NOx. DLN combustors premix turbine fuel and air prior to combustion in the primary zone. Use of a premix burner results in a homogeneous air/fuel mixture without an identifiable flame front. For this reason, the peak and average flame temperatures are the same, causing a decrease in thermal NOx emissions in comparison to a conventional diffusion burner. Currently, premix burners are limited in application to gaseous fuels and loads above approximately 35 to 50 percent of of baseline due to flame stability considerations.

4. Pollutants Controlled:	Control Efficiency:
NOx (during natural gas of LNG combustion)	Dry low NOx combustors during natural gas or LNG combustion will reduce the formation of NOx emissions (i.e. pollution prevention) by approximately 75 percent compared to water or steam injection and standard combustor design.

5. Capture Efficiency: Not applicable

SECTION 4. CONTROL EQUIPMENT

1. Associated Emissions Units No. :	2. Emissions Point No.:
EU-1 and EU-2	EP-1 and EP-2

3. Type and Description of Control Equipment:

During ULSD fuel oil combustion, water injection is utilized to reduce the formation of NOx. Injection of water into the primary combustion zone of a CT's combustors reduces the formation of thermal NOx by decreasing the peak combustion temperature. Water injection decreases the peak flame temperature by diluting the combustion gas stream and acting as a heat sink by absorbing heat necessary to: (a) vaporize the water (latent heat of vaporization), and (b) raise the vaporized water temperature to the combustion temperature. High purity water must be employed to prevent turbine corrosion and deposition of solids on the turbine blades. Water injection will not reduce the formation of fuel NOx.

4. Pollutants Controlled:	Control Efficiency:
NOx (during ULSD fuel oil combustion)	Water injection during ULSD fuel oil combustion will reduce the formation of NOx emissions (i.e. pollution prevention) by approximately 75 percent compared to standard combustor design.

5. Capture Efficiency: Not applicable

SECTION 5. SUMMARY SHEET OF POTENTIAL EMISSIONS

List all applicable pollutants in tons per year (tpy) pertaining to this facility. The Emissions Unit No. should be consistent with numbers used in Section 3. Attach a copy of all calculations. Not Applicable - see note below

Pollutant					
CAS Number					
Emissions Unit #					
Emissions Unit #					
Emissions Unit #					
Emissions Unit #					
Emissions Unit #					
Emissions Unit #					
Emissions Unit #					
Emissions Unit #					
Emissions Unit #					
Emissions Unit #					
Emissions Unit #					
Emissions Unit #					
Emissions Unit #					
Emissions Unit #					
Emissions Unit #					
Emissions Unit #					
Fugitive Emissions					
Total					

NOTE: In accordance with the MDE Part 70 Permit Application for Renewal Instructions on Page 8, Section 5 need only be completed in order to: (a) claim a regulatory exemption based on an emission cutoff, or (b) resolve a dispute over whether a particular requirement is applicable or whether a source is a major for a particular pollutant.

SECTION 6. EXPLANATION OF PROPOSED EXEMPTIONS FROM OTHERWISE APPLICABLE FEDERALLY ENFORCEABLE REQUIREMENTS

Describe and cite the applicable requirements to be exempted. Complete this Section only if the facility is claiming exemptions from or the non-applicability of any federally enforceable requirements.

1. Applicable Requirement:

40 CFR Part 63, Subpart YYYY

2. Brief Description:

National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines

3. Reasons for Proposed Exemption or Justification of Non-applicability:

Not applicable due to the Brandywine combustion turbines not being major sources of HAPs emissions since they emit less than 10 tons per year of a single HAP and less than 25 tons per year of total HAPs per 40 CFR §63.6085(b).

SECTION 7. COMPLIANCE SCHEDULE FOR NONCOMPLYING EMISSIONS UNITS

Not Applicable

1. Emissions Unit #	Anticipated Compliance Date
N/A	N/A
Applicable Federally Enforceable Requirement being Violated:	N/A

2. Description of Plan to Achieve Compliance:

N/A

Certified Progress Reports for sources in noncompliance shall be submitted at least quarterly to the Department.

SECTION 6. EXPLANATION OF PROPOSED EXEMPTIONS FROM OTHERWISE APPLICABLE FEDERALLY ENFORCEABLE REQUIREMENTS

Describe and cite the applicable requirements to be exempted. Complete this Section only if the facility is claiming exemptions from or the non-applicability of any federally enforceable requirements.

1. Applicable Requirement:

40 CFR Part 64, Compliance Assurance Monitoring (CAM)

2. Brief Description:

The Compliance Assurance Monitoring (CAM) regulatory program is designed to provide assurance of compliance with Part 70 emission limits. The CAM program is applicable to emission sources that are equipped with air pollution control devices. In brief, the CAM program requires proper operation and maintenance of air pollution devices. Operating within prescribed air pollution control indicator ranges provides assurance that the emission unit is operating in compliance with applicable emission limits.

3. Reasons for Proposed Exemption or Justification of Non-applicability:

The CAM rule s not applicable to the Brandywine facility CTs when firing NG or LNG since the CTs do not utilize a control device, as defined by 40 CFR 64.1 when firing these fuels. The 40 CFR §64.1 definition of a control device specifically excludes passive control measures that act to prevent pollutants from forming such as the use of combustion or other process design features or characteristics. The DLN combustor technology in use at the facility CTs when firing NG or LNG is a passive control measure that acts to prevent NOx from forming.

Although water injection in CTs is also considered to be a passive control measure that acts to prevent pollutants from forming (i.e. water injection neither destroys or removes NOx but rather prevents its formation) the facility CTs when firing fuel oil are potentially subject to the CAM rule for NOx since water injection is used to reduce NOx emissions and the 40 CFR §64.1 definition of a control device specifically lists "injection systems (such as water, steam, ammonia, sorbent or limestone injection)" as examples of common control devices. However, the CTs are exempt from CAM rule requirements during distillate fuel oil combustion pursuant to 40 CFR §64.2(1)(vi) since the current Part 70 permit specifies a continuous compliance determination method (as defined by 40 CFR §64.1) for the Part 70 permit NOx emission limit; i.e. NOx/O2 CEMS. The facility CTs are each equipped with NOx/O2 CEMS.

The Brandywine facility CTs are not equipped with a control device for any other emission-limited pollutants.

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STATE-ONLY ENFORCEABLE REQUIREMENTS

Facility Information:

Name of Facility: Brandywine Power	County Prince Georges
Premises Number: 16-2200	
Street Address: 16400 Mattawoman Drive	
24-hour Emergency Telephone Number for Air Pollution Matters: 301-782-4000	
Type of Equipment (List Significant Units):	
The Brandywine Power facility is a combined cycle system comprised of two (2) General Electric Frame 7EA combustion turbines (C	
two (2) unfired heat recovery steam generators (HRSGs), one (1) steam turbine (ST) and ancillary support equipment.	

CITATION TO AND DESCRIPTION OF APPLICABLE STATE-ONLY ENFORCEABLE REQUIREMENTS

Registration No.: 16-5-0844 and 16-5-0845

Emissions Unit No.: EU-1 and EU-2 **General Reference:** COMAR 26.11.06.08 and .09

Briefly describe the requirement and the emissions limit (if applicable):

Prohibits the discharge of emissions beyond the facility's property lines in such a manner that a nuisance or air pollution problem is created.

Methods used to demonstrate compliance:

Not Applicable

RENEWAL TITLE V APPLICATION
INSIGNIFICANT ACTIVITIES LIST

MARYLAND DEPARTMENT OF THE ENVIRONMENT
AIR AND RADIATION ADMINISTRATION
RENEWAL TITLE V APPLICATION INSIGNIFICANT ACTIVITIES LIST

III. Check-off List of Emissions Units and Activities Exempt from the Part 70 Permit Application

Insignificant Activities

Place a check mark beside each type of emissions unit or activity that is located at the facility. Where noted, please indicate the number of that type of emissions unit or activity located at the facility.

(1) No. ___ Fuel burning equipment using gaseous fuels or no. 1 or no. 2 fuel oil, and having a heat input less than 1,000,000 Btu (1.06 gigajoules) per hour;

(2) No. ___ Fuel-burning equipment using solid fuel and having a heat input of less than 350,000 Btu (0.37 gigajoule) per hour;

(3) No. 1 Stationary internal combustion engines with less than 500 brake horsepower (373 kilowatts)of power output Diesel-fired fire water pump engine

(4) X Space heaters utilizing direct heat transfer and used solely for comfort heat;

(5) ___ Water cooling towers and water cooling ponds unless used for evaporative cooling of water from barometric jets or barometric condensers, or used in conjunction with an installation requiring a permit to operate;

(6) No. 75 Unheated VOC dispensing containers or unheated VOC rinsing containers of 60 gallons (227 liters) capacity or less;

(7) ___ Commercial bakery ovens with a rated heat input capacity of less than 2,000,000 Btu per hour;

(8) ___ Kilns used for firing ceramic ware, heated exclusively by natural gas, liquefied petroleum gas, electricity, or any combination of these;

(9) ___ Confection cookers where the products are edible and intended for human consumption;

(10) ___ Die casting machines;

(11) ___ Photographic process equipment used to reproduce an image upon sensitized material through the use of radiant energy;

(12) ___ Equipment for drilling, carving, cutting, routing, turning, sawing, planing, spindle sanding, or disc sanding of wood or wood products;

(13)___ Brazing, soldering, or welding equipment, and cutting torches related to manufacturing and construction activities that emit HAP metals and not directly related to plant maintenance, upkeep and repair or maintenance shop activities;

(14)___ Equipment for washing or drying products fabricated from metal or glass, provided that no VOC is used in the process and that no oil or solid fuel is burned;

(15)___ Containers, reservoirs, or tanks used exclusively for electrolytic plating work, or electrolytic polishing, or electrolytic stripping of brass, bronze, cadmium, copper, iron, lead, nickel, tin, zinc, and precious metals;

(16) Containers, reservoirs, or tanks used exclusively for:

(a) ___ Dipping operations for applying coatings of natural or synthetic resins that contain no VOC;

(b) ___ Dipping operations for coating objects with oils, waxes, or greases, and where no VOC is used;

(c) X Storage of butane, propane, or liquefied petroleum, or natural gas;

(d) No. 20 Storage of lubricating oils:

(e) No. ___ Unheated storage of VOC with an initial boiling point of 300 °F (

(f) No. 3 Storage of Numbers 1, 2, 4, 5, and 6 fuel oil and aviation jet engine fuel,

(g) No. ___ Storage of motor vehicle gasoline and having individual tank capacities of 2,000 gallons (7.6 cubic meters) or less;

(h) No. 30 The storage of VOC normally used as solvents, diluents, thinners, inks, colorants, paints, lacquers, enamels, varnishes, liquid resins, or other surface coatings and having individual capacities of 2,000 gallons (7.6 cubic meters) or less;

(17) ___ Gaseous fuel-fired or electrically heated furnaces for heat treating glass or metals, the use of which does not involve molten materials;

(18) Crucible furnaces, pot furnaces, or induction furnaces, with individual capacities of 1,000 pounds (454 kilograms) or less each, in which no sweating or distilling is conducted, or any fluxing is conducted using chloride, fluoride,

or ammonium compounds, and from which only the following metals are poured or in which only the following metals are held in a molten state:

(a) ___ Aluminum or any alloy containing over 50 percent aluminum, if no gaseous chloride compounds, chlorine, aluminum chloride, or aluminum fluoride is used;

(b) ___ Magnesium or any alloy containing over 50 percent magnesium;

(c) ___ Lead or any alloy containing over 50 percent lead;

(d) ___ Tin or any alloy containing over 50 percent tin;

(e) ___ Zinc or any alloy containing over 50 percent zinc;

(f) ___ Copper;

(g) ____ Precious metals;

(19) ____ Charbroilers and pit barbecues as defined in COMAR 26.11.18.01 with a total cooking area of 5 square feet (0.46 square meter) or less;

(20) ___ First aid and emergency medical care provided at the facility, including related activities such as sterilization and medicine preparation used in support of a manufacturing or production process;

(21) X Certain recreational equipment and activities, such as fireplaces, barbecue pits and cookers, fireworks displays, and kerosene fuel use;

(22) ___ Potable water treatment equipment, not including air stripping equipment;

(23) ___ Firing and testing of military weapons and explosives;

(24) ___ Emissions resulting from the use of explosives for blasting at quarrying operations and from the required disposal of boxes used to ship the explosive;

(25) ____ Comfort air conditioning subject to requirements of Title VI of the Clean Air Act;

(26) ____ Grain, metal, or mineral extrusion presses;

(27) ____ Breweries with an annual beer production less than 60,000 barrels;

(28)___ Natural draft hoods or natural draft ventilators that exhaust air pollutants into the ambient air from manufacturing/industrial or commercial processes;

(29)____ Laboratory fume hoods and vents;

(30) No. ___ Sheet-fed letter or lithographic printing press(es) with a cylinder width of less than 18 inches;

For the following, attach additional pages as necessary:

(31) any other emissions unit, not listed in this section, with a potential to emit less than the "de minimus" levels listed in COMAR 26.11.02.10X (list and describe units):

No. ___ _____

No. ___ _____

No. ___ _____

No. ___ _____

No. ___ _____

(32) any other emissions unit at the facility which is not subject to an applicable requirement of the Clean Air Act (list and describe):

No. ___ _____

No. ___ _____

No. ___ _____

RENEWAL TITLE V APPLICATION CHECKLIST

MARYLAND DEPARTMENT OF THE ENVIRONMENT
AIR AND RADIATION ADMINISTRATION
RENEWAL TITLE V APPLICATION CHECKLIST

VI .Application Completeness Checklist

The purpose of this part is to list the information required to achieve a Part 70 application shield.

Cover Page

(✓) Name and address of owner or operator, including telephone number.

(✓) Name and address of facility, including the plant manager's name and telephone number.

(✓) A 24-hour emergency telephone number for air pollution matters.

Section 1 CERTIFICATION STATEMENTS

(✓) The certification statement completed and signed by a responsible official.

Section 2 FACILITY DESCRIPTION SUMMARY

(✓) A brief description of each of the source's process(es), including all applicable SIC codes and end products.

( ) Flow diagrams indicating all emissions units, emission points, and control devices.

( ) A plot plan of the entire facility.

There has been no change to the flow diagram or plot plan so submittal not required.

(✓) Emission Certification Report.

(✓) General Emissions Information.

Section 3 EMISSIONS UNIT DESCRIPTIONS –

This section must be completed for each emissions unit.

Part A

(✓) Emissions unit number.

(✓) Detailed description of unit, including all emission points.

(✓) Federally enforceable limit(s) on the operating schedule.

(✓) Fuel consumption information for <u>any</u> emissions unit that consumes fuel including the type of fuel, percent sulfur, and annual usage of fuel.

Part B

(✓) A citation and description of each federally enforceable requirement, including all emission standards, for each emissions unit.

(✓) A statement of compliance demonstration techniques for each requirement, including a description of monitoring, record keeping, reporting requirements, and test methods.

(✓) The frequency of submittal of the compliance demonstration during the permit term.

Part C

(✓) Emissions unit number.

(✓) Permit to construct number.

(✓) Emissions point number(s).

(✓) Date(s) the permit to construct was issued.

(✓) Condition number(s) as indicated on the permit to construct.

(✓) Description of the permit condition(s) and the reason(s) why they are believed to be obsolete, extraneous, or insignificant.

Part D

(✓) Description of all alternate operating scenarios that apply to an emissions unit.

(✓) Number assigned to each scenario.

(✓) Emissions unit number.

(✓) Description of the operating parameters for the emissions unit and other information which describes the how the operation of the unit will change under the different scenario.

Part E

(✓) A citation and description of each federally enforceable requirement triggered by an operating scenario, including all emission standards, for each emissions unit.

(✓) As an attachment, the date and results of the most recent compliance demonstration for each emission standard and/or emissions certification report with relevant supporting documentation.

(✓) A statement of compliance demonstration techniques for each requirement, including a description of monitoring, record keeping, reporting requirements, and test methods.

(✓) The frequency of submittal of the compliance demonstration during the permit term.

Section 4 CONTROL EQUIPMENT

(✓) The type of each piece of air pollution control equipment

(✓) The capture and control efficiencies of the control equipment.

Section 5 SUMMARY SHEET OF POTENTIAL EMISSIONS

(✓) Quantity of potential emissions for criteria pollutants and HAPs emitted in tons per year for each emissions unit.

(✓) Fugitive emission estimations for the entire facility for criteria pollutants and HAPs emitted in tons per year.

(✓) Basis for all emission calculations.

Section 6 AN EXPLANATION OF PROPOSED EXEMPTIONS FROM OTHERWISE APPLICABLE FEDERALLY ENFORCEABLE REQUIREMENTS

(✓) An explanation of the proposed exemption.

Section 7 COMPLIANCE SCHEDULE FOR NONCOMPLYING EMISSIONS UNITS

(✓) Identification of emissions unit(s) not in compliance, including the requirement being violated and the effective compliance date.

(✓) Detailed description of methods to be used to achieve compliance.

(✓) A schedule of remedial measures, including an enforceable sequence of actions with milestones.

Attachment

(✓) Checklist of Insignificant Activities

( ) CAM Plan (If Applicable)

ATTACHMENT A
EMAIL CORRESPONDENCE
(EMAIL FROM MR. BILL PAUL TO MR. MARK BRIGGS DATED JUNE 26, 2017)

Kerry Higgins

From: Bill Paul -MDE- <bill.paul@maryland.gov>
Sent: Monday, June 26, 2017 3:18 PM
To: Mark Briggs
Cc: Karen Irons -MDE-; Roland Gorschboth -MDE-; George Ikhinmwin -MDE-
Subject: Fwd: KMC Thermo, LCC - Air Permit Administrative Change Application

Mark Briggs, GM

Karen Irons asked me to respond to your June 21, 2017 email requesting an amendment to the current Title V Operating Permit for KMC Thermo. Specifically, you requested that the recently approved PSC amendments to the CPCN be incorporated into the Title V Operating Permit. The underlying motive for your request is to remove the language discrepancy that now exists between the newly amended CPCN conditions and the existing Title V operating permit conditions as it relates to operation of the combustion turbines; and thereby eliminate the possibility that the language discrepancy could result in a violation of the Title V permit.

As the ARMA Permits Program and Compliance Program worked closely with KMC Thermo to effectuate the requested CPCN amendments, we are fully cognizant of the discrepancy. However, it has been common ARMA practice to incorporate minor or insignificant activities during the renewal process of the Title V permit. The amended CPCN conditions are deemed to me minor and does not warrant an immediate action by ARMA. Therefore, to address your specific concern regarding enforcement of the Title V conditions that are superseded by the amended conditions, please accept the following as ARMAs enforcement policy with respect to those conditions:

Until the Title V Operating is renewed, KMC Thermo is obligated to comply with all the requirements in the current Title V permit with the exception of those conditions that have been superseded by the PSC Order issued on April 5, 2017 which amended certain requirements.

The ARMA Compliance inspector for the facility, Roland Gorschboth, is copied on this correspondence to further ensure that there is no misunderstanding. Should you have any additional questions or concerns, please feel free to contact me at 410.537.3276 or Mr. Gorschboth at 410.537.4130.

Regards

Bill Paul, Chief
Combustion and Metallurgical Division
Air & Radiation Management Admin

(410) 537-3276

---------- Forwarded message ----------
From: **Mark Briggs** <Mark.Briggs@brandywinepower.com>
Date: Wed, Jun 21, 2017 at 2:56 PM
Subject: KMC Thermo, LCC - Air Permit Administrative Change Application
To: "karen.Irons@maryland.gov" <karen.Irons@maryland.gov>
Cc: Mike Fulcher <mfulcher@tateswood.com>, Jack Borsch <John.Borsch@ihipower.com>, Angela Mendolia <Angela.Mendolia@ihipower.com>, "Samuel M. Warfield (swarfield@arroyoenergygroup.com)" <swarfield@arroyoenergygroup.com>

Karen-

I am sending you this note in accordance with your request during today's telephone conversation. It might be helpful to begin by providing some background information.

On February 28, 2017, KMC Thermo, LLC requested that the Maryland Public Service Commission approve certain amendments to the Brandywine CPCN. Specifically, we asked the Commission to replace the 51-MW minimum operating load in Condition No. 7 with functional parameters corresponding more precisely with the engagement of the Facility's NOx pollution control system—the achievement of premix mode for operations on natural gas and water injection for operations on ULSD. We also sought MDE's acknowledgement that, for compliance purposes, an adjustment would be necessary so as to exclude the first 17 minutes of CEMS data after engagement of these control systems. On MDE's and PPRP's joint recommendation, the Public Service Commission approved the proposed CPCN amendments on April 5, 2017, and acknowledged the need to adjust CEMS reporting as KMC Thermo had requested.

KMC Thermo submitted an application for amendments to our Title V Operating Permit on May 26, 2017 to incorporate the foregoing CPCN amendments. While the CPCN amendments did not constitute CPCN modifications, they embody significant changes in Facility operations and compliance monitoring. For this reason, we believe it would be appropriate to immediately incorporate the CPCN amendments in the Title V Operating Permit, rather than waiting until the reissuance of the Operating Permit as of January 1, 2020. The latter approach improperly puts KMC Thermo at risk of technically violating its Operating Permit even if its operations completely conform to the amended CPCN.

If it is impossible to amend the Title V Operating Permit as requested, we believe it would be appropriate for MDE to issue a binding written statement assuring KMC Thermo that no enforcement action of any sort will be taken with respect to the period from April 5, 2017 until such time as all amended CPCN provisions are incorporated in the Operating Permit, so long as KMC Thermo operates the Facility in accordance with the April 5, 2017 CPCN amendments, including the approved adjustment to CEMS monitoring data discussed above.

Kind regards,

Mark Briggs | General Manager
Brandywine Power Facility | IHI Power Services Corp.
16400 Mattawoman Drive, Brandywine, MD 20613
Office 301-782-4000 | Fax 301-782-4004
Cell 301-399-6761
Email Mark.Briggs@BrandywinePower.com

Click here to complete a three question customer experience survey.

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ATTACHMENT B
SUGGESTED REDLINE CHANGES

Operational Limitations

G1. CPCN Case No. 9341, Air Quality Section, Condition No. 9

The combustion turbines shall generate electricity using natural gas or LNG only except as otherwise provided for in these conditions:

(a) When the fuel delivery to the turbines is interrupted or curtailed, the facility may burn ULSD fuel oil but shall be limited to 143 tons of NO_X when burning ULSD fuel oil;

(b) If the facility has reached its 143 tons limit and there is a PJM system emergency as defined in Condition No. 11 and natural gas is unavailable, the facility may burn ULSD fuel oil; and

(c) Under no circumstances, however, may the facility burn ULSD fuel oil for more than 2,400 turbine hours.

For the purposes of this condition, a year is defined as November 1 through October 31. Natural gas/LNG service interruptions shall be verified by a letter each year from Brandywine's natural gas/LNG supplier identifying the dates on which service was restricted. Brandywine will ensure that the Department receives a copy of this letter within 60 days of the start of each New Year.

G2. CPCN Case No. 9341, Air Quality Section, Condition No. 11

For the purposes of Conditions Nos. 6 and 9 of the CPCN, a PJM system emergency is operation during reserve shortages and refers to Maximum Generation Emergency, as defined in Section 2.0 of PJM Manual 35: Definitions and Acronyms, Revision 22 Effective date 2/28/2013.

G3. CPCN Case No. 9341, Air Quality Section, Condition No. 7

Except for periods of startup, shutdown periods and Black Start Events, each combustion turbine ~~generator shall operate at a load of not less than 51 megawatts.~~ **unit shall operate only when the unit, for natural gas or LNG firing, is in DLN premix mode, or when firing ULSD fuel oil, water injection is engaged.**

Note that after the initiation of premix steady state while firing natural gas or LNG and upon initiation of water injection while firing ULSD fuel, an emissions monitoring stabilization period of up to 17 minutes is required to accommodate exhaust gas transit time from the exit of the combustion system to the CEMS.

Compliance Demonstration

The Permittee shall maintain records of the hours that the turbines burn ULSD fuel oil and record periods, except for startups, shutdowns, and Black Start Events, when each combustion turbine generator operates ~~at less than 51 megawatts~~ **without water injection engaged.** **[Reference: COMAR 26.11.03.06C]**

The Permittee shall in addition, submit the quarterly reports within 45 days of the end of each calendar quarter, and shall include at least the following for each turbine (monthly summaries)

(a) The total hours of operation;
(b) The number of hours of operation burning ULSD fuel oil;
(c) The total amount of ULSD fuel oil burned, in units of gallons and MMBtu during the quarter;
(d) The number of hours of operation burning natural gas and LNG;

(e) The total amount of natural gas and LNG burned, in units of SCF and MMBtu during the quarter;
(f) Times of start-up and shutdown, and Black Start Events;
(g) The megawatts of electricity produced on an hourly basis; and
(h) Maximum hourly and average hourly NOx emissions, in units of ppmvd at 15 percent oxygen and pounds per hour, and the cumulative annual NOx emissions.
(i) Any emissions in excess of NOx concentrations specified in this permit, including the amount of the emissions, the date(s) on which the excess emissions occurred, the length of time over which the excess emissions occurred, the reason(s) why the excess emissions occurred, and the corrective action taken, if required, to ensure that excess emissions do not occur in the future.
(j) Any periods, except startup and shutdowns and Black Start Events, that the turbines operated ~~at less than 51 megawatts~~ **for natural gas or LNG firing, and not in DLN premix mode, or when firing ULSD fuel oil, and water injection is not engaged;** and

The quarterly report as required above shall be in the format approved by the Department. Valid CEMS data are required for a minimum of 90 percent of the plant operating hours in each quarter **[References**: **CPCN 9341, Conditions Nos. 13 and 14]**.

Compliance Status
The Permittee complies with the stated requirements and maintains records of the hours that the turbines burn (ULSD) fuel oil except for startups and shutdowns, when each combustion turbine generator operates ~~at less than 51 megawatts~~ **and water injection is not engaged**.

For the past five calendar years (2010 through 2014) the two combustion turbines combined for a total of 152.4 hours of operation on fuel oil. For the same time frame, the turbines operated a total 36, 309 hours on natural gas. The total hours of operation when burning No. 2 fuel oil are insignificant when compared to the maximum allowable 2400 hours per year for which No. 2 fuel oil may be burned. (Condition No. 9 of the CPCN #9341)

Emissions Unit EU-3
Emission Unit EU-3 is one (1) Caterpillar diesel engine Model C175-20 rated at 4000 kW, burning ULSD fuel oil used for Black Start Events.

A. Control of Visible Emissions

A1. **COMAR 26.11.09.05E (2)** Emissions During Idle Mode. A person may not cause or permit the discharge of emissions from any engine, operating at idle, greater than 10 percent opacity.

A2. **COMAR 26.11.09.05E (3)** Emissions During Operating Mode. A person may not cause or permit the discharge of emissions from any engine, operating at other than idle conditions, greater than 40 percent opacity.

	Table IV – 1
	Brandywine's natural gas/LNG supplier identifying the dates on which service was restricted. Brandywine will ensure that the Department receives a copy of this letter within 60 days of the start of each new year. [**Reference: CPCN No. 9341 condition 9, Air Quality Section**]. G2 **CPCN Case No. 9341, Air Quality Section, Condition No. 11.** For the purposes of Conditions Nos. 6 and 9 of the CPCN, a PJM system emergency is operation during reserve shortages and refers to Maximum Generation Emergency, as defined in Section 2.0 of PJM Manual 35: Definitions and Acronyms, Revision 22 Effective date 2/28/2013. G3. **CPCN Case No. 9341, Air Quality Section, Condition No. 7.** Except for start-up and shutdown periods, and except during Black Start Events, each combustion turbine ~~generator shall operate at a load of not less than 51 megawatts~~ **unit shall operate only when the unit, for natural gas or LNG firing, in DLN premix mode, or when firing ULSD fuel oil, water injection engaged. [Reference: CPCN No.9341, Air Quality Section].** **Note that after the initiation of premix steady state while firing natural gas or LNG and upon initiation of water injection while firing ULSD fuel, an emissions monitoring stabilization period of up to 17 minutes is required to accommodate exhaust gas transit time from the exit of the combustion system to the CEMS.**
1.2	**Testing Requirements:** A. Visible Emissions Limitation See monitoring B. Sulfur Oxide and Sulfuric Acid Mist Emissions The Permittee shall comply with the CPCN requirements by performing sampling and analysis of the "as fired" ULSD fuel oil to determine the percentage of sulfur by weight in the ULSD fuel oil as prescribed in 40 CFR 75 Appendix D [**Reference: CPCN No. 9341, Conditions No. 5 and No. 8, Air Quality Section**]. The Permittee shall perform QA/QC procedures for the SO_2 monitoring system in accordance with 40 CFR Part 75 Appendix D. [**Reference: CPCN No. 9341, Conditions No. 5 and No. 8, NSPS 40 CFR 60.334(h), and Acid Rain 40 CFR Part 75.21].** C. Nitrogen Oxide Emissions The Permittee shall perform QA/QC procedures for the NOx monitoring system in accordance with 40 CFR Part 75 Appendix D. [**Reference: CPCN No. 9341, Condition 8, NSPS 40 CFR 60.334(h), COMAR 26.11.09.08B(2)(c) and Acid Rain 40 CFR Part 75.70(e)].** D. Carbon Monoxide Emissions See monitoring E **Volatile Organic Compound** See monitoring

Table IV – 1	
	F. Particulate Matter Emissions The Permittee maintain records of the preventative maintenance which relate to combustion performance [**References: COMAR 26.11.03.06C**]. G. Operational Limitation The Permittee shall maintain record of the hours that the turbines burn ULSD fuel oil and record periods, except for startups, shutdowns, and Black Start Events when each combustion turbine generator operates ~~at less than 51 megawatts~~ **with water injection not engaged** [**Reference: COMAR 26.11.03.06C**].
1.5	**Reporting Requirements:** A. Visible Emissions Limitation The Permittee shall report incidents of visible emissions in accordance with Condition 4 of Section III "Report of Excess Emissions and Deviation. [**Reference: COMAR 26.11.03.06C**]. B. Sulfur Oxide and Sulfuric Acid Mist Emissions **CPCN** The Permittee shall submit quarterly, within 45 days of the end of each quarter, the result of the sulfur content of the fuel to the Department within 45 days of the availability of the result [**Reference: CPCN No. 9341, Air Quality Section, Condition No. 14**]. **Note:** For any calendar quarter during which no delivery of ULSD fuel oil is received, the quarterly report shall state that no ULSD fuel oil was received during the quarter. **NSPS** For each affected unit required to continuously monitor parameters or emissions or to periodically determine the sulfur content or fuel nitrogen content under this subpart, the owner or operator shall submit reports of excess emissions and monitor downtime, in accordance with section 60. 7(c). Excess emissions shall be reported for all periods of unit operation, including startup, shutdown and malfunction. For the purpose of reports required under section 60.7(c), periods of excess emissions and monitor downtime, which shall be reported are defined as follows: (i) For samples of gaseous fuel and for ULSD fuel oil samples obtained using daily sampling, flow proportional sampling or sampling from unit's storage tank, an excess emission occurs each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the gas turbines exceeds 0.8 weight percent and ending on a date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit.

Table IV – 1	
	(g) The megawatts of electricity produced by each turbine on an hourly basis; (h) Maximum hourly and average hourly NOx emissions, in units of ppmvd at 15 percent oxygen and pounds per hour, and the cumulative annual NOx emissions; (i) Any emissions in excess of NOx concentrations specified in this permit, including the amount of the emissions, the date(s) on which the excess emissions occurred, the length of time over which the excess emissions occurred, the reason(s) why the excess emissions occurred, and the corrective action taken, if required, to ensure that excess emissions do not occur in the future; and (j) Any periods, except startup, shutdowns, and Black Start Events that the turbine operated~~, at less than 51 megawatts~~ **for natural gas or LNG firing, when not in DLN premix mode, or for firing on ULSD fuel oil, with water injection not engaged**; and The quarterly report as required above shall be in the format approved by the Department. Valid CEMS data are required for a minimum of 90 percent of the plant operating hours in each quarter **[References**: **CPCN 9341, Conditions Nos. 13 and 14]**.

A Permit Shield shall cover the applicable requirements identified for the emissions units listed in the table above.

Table IV – 2	
2.0	**Emissions Unit:** Emission Unit EU-3: One (1) Caterpillar diesel engine Model C175-20 rated at 4000 kW burning Ultra low-sulfur diesel fuel oil.
2.1	**Applicable Standards/Limits:** A. Control of Visible Emissions A1. **COMAR 26.11.09.05E (2)** Emissions During Idle Mode. A person may not cause or permit the discharge of emissions from any engine, operating at idle, greater than 10 percent opacity. A2. **COMAR 26.11.09.05E (3)** Emissions During Operating Mode. A person may not cause or permit the discharge of emissions from any engine, operating at other than idle conditions, greater than 40 percent opacity.

ATTACHMENT C
2017 EMISSIONS CERTIFICATION REPORT

Brandywine POWER

A KMC Thermo, LLC Company

Monday, March 5, 2018

Ms. Laramie Daniel, Compliance Program
Maryland Department of the Environment - ARMA
1800 Washington Boulevard, Suite 715
Baltimore, MD 21230-1720

Re: Brandywine Power Facility - facility number 033-02200
Criteria Air Pollutants Emissions Certification for 2017

Dear Ms. Daniel,

Enclosed are two copies of the Criteria Air Pollutants (CAP) Emissions Certification for this facility as required under COMAR 26.11.02.19, C and D. The emissions certified include total particulates, sulfur oxides, nitrogen oxides, carbon monoxide, volatile organic compounds, and greenhouse gases for calendar year 2017.

We have also included the certification for HAPS and Toxic Air Pollutant emissions as indicated by the current EPA AP42 factors. There is no Billable Toxic Air Pollutant (Form5) emission in this submission as AP42 does not indicate any such emissions for Brandywine's combustion turbines or Emergency Diesel Generator.

I certify that I am familiar with each of the sources and that I am responsible for the accuracy of the facility Emissions Certification Report. After review of the enclosed Emissions Certification Report forms, I certify that they are true and accurate to the best of my knowledge.

Please contact myself or Mark Briggs if there are any questions in regard to any of the information enclosed.

Sincerely,

Mike Fulcher
Asset Manager

MF/mtb

Enclosures: 2 copies, Emissions Calculation Sheet(s)
cc: Associate Director, EPA Region III (via email)
file

16400 Mattawoman Drive Brandywine, Maryland 20613
301-782-4000 Fax 301-782-4004

MARYLAND DEPARTMENT OF THE ENVIRONMENT
1800 Washington Boulevard, Suite 715 • Baltimore Maryland 21230-1720
410-537-3000 • 1-800-633-6101 • http://www.mde.state.md.us
Air and Radiation Management Administration
Air Quality Compliance Program
410-537-3220

FORM 1:

GENERAL FACILITY INFORMATION
EMISSIONS CERTIFICATION REPORT

Calendar Year: 2017

A. FACILITY IDENTIFICATION	Do Not Write in This Space
Facility Name Brandywine Power Facility	Date Received Regional
Address 16400 Mattawoman Drive	Date Received State
City Brandywine County Prince Georges Zip Code 20613	AIRS Code
B. Briefly describe the major function of the facility	FINDS Code
Electric Power Generation	SIC Code
	Facility Number:
	TEMPO ID:
C. SEASONAL PRODUCTION (%, if applicable)	Reviewed by:
Winter *(Dec.-Feb.)* / Spring *(Mar – May)* / Summer *(Jun – Aug)* / Fall *(Sept – Nov)*	Name Date

D. Explain any increases or decreases in emissions from the previous calendar year for each registration at this facility.

Any such changes are the result of increased or decreased plant operation.

E. CONTROL DEVICE INFORMATION (for NOx and VOC sources only)

Control Device	Capture Efficiency	Removal Efficiency

I am familiar with the facility and the installations and sources for which this report is submitted. I have personally examined the information in this report, which consists of 30 pages (including attachments), and certify that the information is correct to the best of my knowledge.

Mike Fulcher — Name (Print/Type)
Asset Manager — Title
Date
Signature
301-782-4000 — Telephone

1/09/08

Brandywine Power Facility
Emissions Calculation Sheet

Calendar Year 2017

Sulfur Oxide Emissions

Emission rates per 40CFR75 App. D eqns. [lb/mmBtu]		Unit 1 [lbs] (1)	Unit 2 [lbs] (1)	Unit 3 [lbs] (1)
Gas	6.0E-04	1571.1	1843.1	-
Fuel Oil	6.7E-04	4.1	6.9	-
Emission rate per AP42 [lb/mmBtu]		-	-	-
		-	-	-
Fuel Oil	8.7E-04	-	-	0.4114
	Total	**1,575.2**	**1,850.0**	**0.4114**
(4)	**[Tons/Year]**	**0.8**	**0.9**	**0.00021**
(5)	**[Lbs/Day]**	**8.3**	**7.9**	**0.01**

Particulate Emissions - TOTAL

Emission rate per AP42 [lb/mmBtu]		Unit 1 [lbs] (1)	Unit 2 [lbs] (1)	Unit 3 [lbs] (1)
Gas	6.6E-03	17282.4	20274.2	-
Fuel Oil	1.2E-02	53.6	90.6	-
Fuel Oil	7.0E-02	-	-	33.0
	Total	**17,336**	**20,365**	**33.0**
(4)	**[Tons/Year]**	**8.7**	**10.2**	**0.017**
(5)	**[Lbs/Day]**	**91.2**	**86.7**	**0.9**

Nitrogen Oxide Emissions (NOx)

	Unit 1 [lbs/hr] (3)	Unit 2 [lbs/hr] (3)	Unit 3 [lbs/hr] (11)	Unit 1 [lbs] (2)	Unit 2 [lbs] (2)	Unit 3 [lbs] (12)
Gas	19.97	20.40	-	67,034	84,161	-
Fuel Oil	303.90	237.14	-	2,185	3,121	-
Fuel Oil	-	-	69.60	-	-	875
		Total		**69,219**	**87,282**	**875**
		[Tons/Year]		**34.6**	**43.6**	**0.44**
(5)		**[Lbs/Day]**		**364.3**	**371.4**	**23.0**
(9)		**TOSD [lbs/day]**		**167.3**	**353.2**	**23.6**

Nitrous Oxide Emissions (N2O)

Emission rate per AP42 [lb/mmBtu]		Unit 1 [lbs] (1)	Unit 2 [lbs] (1)	Unit 3 [lbs] (1)
Gas	3.0E-03	7,855.6	9,215.6	-
Fuel Oil	(no AP42 factor)	0.0	0.0	-
rate per 40CFR98 [lb/mmBtu]		-	-	-
		-	-	-
Fuel Oil	1.3E-03	-	-	0.6
	Total	**7,856**	**9,216**	**0.6**
(4)	**[Tons/Year]**	**3.9**	**4.6**	**0.00031**
(5)	**[Lbs/Day]**	**41.3**	**39.2**	**0.02**

Carbon Monoxide Emissions

Emission rate per AP42 [lb/mmBtu]		Unit 1 [lbs] (1)	Unit 2 [lbs] (1)	Unit 3 [lbs] (12)
Gas	1.5E-02	39,278.1	46,077.8	-
Fuel Oil	7.6E-02	353.9	598.9	-
Mnfr. Performance Data [lbs/hr] (11)		-	-	-
		-	-	-
Fuel Oil	4.43	-	-	55.7
	Total	**39,632.1**	**46,676.6**	**55.7**
(4)	**[Tons/Year]**	**19.8**	**23.3**	**0.0279**
(5)	**[Lbs/Day]**	**208.6**	**198.6**	**1.5**

VOC Emissions

Emission rate per AP42 [lb/mmBtu]		Unit 1 [lbs] (1)	Unit 2 [lbs] (1)	Unit 3 [lbs] (12)
Gas	2.1E-03	5,498.9	6,450.9	-
Fuel Oil	4.1E-04	1.9	3.2	-
Mnfr. Performance Data [lbs/hr] (11)				-
				-
Fuel Oil	0.69	-	-	7.4
	Total	**5,501**	**6,454**	**7.4**
(4)	**[Tons/Year]**	**2.8**	**3.2**	**0.0037**
(5)	**[Lbs/Day]**	**29.0**	**27.5**	**0.2**
(6)	**TOSD [lbs]**	**3,181.0**	**3,071.3**	**3.4**

Annual Heat Input (see note 10)

	Unit 1 [mmBtu]	Unit 2 [mmBtu]	total [mmBtu]	Unit 3 [mmBtu]
Gas	2,618,542	3,071,850	**5,690,393**	-
Fuel Oil	4,657	7,880	**12,537**	**474**
TOSD - Gas	1,514,198	1,462,017	**2,976,216**	-
TOSD - Fuel Oil	2,828	2,673	**5,501**	**217**

Methane Emissions (CH4)

Emission rate per AP42 [lb/mmBtu]		Unit 1 [lbs] (1)	Unit 2 [lbs] (1)	Unit 3 [lbs] (1)
Gas	8.6E-03	22,519.5	26,417.9	
Fuel Oil	(no AP42 factor)	0.0	0.0	-
rate per 40CFR98 [lb/mmBtu]		-	-	
		-	-	
Fuel Oil	6.6E-03	-	-	3.1
	Total	**22,519**	**26,418**	**3.1**
(4)	**[Tons/Year]**	**11.3**	**13.2**	**0.0016**
(5)	**[Lbs/Day]**	**118.5**	**112.4**	**0.1**

Operating Data (see note 7)

Unit 1	Total Operating Hours	Gas Hours	Oil Hours		Hrs/Day	Days/Wk	Wk/Yr	Days/ Yr
	3,364	**3,356.7**	**7.2**		**17.7**	**3.7**	**52**	**190**
Unit 2	Total Operating Hours	Gas Hours	Oil Hours		Hrs/Day	Days/Wk	Wk/Yr	Days/ Yr
	4,139	**4,125.6**	**13.2**		**17.6**	**4.5**	**52**	**235**
Unit 3	Total Operating Hours			Oil Gallons	HHV	Hrs/Day	Days/Wk	Wk/Yr	Days/ Yr
	27.9			**3,483**	**0.136**	**0.7**	**0.7**	**52**	**38**

TOSD Operating Data (see note 7)

Unit 1	Total Operating Hours	Gas Hours	Oil Hours		Hrs/Day	Days/Yr	Total NOx Lbs.
	1908	**1,903.6**	**4.2**		**17.2**	**111**	**18,568**
	Ozone Season NOx [lbs]	**18,124**	**444**				
Unit 2	Total Operating Hours	Gas Hours	Oil Hours		Hrs/Day	Days/Yr	Total NOx Lbs.
	1935	**1,930.4**	**4.2**		**17.1**	**113**	**39,915**
	Ozone Season NOx [lbs]	**38,717**	**1,198**				
Unit 3	Total Operating Hours		Oil Hours	Oil Gallons	Hrs/Day	Days/Yr	Total NOx Lbs.
	11		**11**	**1,595**	**0.7**	**17**	**401**
	Ozone Season NOx [lbs]		**401**				

Brandywine Power Facility
Emissions Calculation Sheet

HAPs **total (all):** **2.93** **[tons/yr]**

Acetaldehyde

	Emission rate per AP42 [lb/mmBtu]	Unit 1 [lbs] (1)	Unit 2 [lbs] (1)	Unit 3 [lbs] (1)		
Gas	4.0E-05	104.7	122.9	-		
Fuel Oil	0.0E+00	0.0	0.0	-		
Fuel Oil	2.5E-05	-	-	0.012		
	Total	**104.7**	**122.9**	**0.012**	**227.6**	
	(4) [Tons/Year]	**0.052**	**0.061**	**0.0000060**	**0.11**	YES
	(5) [Lbs/Day]	**0.5513**	**0.5229**	**0.0003**	**1.07**	
	[lbs/hr]	**0.03**	**0.03**	**0.000428**	**0.06**	NO

Acrolein

	Emission rate per AP42 [lb/mmBtu]	Unit 1 [lbs] (1)	Unit 2 [lbs] (1)	Unit 3 [lbs] (1)		
Gas	6.4E-06	16.8	19.7	-		
Fuel Oil	0.0E+00	0.0	0.0	-		
Fuel Oil	7.9E-06	-	-	0.0037		
	Total	**16.8**	**19.7**	**0.0037**	**36.4**	
	(4) [Tons/Year]	**0.008**	**0.010**	**0.0000019**	**0.02**	YES
	(5) [Lbs/Day]	**0.0882**	**0.0837**	**0.0001**	**0.1720**	
	[lbs/hr]	**0.0050**	**0.0048**	**0.0001**	**0.0099**	YES

Arsenic

	Emission rate per AP42 [lb/mmBtu]	Unit 1 [lbs] (1)	Unit 2 [lbs] (1)	Unit 3 [lbs] (1)		
Gas	0.0E+00	0.0	0.0	-		
Fuel Oil	1.1E-05	0.1	0.1	-		
Fuel Oil	0.0E+00	-	-	0.0000		
	Total	**0.1**	**0.1**	**0.0000**	**0.1**	
	(4) [Tons/Year]	**0.000**	**0.000**	**0.0000000**	**0.0001**	NO
	(5) [Lbs/Day]	**0.0003**	**0.0004**	**0.0000**	**0.0006**	
	[lbs/hr]	**0.0071**	**0.0066**	**0.0000**	**0.014**	YES

Benzene

	Emission rate per AP42 [lb/mmBtu]	Unit 1 [lbs] (1)	Unit 2 [lbs] (1)	Unit 3 [lbs] (1)		
Gas	1.2E-05	31.4	36.9	-		
Fuel Oil	5.5E-05	0.3	0.4	-		
Fuel Oil	7.8E-04	-	-	0.3676		
	Total	**31.7**	**37.3**	**0.3676**	**69.3**	
	(4) [Tons/Year]	**0.016**	**0.019**	**0.0001838**	**0.035**	NO
	(5) [Lbs/Day]	**0.1667**	**0.1587**	**0.0097**	**0.3351**	
	[lbs/hr]	**0.0094**	**0.0090**	**0.0132**	**0.0316**	YES

Beryllium

	Emission rate per AP42 [lb/mmBtu]	Unit 1 [lbs] (1)	Unit 2 [lbs] (1)	Unit 3 [lbs] (1)		
Gas	0.0E+00	0.0	0.0	-		
Fuel Oil	3.1E-07	0.001	0.002	-		
Fuel Oil	0.0E+00	-	-	0.0000		
	Total	**0.001**	**0.002**	**0.0000**	**0.004**	
	(4) [Tons/Year]	**0.000**	**0.000**	**0.0000000**	**0.000**	NO
	(5) [Lbs/Day]	**0.0000**	**0.0000**	**0.0000**	**0.0000**	
	[lbs/hr]	**0.0002**	**0.0002**	**0.0000**	**0.0004**	YES

1,3-Butadiene

	Emission rate per AP42 [lb/mmBtu]	Unit 1 [lbs] (1)	Unit 2 [lbs] (1)	Unit 3 [lbs] (1)		
Gas	4.3E-07	1.1	1.3	-		
Fuel Oil	1.6E-05	0.1	0.1	-		
Fuel Oil	0.0E+00	-	-	0.0000		
	Total	**1.2**	**1.4**	**0.0000**	**2.6**	
	(4) [Tons/Year]	**0.001**	**0.001**	**0.0000000**	**0.0013**	YES
	(5) [Lbs/Day]	**0.0063**	**0.0062**	**0.0000**	**0.0125**	
	[lbs/hr]	**0.00**	**0.00**	**0.0000**	**0.0007**	NO

Cadmium

	Emission rate per AP42 [lb/mmBtu]	Unit 1 [lbs] (1)	Unit 2 [lbs] (1)	Unit 3 [lbs] (1)		
Gas	0.0E+00	0.0	0.0	-		
Fuel Oil	4.8E-06	0.0	0.0	-		
Fuel Oil	0.0E+00	-	-	0.0000		
	Total	**0.0**	**0.0**	**0.0000**	**0.1**	
	(4) [Tons/Year]	**0.000**	**0.000**	**0.0000000**	**0.000**	NO
	(5) [Lbs/Day]	**0.0001**	**0.0002**	**0.0000**	**0.0003**	
	[lbs/hr]	**0.0031**	**0.0029**	**0.0000**	**0.0060**	YES

Chromium

	Emission rate per AP42 [lb/mmBtu]	Unit 1 [lbs] (1)	Unit 2 [lbs] (1)	Unit 3 [lbs] (1)		
Gas	0.0E+00	0.0	0.0	-		
Fuel Oil	1.1E-05	0.1	0.1	-		
Fuel Oil	0.0E+00	-	-	0.0000		
	Total	**0.1**	**0.1**	**0.0000**	**0.1**	
	(4) [Tons/Year]	**0.000**	**0.000**	**0.0000000**	**0.000**	NO
	(5) [Lbs/Day]	**0.0003**	**0.0004**	**0.0000**	**0.0006**	
	[lbs/hr]	**0.0071**	**0.0066**	**0.0000**	**0.0137**	YES

Ethyl benzene

	Emission rate per AP42 [lb/mmBtu]	Unit 1 [lbs] (1)	Unit 2 [lbs] (1)	Unit 3 [lbs] (1)		
Gas	3.2E-05	83.8	98.3	-		
Fuel Oil	0.0E+00	0.0	0.0	-		
Fuel Oil	0.0E+00	-	-	0.0000		
	Total	**83.8**	**98.3**	**0.0000**	**182.1**	
	(4) [Tons/Year]	**0.042**	**0.049**	**0.0000000**	**0.091**	NO
	(5) [Lbs/Day]	**0.4410**	**0.4183**	**0.0000**	**0.8593**	
	[lbs/hr]	**0.0250**	**0.0238**	**0.0000**	**0.0488**	NO

Formaldehyde

	Emission rate per AP42 [lb/mmBtu]	Unit 1 [lbs] (1)	Unit 2 [lbs] (1)	Unit 3 [lbs] (1)		
Gas	7.1E-04	1,859.2	2,181.0	-		
Fuel Oil	2.8E-04	1.3	2.2	-		
Fuel Oil	7.9E-05	-	-	0.0374		
	Total	**1,860.5**	**2,183.2**	**0.0374**	**4,043.7**	
	(4) [Tons/Year]	**0.930**	**1.092**	**0.0000187**	**2.022**	YES
	(5) [Lbs/Day]	**9.7919**	**9.2903**	**0.0010**	**19.0832**	
	[lbs/hr]	**0.5531**	**0.5275**	**0.0013**	**1.0819**	YES

Brandywine Power Facility
Emissions Calculation Sheet

Lead

	Emission rate per AP42 [lb/mmBtu]	Unit 1 [lbs] (1)	Unit 2 [lbs] (1)	Unit 3 [lbs] (1)		
Gas	0.0E+00	0.0	0.0	-		
Fuel Oil	1.4E-05	0.1	0.1	-		
Fuel Oil	0.0E+00	-	-	0.0000		
	Total	**0.1**	**0.1**	**0.0000**	**0.2**	
(4)	**[Tons/Year]**	**0.000**	**0.000**	**0.0000000**	**0.000**	NO
(5)	**[Lbs/Day]**	**0.0003**	**0.0005**	**0.0000**	**0.0008**	
	[lbs/hr]	0.0091	0.0084	**0.0000**	**0.0175**	YES

Manganese

	Emission rate per AP42 [lb/mmBtu]	Unit 1 [lbs] (1)	Unit 2 [lbs] (1)	Unit 3 [lbs] (1)		
Gas	0.0E+00	0.0	0.0	-		
Fuel Oil	7.9E-04	3.7	6.2	-		
Fuel Oil	0.0E+00	-	-	0.0000		
	Total	**3.7**	**6.2**	**0.0000**	**9.9**	
(4)	**[Tons/Year]**	**0.002**	**0.003**	**0.0000000**	**0.005**	NO
(5)	**[Lbs/Day]**	**0.0194**	**0.0265**	**0.0000**	**0.0459**	
	[lbs/hr]	0.5117	0.4730	**0.0000**	**0.9848**	YES

Mercury

	Emission rate per AP42 [lb/mmBtu]	Unit 1 [lbs] (1)	Unit 2 [lbs] (1)	Unit 3 [lbs] (1)		
Gas	0.0E+00	0.0	0.0	-		
Fuel Oil	1.2E-06	0.006	0.009	-		
Fuel Oil	0.0E+00	-	-	0.0000		
	Total	**0.01**	**0.01**	**0.0000**	**0.0**	
(4)	**[Tons/Year]**	**0.000**	**0.000**	**0.0000000**	**0.000**	NO
(5)	**[Lbs/Day]**	**0.0000**	**0.0000**	**0.0000**	**0.0001**	
	[lbs/hr]	0.0008	0.0007	**0.0000**	**0.0015**	YES

Napthalene (dupilcated under PAHs)

	Emission rate per AP42 [lb/mmBtu]	Unit 1 [lbs] (1)	Unit 2 [lbs] (1)	Unit 3 [lbs] (1)		
Gas	1.3E-06	3.4	4.0	-		
Fuel Oil	3.5E-05	0.2	0.3	-		
Fuel Oil	1.3E-04	-	-	0.0616		
	Total	**3.6**	**4.3**	**0.0616**	**7.9**	
(4)	**[Tons/Year]**	**0.002**	**0.002**	**0.0000308**	**0.004**	NO
(5)	**[Lbs/Day]**	**0.0188**	**0.0182**	**0.0016**	**0.0386**	
	[lbs/hr]	0.0011	0.0010	**0.0022**	**0.0043**	NO

Nickel

	Emission rate per AP42 [lb/mmBtu]	Unit 1 [lbs] (1)	Unit 2 [lbs] (1)	Unit 3 [lbs] (1)		
Gas	0.0E+00	0.0	0.0	-		
Fuel Oil	4.6E-06	0.0	0.0	-		
Fuel Oil	0.0E+00	-	-	0.0000		
	Total	**0.0**	**0.0**	**0.0000**	**0.1**	
(4)	**[Tons/Year]**	**0.000**	**0.000**	**0.0000000**	**0.000**	NO
(5)	**[Lbs/Day]**	**0.0001**	**0.0002**	**0.0000**	**0.0003**	
	[lbs/hr]	0.0030	0.0028	**0.0000**	**0.0057**	YES

POM (PAHs)

	Emission rate per AP42 [lb/mmBtu]	Unit 1 [lbs] (1)	Unit 2 [lbs] (1)	Unit 3 [lbs] (1)		
Gas	2.2E-06	5.8	6.8	-		
Fuel Oil	4.0E-05	0.2	0.3	-		
Fuel Oil	2.1E-04	-	-	0.1004		
	Total	**5.9**	**7.1**	**0.1004**	**13.1**	
(4)	**[Tons/Year]**	**0.003**	**0.004**	**0.0000502**	**0.007**	NO
(5)	**[Lbs/Day]**	**0.0313**	**0.0301**	**0.0026**	**0.0640**	
	[lbs/hr]	0.0018	0.0017	**0.0036**	**0.0071**	NO

Propylene oxide

	Emission rate per AP42 [lb/mmBtu]	Unit 1 [lbs] (1)	Unit 2 [lbs] (1)	Unit 3 [lbs] (1)		
Gas	2.9E-05	75.9	89.1	-		
Fuel Oil	0.0E+00	0.0	0.0	-		
Fuel Oil	0.0E+00	-	-	0.0000		
	Total	**75.9**	**89.1**	**0.0000**	**165.0**	
(4)	**[Tons/Year]**	**0.038**	**0.045**	**0.0000000**	**0.083**	NO
(5)	**[Lbs/Day]**	**0.3997**	**0.3791**	**0.0000**	**0.7788**	
	[lbs/hr]	0.0226	0.0216	**0.0000**	**0.0442**	NO

Selenium

	Emission rate per AP42 [lb/mmBtu]	Unit 1 [lbs] (1)	Unit 2 [lbs] (1)	Unit 3 [lbs] (1)		
Gas	0.0E+00	0.0	0.0	-		
Fuel Oil	2.5E-05	0.1	0.2	-		
Fuel Oil	0.0E+00	-	-	0.0000		
	Total	**0.12**	**0.20**	**0.0000**	**0.3**	
(4)	**[Tons/Year]**	**0.000**	**0.000**	**0.0000000**	**0.000**	
(5)	**[Lbs/Day]**	**0.0006**	**0.0008**	**0.0000**	**0.0015**	
	[lbs/hr]	0.0162	0.0150	**0.0000**	**0.0312**	YES

Toluene

	Emission rate per AP42 [lb/mmBtu]	Unit 1 [lbs] (1)	Unit 2 [lbs] (1)	Unit 3 [lbs] (1)		
Gas	1.3E-04	340.4	399.3	-		
Fuel Oil	0.0E+00	0.0	0.0	-		
Fuel Oil	2.8E-04	-	-	0.1331		
	Total	**340.4**	**399.3**	**0.1331**	**739.9**	
(4)	**[Tons/Year]**	**0.170**	**0.200**	**0.0000666**	**0.370**	NO
(5)	**[Lbs/Day]**	**1.7916**	**1.6993**	**0.0035**	**3.4945**	
	[lbs/hr]	0.1014	0.0968	**0.0048**	**0.2030**	NO

Xylenes

	Emission rate per AP42 [lb/mmBtu]	Unit 1 [lbs] (1)	Unit 2 [lbs] (1)	Unit 3 [lbs] (1)		
Gas	6.4E-05	167.6	196.6	-		
Fuel Oil	0.0E+00	0.0	0.0	-		
Fuel Oil	1.9E-04	-	-	0.0914		
	Total	**167.6**	**196.6**	**0.0914**	**364.3**	
(4)	**[Tons/Year]**	**0.084**	**0.098**	**0.0000457**	**0.182**	NO
(5)	**[Lbs/Day]**	**0.8820**	**0.8366**	**0.0024**	**1.7210**	
	[lbs/hr]	0.0499	0.0477	**0.0033**	**0.1009**	NO

Brandywine Power Facility
Emissions Calculation Sheet

Acenaphthene

	Emission rate per AP42 [lb/mmBtu]	Unit 3 [lbs] (1)	
Fuel Oil	4.7E-06	0.0022	
	Total	**0.0022**	
	(4) **[Tons/Year]**	**0.0000011**	**NO**
	(5) **[Lbs/Day]**	**0.0001**	
	[lbs/hr]	**0.0001**	**NO**

Acenaphthylene

	Emission rate per AP42 [lb/mmBtu]	Unit 3 [lbs] (1)	
Fuel Oil	9.2E-06	0.0044	
	Total	**0.0044**	
	(4) **[Tons/Year]**	**0.0000022**	**NO**
	(5) **[Lbs/Day]**	**0.0001**	
	[lbs/hr]	**0.0002**	**NO**

Anthracene

	Emission rate per AP42 [lb/mmBtu]	Unit 3 [lbs] (1)	
Fuel Oil	1.2E-06	0.0006	
	Total	**0.0006**	
	(4) **[Tons/Year]**	**0.0000003**	**NO**
	(5) **[Lbs/Day]**	**0.0000**	
	[lbs/hr]	**0.000021**	**NO**

Benz(a)anthracene

	Emission rate per AP42 [lb/mmBtu]	Unit 3 [lbs] (1)	
Fuel Oil	6.2E-07	0.0003	
	Total	**0.0003**	
	(4) **[Tons/Year]**	**0.0000001**	**NO**
	(5) **[Lbs/Day]**	**0.000008**	
	[lbs/hr]	**0.000011**	**NO**

Benzo(a)pyrene

	Emission rate per AP42 [lb/mmBtu]	Unit 3 [lbs] (1)	
Fuel Oil	2.6E-07	0.0001	
	Total	**0.0001**	
	(4) **[Tons/Year]**	**0.0000001**	**NO**
	(5) **[Lbs/Day]**	**0.000003**	
	[lbs/hr]	**0.000004**	**NO**

Benzo(b)fluoranthene

	Emission rate per AP42 [lb/mmBtu]	Unit 3 [lbs] (1)	
Fuel Oil	1.1E-06	0.0005	
	Total	**0.0005**	
	(4) **[Tons/Year]**	**0.0000003**	**NO**
	(5) **[Lbs/Day]**	**0.00001**	
	[lbs/hr]	**0.00072**	**NO**

Benzo(g,h,I)perylene

	Emission rate per AP42 [lb/mmBtu]	Unit 3 [lbs] (1)	
Fuel Oil	5.6E-07	0.0003	
	Total	**0.0003**	
	(4) **[Tons/Year]**	**0.0000001**	**NO**
	(5) **[Lbs/Day]**	**0.000007**	
	[lbs/hr]	**0.000009**	**NO**

Benzo(k)fluoranthene

	Emission rate per AP42 [lb/mmBtu]	Unit 3 [lbs] (1)	
Fuel Oil	2.2E-07	0.0001	
	Total	**0.0001**	
	(4) **[Tons/Year]**	**0.0000001**	**NO**
	(5) **[Lbs/Day]**	**0.000003**	
	[lbs/hr]	**0.000004**	**NO**

Chrysene

	Emission rate per AP42 [lb/mmBtu]	Unit 3 [lbs] (1)	
Fuel Oil	1.5E-06	0.0007	
	Total	**0.0007**	
	(4) **[Tons/Year]**	**0.0000004**	**NO**
	(5) **[Lbs/Day]**	**0.00002**	
	[lbs/hr]	**0.00003**	**NO**

Dibenzo(a,h)anthracene

	Emission rate per AP42 [lb/mmBtu]	Unit 3 [lbs] (1)	
Fuel Oil	3.5E-07	0.0002	
	Total	**0.0002**	
	(4) **[Tons/Year]**	**0.0000001**	**NO**
	(5) **[Lbs/Day]**	**0.000004**	
	[lbs/hr]	**0.000006**	**NO**

Fluoranthene

	Emission rate per AP42 [lb/mmBtu]	Unit 3 [lbs] (1)	
Fuel Oil	4.0E-06	0.0019	
	Total	**0.0019**	
	(4) **[Tons/Year]**	**0.0000010**	**NO**
	(5) **[Lbs/Day]**	**0.0001**	
	[lbs/hr]	**0.0001**	**NO**

Fluorene

	Emission rate per AP42 [lb/mmBtu]	Unit 3 [lbs] (1)	
Fuel Oil	1.3E-05	0.0061	
	Total	**0.0061**	
	(4) **[Tons/Year]**	**0.0000030**	**NO**
	(5) **[Lbs/Day]**	**0.000160**	
	[lbs/hr]	**0.0002**	**NO**

Ideno(1,2,3-cd)pyrene

	Emission rate per AP42 [lb/mmBtu]	Unit 3 [lbs] (1)	
Fuel Oil	4.1E-07	0.0002	
	Total	**0.0002**	
	(4) **[Tons/Year]**	**0.0000001**	**NO**
	(5) **[Lbs/Day]**	**0.000005**	
	[lbs/hr]	**0.000007**	**NO**

Phenanthrene

	Emission rate per AP42 [lb/mmBtu]	Unit 3 [lbs] (1)	
Fuel Oil	4.1E-05	0.0193	
	Total	**0.0193**	
	(4) **[Tons/Year]**	**0.0000097**	**NO**
	(5) **[Lbs/Day]**	**0.0005**	
	[lbs/hr]	**0.0007**	**NO**

Pyrene

	Emission rate per AP42 [lb/mmBtu]	Unit 3 [lbs] (1)	
Fuel Oil	3.7E-06	0.0018	
	Total	**0.0018**	
	(4) **[Tons/Year]**	**0.0000009**	**NO**
	(5) **[Lbs/Day]**	**0.0000**	
	[lbs/hr]	**0.0001**	**NO**

Brandywine Power Facility
Emissions Calculation Sheet

(1) Pounds of emitted substance was calculated by multiplying the rate of emission (in pounds/mmBtu) by the total heat input (in mmBtu).
(2) The NOx pounds were based on the totals reported by the CEM DAHS system.
(3) The NOx lbs/hr number is the year's total NOx pounds divided by the number of operating hours (both figures are as reported by the CEMS DAHS).
(4) Tons/year of an emitted pollutant was calculated by:
- multiplying the emission rate by either the operating hours or the heat input, for each type of fuel, for each unit.
- summing the pounds of emissions for each fuel into the "Total" row for each unit.
- the total for each pollutant is divided by 2000 to get a "Tons/Yr" figure.

(5) Pounds/day was calculated by dividing the annual total emissions by the number of operating days recorded for the year.
(6) The Ozone Season data (TOSD) for VOCs was computed using the heat input figures for that period of the year only (May 1st-September 30th).
(7) Operating hours are as reported to the EPA-ECMPS.
(9) The Ozone Season data (TOSD) pounds/day figures for NOx were determined by dividing the NOx emissions reported by the CEMS DAHS for the Ozone Season by the number of actual operating days during the Ozone Season.
(10) Heat input values (in mmBtu) used for calculation are as-reported by the plant's CEMS-DAHS to the EPA-ECMPS.
(11) Source: CAT Performance Data Sheet DM8854
(12) Pounds of emitted substance was calculated by multiplying the rate of emission (in pounds/hour) by the total annual run hours.

user-entered data (most from CEMS-DAHS or EPA-ECMPS reports)
data forwarded from another worksheet
AP42 factor; see section 3.1, Stationary Gas Turbines, tables 3.1-1, 3.1-2a, & 3.1-5 and section 3.4, Large Stationary Diesel Engines, tables 3.4-
Source: CAT Performance Data Sheet DM8854
Source: 40CFR98 Tables C-1 and C-2

See the last page of this spreadsheet for information as to a change in emission rates for the 2007 certification report.
The Run Days sheet must be updated annually.

Form 3: PM Total

EMISSIONS CERTIFICATION REPORT

Facility name: Brandywine Power Facility **Pollutant:** Particulate Matter - Total **Calendar Year :** 2017

Registration No./ Equip. Description	SCC Number	Fuel	type	Primary (total)		Filterable		Condensable		Operation	Estimate Method
				[tons/yr]	[lbs/day]	[tons/yr]	[lbs/day]	[tons/yr]	[lbs/day]	[days/yr]	
5-0844	20100201	natural gas	s	8.6	91.0	2.5	26.2	6.2	64.8	190	C3
Unit 1/A GT			f	0	0	0	0	0	0		C4
5-0845	20100201	natural gas	s	10.1	86.3	2.9	24.8	7.2	61.4	235	C3
Unit 2/B GT			f	0	0	0	0	0	0		C4
5-0844	20100201	no. 2 distillate oil	s	0.0	0.3	0.0	0.1	0.0	0.2		C3
Unit 1/A GT			f	0	0	0	0	0	0		C4
5-0845	20100201	no. 2 distillate oil	s	0.0	0.4	0.0	0.1	0.0	0.2		C3
Unit 2/B GT			f	0	0	0	0	0	0		C4
9-1465	20100102	no. 2 distillate oil	s	0.017	0.9	0.015	0.77	0.002	0.10	38	C3
Unit 3/ Emerg Diesel			f	0	0	0	0	0	0		C4
Totals				18.9	178.8	5.4	52.0	13.4	126.7		

s - Stack Emissions f- Fugitive Emissions Daily emissions (lbs/dy) are lbs/operating day of the source

Note 1: Per AP42, section 3.1.3.3, all condensable PM is consdiered to be less that 1.0 um in diameter, and is hence reported under the PM2.5 category.

Fuel: Include emissions for each fuel used. If more than one fuel is used, calculate and list emissions separately for each fuel.

Emission Estimation Method

A1 - U.S. EPA Reference Method
A2 - Other Particulate Sampling train
A3 - Liquid Absorption Technique
A5 - Freezing-Out Technique
A9 - Other, Specify

C1 - User calculated based on source test or other measurements
C2 - User calculated based on material balance using engineering knowledge of the process
C3 - User calculated based on AP-42
C4 - User calculated by best guess/engineering judgement

C5 - User calculated based on a State or local agency emission factor
C6 - New construction, not operational
C7 - Source closed, operation ceased
C8 - Computer calculated based on standard

Form 3: PM 2.5

EMISSIONS CERTIFICATION REPORT

Facility name: Brandywine Power Facility **Pollutant: Particulate Matter - 2.5** **Calendar Year : 2017**

Registration No./ Equip. Description	SCC Number	Fuel	type	Primary (total)		Filterable		Condensable		Operation	Estimate Method
				[tons/yr]	[lbs/day]	[tons/yr]	[lbs/day]	[tons/yr]	[lbs/day]	[days/yr]	
5-0844	20100201	natural gas	s	8.6	91.0	2.5	26.2	6.2	64.8	190	C3
Unit 1/A GT			f	0	0	0	0	0	0		C4
5-0845	20100201	natural gas	s	10.1	86.3	2.9	24.8	7.2	61.4	235	C3
Unit 2/B GT			f	0	0	0	0	0	0		C4
5-0844	20100201	no. 2 distillate oil	s	0.0	0.3	0.0	0.1	0.0	0.2		C3
Unit 1/A GT			f	0	0	0	0	0	0		C4
5-0845	20100201	no. 2 distillate oil	s	0.0	0.4	0.0	0.1	0.0	0.2		C3
Unit 2/B GT			f	0	0	0	0	0	0		C4
9-1465	20100102	no. 2 distillate oil	s	0.017	0.9	0.015	0.77	0.002	0.10	38	C3
Unit 3/ Emerg Diesel			f	0	0	0	0	0	0		C4
Totals				18.9	178.8	5.4	52.0	13.4	126.7		

s - Stack Emissions f- Fugitive Emissions Daily emissions (lbs/dy) are lbs/operating day of the source

Note 1: Per AP42, section 3.1.3.3, all condensable PM is consdiered to be less that 1.0 um in diameter, and is hence reported under the PM2.5 category.

Fuel: Include emissions for each fuel used. If more than one fuel is used, calculate and list emissions separately for each fuel.

Emission Estimation Method

A1 - U.S. EPA Reference Method
A2 - Other Particulate Sampling train
A3 - Liquid Absorption Technique
A5 - Freezing-Out Technique
A9 - Other, Specify

C1 - User calculated based on source test or other measurements
C2 - User calculated based on material balance using engineering knowledge of the process
C3 - User calculated based on AP-42
C4 - User calculated by best guess/engineering judgement

C5 - User calculated based on a State or local agency emission factor
C6 - New construction, not operational
C7 - Source closed, operation ceased
C8 - Computer calculated based on standard

FORM 2:

CRITERIA AIR POLLUTANTS
EMISSIONS CERTIFICATION REPORT

Facility name: Brandywine Power Facility **Pollutant:** Nitrogen Oxides **Calendar Year :** 2017

Registration No./ Equip. Description	SCC Number	Fuel	type	Actual Emssions		Operating Schedule (Actual)					TOSD	Operating Schedule			Estimate Method
				[tons/yr]	[lbs/day]	[hrs/day]	Start	End	[days/wk]	[days/yr]	[lbs/dy]	[hrs/day]	Start	End	
5-0844	20100201	natural gas	s	33.5	352.8	17.7	0:01	24:00	3.7	190	163.3	17.2	0:01	24:00	C1
Unit 1/A GT			f	0	0						0				C4
5-0845	20100201	natural gas	s	42.1	358.1	17.6	0:01	24:00	4.5	235	342.6	17.1	0:01	24:00	C1
Unit 2/B GT			f	0	0						0				C4
5-0844	20100201	no. 2 distillate oil	s	1.1	11.5	17.7	0:01	24:00	3.7		4.0	17.2	0:01	24:00	C1
Unit 1/A GT			f	0	0						0				C4
5-0845	20100201	no. 2 distillate oil	s	1.6	13.3	17.6	0:01	24:00	4.5		10.6	17.1	0:01	24:00	C1
Unit 2/B GT			f	0	0						0				C4
9-1465	20100102	no. 2 distillate oil	s	0.4	23.0	0.7	0:01	24:00	0.7	38	23.6	0.7	0:01	24:00	C1
Unit 3/ Emerg Diesel			f	0	0						0.0				C4
Totals				78.7	758.8						544.1				

s - Stack Emissions f- Fugitive Emissions Daily emissions (lbs/dy) are lbs/operating day of the source

TOSD - Typical Ozone Season Day means a typical day of that period of the year during which conditions for photochemical conditions are most favorable. which is generally during substained periods of direct sunlight and warm temperatures (April-September). This section needs to be completed only for VOC and NOx sources.

Fuel: Include emissions for each fuel used. If more than one fuel is used, calculate and list emissions separately for each fuel.

Emissions Estimation Method

A1 - U.S. EPA Reference Method
A2 - Other Particulate Sampling train
A3 - Liquid Absorption Technique
A5 - Freezing-Out Technique
A9 - Other. Specify

C1 - User calculated based on source test or other measurements
C2 - User calculated based on material balance using engineering knowledge of the process
C3 - User calculated based on AP-42
C4 - User calculated by best guess/engineering judgement

C5 - User calculated based on a State or local agency emission factor
C6 - New construction, not operational
C7 - Source closed, operation ceased
C8 - Computer calculated based on standard

PLEASE NOTE: Be sure to attach all data and calculations necessary to support the emissions figures shown above.

FORM 2:

CRITERIA AIR POLLUTANTS
EMISSIONS CERTIFICATION REPORT

Facility name: Brandywine Power Facility **Pollutant:** Carbon Monoxide **Calendar Year :** 2017

Registration No./ Equip. Description	SCC Number	Fuel	type	Actual Emssions		Operating Schedule (Actual)					TOSD	Operating Schedule			Estimate Method
				[tons/yr]	[lbs/day]	[hrs/day]	Start	End	[days/wk]	[days/yr]	[lbs/dy]	[hrs/day]	Start	End	
5-0844	20100201	natural gas	s	19.6	206.7	17.7	0:01	24:00	3.7	190	204.6	17.2	0:01	24:00	C3
Unit 1/A GT			f	0	0						0				C4
5-0845	20100201	natural gas	s	23.0	196.1	17.6	0:01	24:00	4.5	235	194.1	17.1	0:01	24:00	C3
Unit 2/B GT			f	0	0						0				C4
5-0844	20100201	no. 2 distillate oil	s	0.2	1.9	17.7	0:01	24:00	3.7		1.9	17.2	0:01	24:00	C3
Unit 1/A GT			f	0	0						0				C4
5-0845	20100201	no. 2 distillate oil	s	0.3	2.5	17.6	0:01	24:00	4.5		1.8	17.1	0:01	24:00	C3
Unit 2/B GT			f	0	0						0				C4
9-1465	20100102	no. 2 distillate oil	s	0.028	1.5	0.7	0:01	24:00	0.7	38	1.5	0.7	0:01	24:00	C1
Unit 3/ Emerg Diesel			f	0	0						0				C4
Totals				43.2	408.7						403.9				

s - Stack Emissions f- Fugitive Emissions Daily emissions (lbs/dy) are lbs/operating day of the source

TOSD - Typical Ozone Season Day means a typical day of that period of the year during which conditions for photochemical conditions are most favorable. which is generally during substained periods of direct sunlight and warm temperatures (April-September). This section needs to be completed only for VOC and NOx sources.

Emissions Estimation Method

A1 - U.S. EPA Reference Method
A2 - Other Particulate Sampling train
A3 - Liquid Absorption Technique
A5 - Freezing-Out Technique
A9 - Other, Specify

C1 = User calculated based on source test or other measurements
C2 = User calculated based on material balance using engineering knowledge of the process
C3 = User calculated based on AP-42
C4 = User calculated by best guess/engineering judgement

C5 - User calculated based on a State or local agency emission factor
C6 - New construction. not operational
C7 - Source closed. operation ceased
C8 - Computer calculated based on standard

PLEASE NOTE: Be sure to attach all data and calculations necessary to support the emissions figures shown above.

FORM 2:

CRITERIA AIR POLLUTANTS
EMISSIONS CERTIFICATION REPORT

Facility name: Brandywine Power Facility **Pollutant: Volatile Organic Compounds** **Calendar Year : 2017**

Registration No./ Equip. Description	SCC Number	Fuel	type	Actual Emssions		Operating Schedule (Actual)					TOSD	Operating Schedule			Estimate Method
				[tons/yr]	[lbs/day]	[hrs/day]	Start	End	[days/wk]	[days/yr]	[lbs/dy]	[hrs/day]	Start	End	
5-0844	20100201	natural gas	s	2.7	28.9	17.7	0:01	24:00	3.7	190	28.6	17.2	0:01	24:00	C3
Unit 1/A GT			f	0	0						0				C4
5-0845	20100201	natural gas	s	3.2	27.5	17.6	0:01	24:00	4.5	235	27.2	17.1	0:01	24:00	C3
Unit 2/B GT			f	0	0						0				C4
5-0844	20100201	no. 2 distillate oil	s	0.00	0.0	17.7	0:01	24:00	3.7		0.01	17.2	0:01	24:00	C3
Unit 1/A GT			f	0	0						0				C4
5-0845	20100201	no. 2 distillate oil	s	0.00	0.0	17.6	0:01	24:00	4.5		0.01	17.1	0:01	24:00	C3
Unit 2/B GT			f	0	0						0				C4
9-1465	20100102	no. 2 distillate oil	s	0.00	0.2	0.7	0:01	24:00	0.7	38	0.2	0.7	0:01	24:00	C1
Unit 3/ Emerg Diesel			f	0	0						0				C4
Totals				6.0	56.6						56.0				

s - Stack Emissions f- Fugitive Emissions Daily emissions (lbs/dy) are lbs/operating day of the source

TOSD - Typical Ozone Season Day means a typical day of that period of the year during which conditions for photochemical conditions are most favorable, which is generally during substained periods of direct sunlight and warm temperatures (April-September). This section needs to be completed only for VOC and NOx sources.

Emissions Estimation Method

A1 - U.S. EPA Reference Method
A2 - Other Particulate Sampling train
A3 - Liquid Absorption Technique
A5 - Freezing-Out Technique
A9 - Other, Specify

C1 = User calculated based on source test or other measurements
C2 = User calculated based on material balance using engineering knowledge of the process
C3 = User calculated based on AP-42
C4 = User calculated by best guess/engineering judgement

C5 - User calculated based on a State or local agency emission factor
C6 - New construction, not operational
C7 - Source closed, operation ceased
C8 - Computer calculated based on standard

PLEASE NOTE: Be sure to attach all data and calculations necessary to support the emissions figures shown above.

FORM 2:

CRITERIA AIR POLLUTANTS
EMISSIONS CERTIFICATION REPORT

Facility name: Brandywine Power Facility **Pollutant:** Sulfur Oxides **Calendar Year :** 2017

Registration No./ Equip. Description	SCC Number	Fuel	type	Actual Emssions		Operating Schedule (Actual)					TOSD	Operating Schedule			Estimate Method
				[tons/yr]	[lbs/day]	[hrs/day]	Start	End	[days/wk]	[days/yr]	[lbs/dy]	[hrs/day]	Start	End	
5-0844	20100201	natural gas	s	0.8	8.3	17.7	0:01	24:00	3.7	190	8.2	17.2	0:01	24:00	C3
Unit 1/A GT			f	0	0						0				C4
5-0845	20100201	natural gas	s	0.9	7.8	17.6	0:01	24:00	4.5	235	7.8	17.1	0:01	24:00	C3
Unit 2/B GT			f	0	0						0				C4
5-0844	20100201	no. 2 distillate oil	s	0.0	0.0	17.7	0:01	24:00	3.7		0.0	17.2	0:01	24:00	C3
Unit 1/A GT			f	0	0						0				C4
5-0845	20100201	no. 2 distillate oil	s	0.0	0.0	17.6	0:01	24:00	4.5		0.0	17.1	0:01	24:00	C3
Unit 2/B GT			f	0	0						0				C4
9-1465	20100102	no. 2 distillate oil	s	0.00021	0.011	0.7	0:01	24:00	0.7	38	0.011	0.7	0:01	24:00	C3
Unit 3/ Emerg Diesel			f	0	0						0				C4
Totals				1.7	16.2						16.0				

s - Stack Emissions f- Fugitive Emissions Daily emissions (lbs/dy) are lbs/operating day of the source

TOSD - Typical Ozone Season Day means a typical day of that period of the year during which conditions for photochemical conditions are most favorable, which is generally during substained periods of direct sunlight and warm temperatures (April-September). This section needs to be completed only for VOC and NOx sources.

Emissions Estimation Method

A1 - U.S. EPA Reference Method
A2 - Other Particulate Sampling train
A3 - Liquid Absorption Technique
A5 - Freezing-Out Technique
A9 - Other. Specify

C1 - User calculated based on source test or other measurements
C2 - User calculated based on material balance using engineering knowledge of the process
C3 - User calculated based on AP-42
C4 - User calculated by best guess/engineering judgement

C5 - User calculated based on a State or local agency emission factor
C6 - New construction, not operational
C7 - Source closed, operation ceased
C8 - Computer calculated based on standard

PLEASE NOTE: Be sure to attach all data and calculations necessary to support the emissions figures shown above.

Form 4:

TOXIC AIR POLLUTANTS

EMISSIONS CERTIFICATION REPORT

Facility name: Brandywine Power Facility **Pollutant:** Acetaldehyde **Calendar Year :** 2017

Registration No./ Equip. Description	Actual Emissions [tons/year]	[lbs/day]	[lbs/hr]	Control Device	Efficiency [%]
5-0844 Unit 1/A GT	0.052	0.551	0.031	uncontrolled /Gas operation only	N/A
5-0845 Unit 2/B GT	0.061	0.523	0.030	uncontrolled /Gas operation only	N/A
9-1465 Unit 3/ Emerg Diesel	0.000006	0.0003	0.00043	uncontrolled	N/A
Totals	0.11	1.07	0.06		

Note 1: Emissions must be broken down by equipment registration number.

Form 4:

TOXIC AIR POLLUTANTS

EMISSIONS CERTIFICATION REPORT

Facility name: **Brandywine Power Facility** **Pollutant:** **Acrolein** **Calendar Year :** **2017**

Registration No./ Equip. Description	Actual Emissions [tons/year]	[lbs/day]	[lbs/hr]	Control Device	Efficiency [%]
5-0844 Unit 1/A GT	0.008	0.088	0.005	uncontrolled /Gas operation only	N/A
5-0845 Unit 2/B GT	0.010	0.084	0.005	uncontrolled /Gas operation only	N/A
9-1465 Unit 3/ Emerg Diesel	0.000002	0.0001	0.0001	uncontrolled	N/A
Totals	0.02	0.17	0.01		

Note 1: Emissions must be broken down by equipment registration number.

Form 4:

TOXIC AIR POLLUTANTS

EMISSIONS CERTIFICATION REPORT

Facility name: Brandywine Power Facility **Pollutant:** Arsenic **Calendar Year :** 2017

Registration No./ Equip. Description	Actual Emissions [tons/year]	[lbs/day]	[lbs/hr]	Control Device	Efficiency [%]
5-0844 Unit 1/A GT	0.000026	0.000	0.007	uncontrolled /fuel oil operation only	N/A
5-0845 Unit 2/B GT	0.000043	0.000	0.007	uncontrolled /fuel oil operation only	N/A
Totals	0.00007	0.00	0.014		

Note 1: Emissions must be broken down by equipment registration number.

Form 4:

TOXIC AIR POLLUTANTS

EMISSIONS CERTIFICATION REPORT

Facility name: Brandywine Power Facility **Pollutant:** Benzene **Calendar Year :** 2017

Registration No./ Equip. Description	Actual Emissions [tons/year]	[lbs/day]	[lbs/hr]	Control Device	Efficiency [%]
5-0844 Unit 1/A GT - gas	0.016	0.17	0.0094	uncontrolled	N/A
5-0845 Unit 2/B GT - gas	0.018	0.16	0.0089	uncontrolled	N/A
total	**0.034**	**0.32**	**0.018**		
5-0844 Unit 1/A GT - oil	0.00013	0.0013	0.036	uncontrolled	N/A
5-0845 Unit 2/B GT - oil	0.00022	0.0018	0.033	uncontrolled	N/A
total	**0.0003**	**0.003**	**0.069**		
9-1465 Unit 3/ Emerg Diesel	**0.00018**	**0.010**	**0.0132**	uncontrolled	N/A

Note 1: Emissions must be broken down by equipment registration number.

Form 4:

TOXIC AIR POLLUTANTS

EMISSIONS CERTIFICATION REPORT

Facility name: Brandywine Power Facility **Pollutant:** Beryllium **Calendar Year :** 2017

Registration No./ Equip. Description	Actual Emissions [tons/year]	[lbs/day]	[lbs/hr]	Control Device	Efficiency [%]
5-0844 Unit 1/A GT	0.0000007	0.00	0.00020	uncontrolled /fuel oil operation only	N/A
5-0845 Unit 2/B GT	0.0000012	0.000	0.000	uncontrolled /fuel oil operation only	N/A
Totals	0.0000019	0.00	0.00039		

Note 1: Emissions must be broken down by equipment registration number.

Form 4:

TOXIC AIR POLLUTANTS

EMISSIONS CERTIFICATION REPORT

Facility name: Brandywine Power Facility **Pollutant:** 1,3-Butadiene **Calendar Year :** 2017

Registration No./ Equip. Description	Actual Emissions [tons/year]	[lbs/day]	[lbs/hr]	Control Device	Efficiency [%]
5-0844 Unit 1/A GT - gas	0.00056	0.0059	0.00034	uncontrolled	N/A
5-0845 Unit 2/B GT - gas	0.00066	0.0056	0.00032	uncontrolled	N/A
total	**0.0012**	**0.0115**	**0.00066**		
5-0844 Unit 1/A GT - oil	0.00004	0.0004	0.010	uncontrolled	N/A
5-0845 Unit 2/B GT - oil	0.00006	0.0005	0.0096	uncontrolled	N/A
total	**0.00010**	**0.0009**	**0.020**		

Note 1: Emissions must be broken down by equipment registration number.

Form 4:

TOXIC AIR POLLUTANTS

EMISSIONS CERTIFICATION REPORT

Facility name: Brandywine Power Facility **Pollutant:** Cadmium **Calendar Year :** 2017

Registration No./ Equip. Description	Actual Emissions [tons/year]	[lbs/day]	[lbs/hr]	Control Device	Efficiency [%]
5-0844 Unit 1/A GT	0.000011	0.00	0.0031	uncontrolled /fuel oil operation only	N/A
5-0845 Unit 2/B GT	0.000019	0.00	0.0029	uncontrolled /fuel oil operation only	N/A
Totals	0.0000301	0.00	0.00598		

Note 1: Emissions must be broken down by equipment registration number.

Form 4:

TOXIC AIR POLLUTANTS

EMISSIONS CERTIFICATION REPORT

Facility name: Brandywine Power Facility **Pollutant:** Chromium **Calendar Year :** 2017

Registration No./ Equip. Description	Actual Emissions [tons/year]	[lbs/day]	[lbs/hr]	Control Device	Efficiency [%]
5-0844 Unit 1/A GT	0.000026	0.00	0.0071	uncontrolled /fuel oil operation only	N/A
5-0845 Unit 2/B GT	0.000043	0.00	0.0066	uncontrolled /fuel oil operation only	N/A
Totals	0.0000690	0.00	0.01371		

Note 1: Emissions must be broken down by equipment registration number.

Form 4:

TOXIC AIR POLLUTANTS

EMISSIONS CERTIFICATION REPORT

Facility name: Brandywine Power Facility **Pollutant:** Formaldehyde **Calendar Year :** 2017

Registration No./ Equip. Description	Actual Emissions [tons/year]	[lbs/day]	[lbs/hr]	Control Device	Efficiency [%]
5-0844 Unit 1/A GT - gas	0.93	9.8	0.55	uncontrolled	N/A
5-0845 Unit 2/B GT - gas	1.09	9.3	0.53	uncontrolled	N/A
total	**2.0**	**19.1**	**1.1**		
5-0844 Unit 1/A GT - oil	0.00065	0.0069	0.181	uncontrolled	N/A
5-0845 Unit 2/B GT - oil	0.00110	0.0094	0.1677	uncontrolled	N/A
total	**0.0018**	**0.016**	**0.35**		
9-1465 Unit 3/ Emerg Diesel	**0.00002**	**0.0010**	**0.001**	uncontrolled	N/A

Note 1: Emissions must be broken down by equipment registration number.

Form 4:

TOXIC AIR POLLUTANTS

EMISSIONS CERTIFICATION REPORT

Facility name: Brandywine Power Facility **Pollutant:** Lead **Calendar Year :** 2017

Registration No./ Equip. Description	Actual Emissions [tons/year]	[lbs/day]	[lbs/hr]	Control Device	Efficiency [%]
5-0844 Unit 1/A GT	0.00003	0.00	0.0091	uncontrolled /fuel oil operation only	N/A
5-0845 Unit 2/B GT	0.00006	0.00	0.0084	uncontrolled /fuel oil operation only	N/A
Totals	0.00009	0.00	0.017		

Note 1: Emissions must be broken down by equipment registration number.

Form 4:

TOXIC AIR POLLUTANTS

EMISSIONS CERTIFICATION REPORT

Facility name: Brandywine Power Facility **Pollutant:** Manganese **Calendar Year :** 2017

Registration No./ Equip. Description	Actual Emissions [tons/year]	[lbs/day]	[lbs/hr]	Control Device	Efficiency [%]
5-0844 Unit 1/A GT	0.00184	0.02	0.5117	uncontrolled /fuel oil operation only	N/A
5-0845 Unit 2/B GT	0.00311	0.03	0.4730	uncontrolled /fuel oil operation only	N/A
Totals	0.00495	0.05	0.985		

Note 1: Emissions must be broken down by equipment registration number.

Form 4:

TOXIC AIR POLLUTANTS

EMISSIONS CERTIFICATION REPORT

Facility name: Brandywine Power Facility **Pollutant:** Mercury **Calendar Year :** 2017

Registration No./ Equip. Description	Actual Emissions [tons/year]	[lbs/day]	[lbs/hr]	Control Device	Efficiency [%]
5-0844 Unit 1/A GT	0.000003	0.00	0.00078	uncontrolled /fuel oil operation only	N/A
5-0845 Unit 2/B GT	0.000005	0.00	0.00072	uncontrolled /fuel oil operation only	N/A
Totals	0.000008	0.00	0.0015		

Note 1: Emissions must be broken down by equipment registration number.

Form 4:

TOXIC AIR POLLUTANTS

EMISSIONS CERTIFICATION REPORT

Facility name: Brandywine Power Facility **Pollutant:** Nickel **Calendar Year :** 2017

Registration No./ Equip. Description	Actual Emissions [tons/year]	[lbs/day]	[lbs/hr]	Control Device	Efficiency [%]
5-0844 Unit 1/A GT	0.000011	0.00	0.0030	uncontrolled /fuel oil operation only	N/A
5-0845 Unit 2/B GT	0.000018	0.00	0.0028	uncontrolled /fuel oil operation only	N/A
Totals	0.000029	0.00	0.0057		

Note 1: Emissions must be broken down by equipment registration number.

Form 4:

TOXIC AIR POLLUTANTS

EMISSIONS CERTIFICATION REPORT

Facility name: Brandywine Power Fac **Pollutant:** Propylene oxide **Calendar Year :** 2017

Registration No./ Equip. Description	Actual Emissions [tons/year]	[lbs/day]	[lbs/hr]	Control Device	Efficiency [%]
5-0844 Unit 1/A GT	0.03797	0.40	0.023	uncontrolled /Gas operation only	N/A
5-0845 Unit 2/B GT	0.04454	0.38	0.022	uncontrolled /Gas operation only	N/A
Totals	0.08251	0.78	0.044		

Note 1: Emissions must be broken down by equipment registration number.

Form 4:

TOXIC AIR POLLUTANTS

EMISSIONS CERTIFICATION REPORT

Facility name: Brandywine Power Facility **Pollutant:** Selenium **Calendar Year :** 2017

Registration No./ Equip. Description	Actual Emissions [tons/year]	[lbs/day]	[lbs/hr]	Control Device	Efficiency [%]
5-0844 Unit 1/A GT	0.00006	0.00	0.016	uncontrolled /fuel oil operation only	N/A
5-0845 Unit 2/B GT	0.00010	0.00	0.015	uncontrolled /fuel oil operation only	N/A
Totals	0.00016	0.00	0.031		

Note 1: Emissions must be broken down by equipment registration number.

Form 6: Greenhouse Gases

GREENHOUSE GAS AIR POLLUTANTS

EMISSIONS CERTIFICATION REPORT

Facility name: Brandywine Power Facility **Pollutant:** Carbon Dioxide **Calendar Year :** 2017

Registration No./ Equip. Description	SCC Number	Actual Emissions (see Note 2)		
		[tons/year]	[lbs/day]	[lbs/hr]
5-0844 Unit 1/A GT	20100201	155,994	1,642,042.1	92,747.6
5-0845 Unit 2/B GT	20100201	183,196	1,559,114.9	88,527.4
9-1465 Unit 3/ Emerg Diesel	20100102	41	2,172	2,958
Totals		339,231	3,203,328.6	184,232.7

Note 1: Emissions must be broken down by equipment registration number.

Note 2: Combustion Turbine Emissions are as computed by the plant's Continuous Emission Monitoring System (CEMS) Data Acquisition & Handling System (using EPA formula G-4).

Actual CO2 emissions values were obtained from the EPA-ECMPS emissions reporting system.

Note 3: Emergency Diesel Engine Emissions are calculated based on Manufacturer's Performance Data

Form 6: Greenhouse Gases

GREENHOUSE GAS AIR POLLUTANTS

EMISSIONS CERTIFICATION REPORT

Facility name: Brandywine Power Facility **Pollutant:** Nitrous Oxide (N2O) **Calendar Year :** 2017

Registration No./ Equip. Description	SCC Number	Actual Emissions		
		[tons/year]	[lbs/day]	[lbs/hr]
5-0844 Unit 1/A GT	20100201	3.9	41.3	2.3
5-0845 Unit 2/B GT	20100201	4.6	39.2	2.2
9-1465 Unit 3/ Emerg Diesel	20100102	0.0003	0.02	0.02
Totals		8.5	80.6	4.6

Note 1: Emissions must be broken down by equipment registration number.

Form 6: Greenhouse Gases

GREENHOUSE GAS AIR POLLUTANTS

EMISSIONS CERTIFICATION REPORT

Facility name: Brandywine Power Facility **Pollutant:** Methane (CH_4) **Calendar Year :** 2017

Registration No./ Equip. Description	SCC Number	Actual Emissions		
		[tons/year]	[lbs/day]	[lbs/hr]
5-0844 Unit 1/A GT	20100201	11.3	118.5	6.7
5-0845 Unit 2/B GT	20100201	13.2	112.4	6.4
9-1465 Unit 3/ Emerg Diesel	20100102	0.0016	0.08	0.11
Totals		24.5	231.0	13.2

Note 1: Emissions must be broken down by equipment registration number.

3.1 Stationary Gas Turbines

3.1.1 General[1]

Gas turbines, also called "combustion turbines", are used in a broad scope of applications including electric power generation, cogeneration, natural gas transmission, and various process applications. Gas turbines are available with power outputs ranging in size from 300 horsepower (hp) to over 268,000 hp, with an average size of 40,200 hp.[2] The primary fuels used in gas turbines are natural gas and distillate (No. 2) fuel oil.[3]

3.1.2 Process Description[1,2]

A gas turbine is an internal combustion engine that operates with rotary rather than reciprocating motion. Gas turbines are essentially composed of three major components: compressor, combustor, and power turbine. In the compressor section, ambient air is drawn in and compressed up to 30 times ambient pressure and directed to the combustor section where fuel is introduced, ignited, and burned. Combustors can either be annular, can-annular, or silo. An annular combustor is a doughnut-shaped, single, continuous chamber that encircles the turbine in a plane perpendicular to the air flow. Can-annular combustors are similar to the annular; however, they incorporate several can-shaped combustion chambers rather than a single continuous chamber. Annular and can-annular combustors are based on aircraft turbine technology and are typically used for smaller scale applications. A silo (frame-type) combustor has one or more combustion chambers mounted external to the gas turbine body. Silo combustors are typically larger than annular or can-annular combustors and are used for larger scale applications.

The combustion process in a gas turbine can be classified as diffusion flame combustion, or lean-premix staged combustion. In the diffusion flame combustion, the fuel/air mixing and combustion take place simultaneously in the primary combustion zone. This generates regions of near-stoichiometric fuel/air mixtures where the temperatures are very high. For lean-premix combustors, fuel and air are thoroughly mixed in an initial stage resulting in a uniform, lean, unburned fuel/air mixture which is delivered to a secondary stage where the combustion reaction takes place. Manufacturers use different types of fuel/air staging, including fuel staging, air staging, or both; however, the same staged, lean-premix principle is applied. Gas turbines using staged combustion are also referred to as Dry Low NO_X combustors. The majority of gas turbines currently manufactured are lean-premix staged combustion turbines.

Hot gases from the combustion section are diluted with additional air from the compressor section and directed to the power turbine section at temperatures up to 2600°F. Energy from the hot exhaust gases, which expand in the power turbine section, are recovered in the form of shaft horsepower. More than 50 percent of the shaft horsepower is needed to drive the internal compressor and the balance of recovered shaft horsepower is available to drive an external load.[2] Gas turbines may have one, two, or three shafts to transmit power between the inlet air compression turbine, the power turbine, and the exhaust turbine. The heat content of the exhaust gases exiting the turbine can either be discarded without heat recovery (simple cycle); recovered with a heat exchanger to preheat combustion air entering the combustor (regenerative cycle); recovered in a heat recovery steam generator to raise process steam, with or without supplementary firing (cogeneration); or recovered, with or without supplementary firing, to raise steam for a steam turbine Rankine cycle (combined cycle or repowering).

The simple cycle is the most basic operating cycle of gas turbines with a thermal efficiency ranging from 15 to 42 percent. The cycle thermal efficiency is defined as the ratio of useful shaft energy to fuel energy input. Simple cycle gas turbines are typically used for shaft horsepower applications without recovery of exhaust heat. For example, simple cycle gas turbines are used by electric utilities for generation of electricity during emergencies or during peak demand periods.

A regenerative cycle is a simple cycle gas turbine with an added heat exchanger. The heat exchanger uses the turbine exhaust gases to heat the combustion air which reduces the amount of fuel required to reach combustor temperatures. The thermal efficiency of a regenerative cycle is approximately 35 percent. However, the amount of fuel efficiency and saving may not be sufficient to justify the capital cost of the heat exchanger, rendering the process unattractive.

A cogeneration cycle consists of a simple cycle gas turbine with a heat recovery steam generator (HRSG). The cycle thermal efficiency can be as high as 84 percent. In a cogeneration cycle, the steam generated by the HRSG can be delivered at a variety of pressures and temperatures to other thermal processes at the site. For situations where additional steam is required, a supplementary burner, or duct burner, can be placed in the exhaust duct stream of the HRSG to meet the site's steam requirements.

A combined cycle gas turbine is a gas turbine with a HRSG applied at electric utility sites. The gas turbine drives an electric generator, and the steam from the HRSG drives a steam turbine which also drives an electric generator. A supplementary-fired boiler can be used to increase the steam production. The thermal efficiency of a combined cycle gas turbine is between 38 percent and 60 percent.

Gas turbine applications include gas and oil industry, emergency power generation facilities, independent electric power producers (IPP), electric utilities, and other industrial applications. The petroleum industry typically uses simple cycle gas turbines with a size range from 300 hp to 20,000 hp. The gas turbine is used to provide shaft horsepower for oil and gas production and transmission. Emergency power generation sites also utilize simple cycle gas turbines. Here the gas turbine is used to provide backup or emergency power to critical networks or equipment. Usually, gas turbines under 5,000 hp are used at emergency power generation sites.

Independent electrical power producers generate electricity for resale to larger electric utilities. Simple, regenerative, or combined cycle gas turbines are used at IPP; however, most installations use combined cycle gas turbines. The gas turbines used at IPP can range from 1,000 hp to over 100,000 hp. The larger electric utilities use gas turbines mostly as peaking units for meeting power demand peaks imposed by large commercial and industrial users on a daily or seasonal basis. Simple cycle gas turbines ranging from 20,000 hp to over 200,000 hp are used at these installations. Other industrial applications for gas turbines include pulp and paper, chemical, and food processing. Here, combined cycle gas turbines are used for cogeneration.

3.1.3 Emissions

The primary pollutants from gas turbine engines are nitrogen oxides (NO_X), carbon monoxide (CO), and to a lesser extent, volatile organic compounds (VOC). Particulate matter (PM) is also a primary pollutant for gas turbines using liquid fuels. Nitrogen oxide formation is strongly dependent on the high temperatures developed in the combustor. Carbon monoxide, VOC, hazardous air pollutants (HAP), and PM are primarily the result of incomplete combustion. Trace to low amounts of HAP and sulfur dioxide (SO_2) are emitted from gas turbines. Ash and metallic additives in the fuel may also contribute to PM in the exhaust. Oxides of sulfur (SO_X) will only appear in a significant quantity if heavy oils are fired

in the turbine. Emissions of sulfur compounds, mainly SO_2, are directly related to the sulfur content of the fuel.

Available emissions data indicate that the turbine's operating load has a considerable effect on the resulting emission levels. Gas turbines are typically operated at high loads (greater than or equal to 80 percent of rated capacity) to achieve maximum thermal efficiency and peak combustor zone flame temperatures. With reduced loads (lower than 80 percent), or during periods of frequent load changes, the combustor zone flame temperatures are expected to be lower than the high load temperatures, yielding lower thermal efficiencies and more incomplete combustion. The emission factors for this sections are presented for gas turbines operating under high load conditions. Section 3.1 background information document and emissions database contain additional emissions data for gas turbines operating under various load conditions.

Gas turbines firing distillate oil may emit trace metals carried over from the metals content of the fuel. If the fuel analysis is known, the metals content of the fuel ash should be used for flue gas emission factors assuming all metals pass through the turbine.

If the HRSG is not supplementary fuel fired, the simple cycle input-specific emission factors (pounds per million British thermal units [lb/MMBtu]) will also apply to cogeneration/combined cycle systems. If the HRSG is supplementary fired, the emissions attributable to the supplementary firing must also be considered to estimate total stack emissions.

3.1.3.1 Nitrogen Oxides -

Nitrogen oxides formation occurs by three fundamentally different mechanisms. The principal mechanism with turbines firing gas or distillate fuel is thermal NO_X, which arises from the thermal dissociation and subsequent reaction of nitrogen (N_2) and oxygen (O_2) molecules in the combustion air. Most thermal NO_X is formed in high temperature stoichiometric flame pockets downstream of the fuel injectors where combustion air has mixed sufficiently with the fuel to produce the peak temperature fuel/air interface.

The second mechanism, called prompt NO_X, is formed from early reactions of nitrogen molecules in the combustion air and hydrocarbon radicals from the fuel. Prompt NO_X forms within the flame and is usually negligible when compared to the amount of thermal NO_X formed. The third mechanism, fuel NO_X, stems from the evolution and reaction of fuel-bound nitrogen compounds with oxygen. Natural gas has negligible chemically-bound fuel nitrogen (although some molecular nitrogen is present). Essentially all NO_X formed from natural gas combustion is thermal NO_X. Distillate oils have low levels of fuel-bound nitrogen. Fuel NO_X from distillate oil-fired turbines may become significant in turbines equipped with a high degree of thermal NO_X controls. Otherwise, thermal NO_X is the predominant NO_X formation mechanism in distillate oil-fired turbines.

The maximum thermal NO_X formation occurs at a slightly fuel-lean mixture because of excess oxygen available for reaction. The control of stoichiometry is critical in achieving reductions in thermal NO_X. Thermal NO_X formation also decreases rapidly as the temperature drops below the adiabatic flame temperature, for a given stoichiometry. Maximum reduction of thermal NO_X can be achieved by control of both the combustion temperature and the stoichiometry. Gas turbines operate with high overall levels of excess air, because turbines use combustion air dilution as the means to maintain the turbine inlet temperature below design limits. In older gas turbine models, where combustion is in the form of a diffusion flame, most of the dilution takes place downstream of the primary flame, which does not minimize peak temperature in the flame and suppress thermal NO_X formation.

Diffusion flames are characterized by regions of near-stoichiometric fuel/air mixtures where temperatures are very high and significant thermal NO_X is formed. Water vapor in the turbine inlet air contributes to the lowering of the peak temperature in the flame, and therefore to thermal NO_X emissions. Thermal NO_X can also be reduced in diffusion type turbines through water or steam injection. The injected water-steam acts as a heat sink lowering the combustion zone temperature, and therefore thermal NO_X. Newer model gas turbines use lean, premixed combustion where the fuel is typically premixed with more than 50 percent theoretical air which results in lower flame temperatures, thus suppressing thermal NO_X formation.

Ambient conditions also affect emissions and power output from turbines more than from external combustion systems. The operation at high excess air levels and at high pressures increases the influence of inlet humidity, temperature, and pressure.[4] Variations of emissions of 30 percent or greater have been exhibited with changes in ambient humidity and temperature. Humidity acts to absorb heat in the primary flame zone due to the conversion of the water content to steam. As heat energy is used for water to steam conversion, the temperature is the flame zone will decrease resulting in a decrease of thermal NO_X formation. For a given fuel firing rate, lower ambient temperatures lower the peak temperature in the flame, lowering thermal NO_X significantly. Similarly, the gas turbine operating loads affect NO_X emissions. Higher NO_X emissions are expected for high operating loads due to the higher peak temperature in the flame zone resulting in higher thermal NO_X.

3.1.3.2 Carbon Monoxide and Volatile Organic Compounds -

CO and VOC emissions both result from incomplete combustion. CO results when there is insufficient residence time at high temperature or incomplete mixing to complete the final step in fuel carbon oxidation. The oxidation of CO to CO_2 at gas turbine temperatures is a slow reaction compared to most hydrocarbon oxidation reactions. In gas turbines, failure to achieve CO burnout may result from quenching by dilution air. With liquid fuels, this can be aggravated by carryover of larger droplets from the atomizer at the fuel injector. Carbon monoxide emissions are also dependent on the loading of the gas turbine. For example, a gas turbine operating under a full load will experience greater fuel efficiencies which will reduce the formation of carbon monoxide. The opposite is also true, a gas turbine operating under a light to medium load will experience reduced fuel efficiencies (incomplete combustion) which will increase the formation of carbon monoxide.

The pollutants commonly classified as VOC can encompass a wide spectrum of volatile organic compounds some of which are hazardous air pollutants. These compounds are discharged into the atmosphere when some of the fuel remains unburned or is only partially burned during the combustion process. With natural gas, some organics are carried over as unreacted, trace constituents of the gas, while others may be pyrolysis products of the heavier hydrocarbon constituents. With liquid fuels, large droplet carryover to the quench zone accounts for much of the unreacted and partially pyrolized volatile organic emissions.

Similar to CO emissions, VOC emissions are affected by the gas turbine operating load conditions. Volatile organic compounds emissions are higher for gas turbines operating at low loads as compared to similar gas turbines operating at higher loads.

3.1.3.3 Particulate Matter[13] -

PM emissions from turbines primarily result from carryover of noncombustible trace constituents in the fuel. PM emissions are negligible with natural gas firing and marginally significant with distillate oil firing because of the low ash content. PM emissions can be classified as "filterable" or "condensable" PM. Filterable PM is that portion of the total PM that exists in the stack in either the solid or liquid state and

can be measured on a EPA Method 5 filter. Condensable PM is that portion of the total PM that exists as a gas in the stack but condenses in the cooler ambient air to form particulate matter. Condensable PM exists as a gas in the stack, so it passes through the Method 5 filter and is typically measured by analyzing the impingers, or "back half" of the sampling train. The collection, recovery, and analysis of the impingers is described in EPA Method 202 of Appendix M, Part 51 of the Code of Federal Regulations. Condensable PM is composed of organic and inorganic compounds and is generally considered to be all less than 1.0 micrometers in aerodynamic diameter.

3.1.3.4 Greenhouse Gases[5-11] -

Carbon dioxide (CO_2) and nitrous oxide (N_2O) emissions are all produced during natural gas and distillate oil combustion in gas turbines. Nearly all of the fuel carbon is converted to CO_2 during the combustion process. This conversion is relatively independent of firing configuration. Methane (CH_4) is also present in the exhaust gas and is thought to be unburned fuel in the case of natural gas or a product of combustion in the case of distillate fuel oil.

Although the formation of CO acts to reduce CO_2 emissions, the amount of CO produced is insignificant compared to the amount of CO_2 produced. The majority of the fuel carbon not converted to CO_2 is due to incomplete combustion.

Formation of N_2O during the combustion process is governed by a complex series of reactions and its formation is dependent upon many factors. However, the formation of N_2O is minimized when combustion temperatures are kept high (above 1475°F) and excess air is kept to a minimum (less than 1 percent).

3.1.3.5 HAP Emissions -

Available data indicate that emission levels of HAP are lower for gas turbines than for other combustion sources. This is due to the high combustion temperatures reached during normal operation. The emissions data also indicate that formaldehyde is the most significant HAP emitted from combustion turbines. For natural gas fired turbines, formaldehyde accounts for about two-thirds of the total HAP emissions. Polycyclic aromatic hydrocarbons (PAH), benzene, toluene, xylenes, and others account for the remaining one-third of HAP emissions. For No. 2 distillate oil-fired turbines, small amount of metallic HAP are present in the turbine's exhaust in addition to the gaseous HAP identified under gas fired turbines. These metallic HAP are carried over from the fuel constituents. The formation of carbon monoxide during the combustion process is a good indication of the expected levels of HAP emissions. Similar to CO emissions, HAP emissions increase with reduced operating loads. Typically, combustion turbines operate under full loads for greater fuel efficiency, thereby minimizing the amount of CO and HAP emissions.

3.1.4 Control Technologies[12]

There are three generic types of emission controls in use for gas turbines, wet controls using steam or water injection to reduce combustion temperatures for NO_X control, dry controls using advanced combustor design to suppress NO_X formation and/or promote CO burnout, and post-combustion catalytic control to selectively reduce NO_X and/or oxidize CO emission from the turbine. Other recently developed technologies promise significantly lower levels of NO_X and CO emissions from diffusion combustion type gas turbines. These technologies are currently being demonstrated in several installations.

Emission factors in this section have been determined from gas turbines with no add-on control devices (uncontrolled emissions). For NO_X and CO emission factors for combustion controls, such as water-steam injection, and lean pre-mix units are presented. Additional information for controlled

emissions with various add-on controls can be obtained using the section 3.1 database. Uncontrolled, lean-premix, and water injection emission factors were presented for NO_X and CO to show the effect of combustion modification on emissions.

3.1.4.1 Water Injection -

Water or steam injection is a technology that has been demonstrated to effectively suppress NO_X emissions from gas turbines. The effect of steam and water injection is to increase the thermal mass by dilution and thereby reduce peak temperatures in the flame zone. With water injection, there is an additional benefit of absorbing the latent heat of vaporization from the flame zone. Water or steam is typically injected at a water-to-fuel weight ratio of less than one.

Depending on the initial NO_X levels, such rates of injection may reduce NO_X by 60 percent or higher. Water or steam injection is usually accompanied by an efficiency penalty (typically 2 to 3 percent) but an increase in power output (typically 5 to 6 percent). The increased power output results from the increased mass flow required to maintain turbine inlet temperature at manufacturer's specifications. Both CO and VOC emissions are increased by water injection, with the level of CO and VOC increases dependent on the amount of water injection.

3.1.4.2 Dry Controls -

Since thermal NO_X is a function of both temperature (exponentially) and time (linearly), the basis of dry controls are to either lower the combustor temperature using lean mixtures of air and/or fuel staging, or decrease the residence time of the combustor. A combination of methods may be used to reduce NO_X emissions such as lean combustion and staged combustion (two stage lean/lean combustion or two stage rich/lean combustion).

Lean combustion involves increasing the air-to-fuel ratio of the mixture so that the peak and average temperatures within the combustor will be less than that of the stoichiometric mixture, thus suppressing thermal NO_X formation. Introducing excess air not only creates a leaner mixture but it also can reduce residence time at peak temperatures.

Two-stage lean/lean combustors are essentially fuel-staged, premixed combustors in which each stage burns lean. The two-stage lean/lean combustor allows the turbine to operate with an extremely lean mixture while ensuring a stable flame. A small stoichiometric pilot flame ignites the premixed gas and provides flame stability. The NO_X emissions associated with the high temperature pilot flame are insignificant. Low NO_X emission levels are achieved by this combustor design through cooler flame temperatures associated with lean combustion and avoidance of localized "hot spots" by premixing the fuel and air.

Two stage rich/lean combustors are essentially air-staged, premixed combustors in which the primary zone is operated fuel rich and the secondary zone is operated fuel lean. The rich mixture produces lower temperatures (compared to stoichiometric) and higher concentrations of CO and H_2, because of incomplete combustion. The rich mixture also decreases the amount of oxygen available for NO_X generation. Before entering the secondary zone, the exhaust of the primary zone is quenched (to extinguish the flame) by large amounts of air and a lean mixture is created. The lean mixture is pre-ignited and the combustion completed in the secondary zone. NO_X formation in the second stage are minimized through combustion in a fuel lean, lower temperature environment. Staged combustion is identified through a variety of names, including Dry-Low NOx (DLN), Dry-Low Emissions (DLE), or SoLoNOx.

3.1.4.3 Catalytic Reduction Systems -

Selective catalytic reduction (SCR) systems selectively reduce NO_X emissions by injecting ammonium (NH_3) into the exhaust gas stream upstream of a catalyst. Nitrogen oxides, NH_3, and O_2 react on the surface of the catalyst to form N_2 and H_2O. The exhaust gas must contain a minimum amount of O_2 and be within a particular temperature range (typically 450°F to 850°F) in order for the SCR system to operate properly.

The temperature range is dictated by the catalyst material which is typically made from noble metals, including base metal oxides such as vanadium and titanium, or zeolite-based material. The removal efficiency of an SCR system in good working order is typically from 65 to 90 percent. Exhaust gas temperatures greater than the upper limit (850°F) cause NO_X and NH_3 to pass through the catalyst unreacted. Ammonia emissions, called NH_3 slip, may be a consideration when specifying an SCR system.

Ammonia, either in the form of liquid anhydrous ammonia, or aqueous ammonia hydroxide is stored on site and injected into the exhaust stream upstream of the catalyst. Although an SCR system can operate alone, it is typically used in conjunction with water-steam injection systems or lean-premix system to reduce NO_X emissions to their lowest levels (less than 10 ppm at 15 percent oxygen for SCR and wet injection systems). The SCR system for landfill or digester gas-fired turbines requires a substantial fuel gas pretreatment to remove trace contaminants that can poison the catalyst. Therefore, SCR and other catalytic treatments may be inappropriate control technologies for landfill or digester gas-fired turbines.

The catalyst and catalyst housing used in SCR systems tend to be very large and dense (in terms of surface area to volume ratio) because of the high exhaust flow rates and long residence times required for NO_X, O_2, and NH_3, to react on the catalyst. Most catalysts are configured in a parallel-plate, "honeycomb" design to maximize the surface area-to-volume ratio of the catalyst. Some SCR installations incorporate CO catalytic oxidation modules along with the NO_X reduction catalyst for simultaneous CO/NO_X control.

Carbon monoxide oxidation catalysts are typically used on turbines to achieve control of CO emissions, especially turbines that use steam injection, which can increase the concentrations of CO and unburned hydrocarbons in the exhaust. CO catalysts are also being used to reduce VOC and organic HAPs emissions. The catalyst is usually made of a precious metal such as platinum, palladium, or rhodium. Other formulations, such as metal oxides for emission streams containing chlorinated compounds, are also used. The CO catalyst promotes the oxidation of CO and hydrocarbon compounds to carbon dioxide (CO_2) and water (H_2O) as the emission stream passes through the catalyst bed. The oxidation process takes place spontaneously, without the requirement for introducing reactants. The performance of these oxidation catalyst systems on combustion turbines results in 90-plus percent control of CO and about 85 to 90 percent control of formaldehyde. Similar emission reductions are expected on other HAP pollutants.

3.1.4.4 Other Catalytic Systems[14,15] -

New catalytic reduction technologies have been developed and are currently being commercially demonstrated for gas turbines. Such technologies include, but are not limited to, the SCONOX and the XONON systems, both of which are designed to reduce NO_X and CO emissions. The SCONOX system is applicable to natural gas fired gas turbines. It is based on a unique integration of catalytic oxidation and absorption technology. CO and NO are catalytically oxidized to CO_2 and NO_2. The NO_2 molecules are subsequently absorbed on the treated surface of the SCONOX catalyst. The system manufacturer guarantees CO emissions of 1 ppm and NO_X emissions of 2 ppm. The SCONOX system does not require the use of ammonia, eliminating the potential of ammonia slip conditions evident in existing SCR systems. Only limited emissions data were available for a gas turbine equipped with a SCONOX system. This data reflected HAP emissions and was not sufficient to verify the manufacturer's claims.

The XONON system is applicable to diffusion and lean-premix combustors and is currently being demonstrated with the assistance of leading gas turbine manufacturers. The system utilizes a flameless combustion system where fuel and air reacts on a catalyst surface, preventing the formation of NO_X while achieving low CO and unburned hydrocarbon emission levels. The overall combustion process consists of the partial combustion of the fuel in the catalyst module followed by completion of the combustion downstream of the catalyst. The partial combustion within the catalyst produces no NO_X, and the combustion downstream of the catalyst occurs in a flameless homogeneous reaction that produces almost no NO_X. The system is totally contained within the combustor of the gas turbine and is not a process for clean-up of the turbine exhaust. Note that this technology has not been fully demonstrated as of the drafting of this section. The catalyst manufacturer claims that gas turbines equipped with the XONON Catalyst emit NO_X levels below 3 ppm and CO and unburned hydrocarbons levels below 10 ppm. Emissions data from gas turbines equipped with a XONON Catalyst were not available as of the drafting of this section.

3.1.5 Updates Since the Fifth Edition

The Fifth Edition was released in January 1995. Revisions to this section since that date are summarized below. For further detail, consult the memoranda describing each supplement or the background report for this section. These and other documents can be found on the new EFIG home page (http://www.epa.gov/ttn/chief).

Supplement A, February 1996

- For the PM factors, a footnote was added to clarify that condensables and all PM from oil- and gas-fired turbines are considered PM-10.
- In the table for large uncontrolled gas turbines, a sentence was added to footnote "e" to indicate that when sulfur content is not available, 0.6 lb/10^6 ft^3 (0.0006 lb/MMBtu) can be used.

Supplement B, October 1996

- Text was revised and updated for the general section.
- Text was added regarding firing practices and process description.
- Text was revised and updated for emissions and controls.
- All factors for turbines with SCR-water injection control were corrected.
- The CO_2 factor was revised and a new set of N_2O factors were added.

Supplement F, April 2000

- Text was revised and updated for the general section.
- All emission factors were updated except for the SO_2 factor for natural gas and distillate oil turbines.

- Turbines using staged (lean-premix) combustors added to this section.
- Turbines used for natural gas transmission added to this section.
- Details for turbine operating configurations (operating cycles) added to this section.
- Information on new emissions control technologies added to this section (SCONOX and XONON).
- HAP emission factors added to this section based on over 400 data points taken from over 60 source tests.
- PM condensable and filterable emission factors for natural gas and distillate oil fired turbines were developed.
- NOx and CO emission factors for lean-premix turbines were added.
- Emission factors for landfill gas and digester gas were added.

Table 3.1-1. EMISSION FACTORS FOR NITROGEN OXIDES (NO_X) AND CARBON MONOXIDE (CO) FROM STATIONARY GAS TURBINES

Emission Factors[a]				
Turbine Type	Nitrogen Oxides		Carbon Monoxide	
Natural Gas-Fired Turbines[b]	(lb/MMBtu)[c] (Fuel Input)	Emission Factor Rating	(lb/MMBtu)[c] (Fuel Input)	Emission Factor Rating
Uncontrolled	3.2 E-01	A	8.2 E-02[d]	A
Water-Steam Injection	1.3 E-01	A	3.0 E-02	A
Lean-Premix	9.9 E-02	D	1.5 E-02	D
Distillate Oil-Fired Turbines[e]	(lb/MMBtu)[f] (Fuel Input)	Emission Factor Rating	(lb/MMBtu)[f] (Fuel Input)	Emission Factor Rating
Uncontrolled	8.8 E-01	C	3.3 E-03	C
Water-Steam Injection	2.4 E-01	B	7.6 E-02	C
Landfill Gas-Fired Turbines[g]	(lb/MMBtu)[h] (Fuel Input)	Emission Factor Rating	(lb/MMBtu)[h] (Fuel Input)	Emission Factor Rating
Uncontrolled	1.4 E-01	A	4.4 E-01	A
Digester Gas-Fired Turbines[j]	(lb/MMBtu)[k] (Fuel Input)	Emission Factor Rating	(lb/MMBtu)[k] (Fuel Input)	Emission Factor Rating
Uncontrolled	1.6 E-01	D	1.7 E-02	D

[a] Factors are derived from units operating at high loads (≥80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief".

[b] Source Classification Codes (SCCs) for natural gas-fired turbines include 2-01-002-01, 2-02-002-01, 2-02-002-03, 2-03-002-02, and 2-03-002-03. The emission factors in this table may be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this average heating value.

[c] Emission factors based on an average natural gas heating value (HHV) of 1020 Btu/scf at 60°F. To convert from (lb/MMBtu) to ($lb/10^6$ scf), multiply by 1020.

[d] It is recognized that the uncontrolled emission factor for CO is higher than the water-steam injection and lean-premix emission factors, which is contrary to expectation. The EPA could not identify the reason for this behavior, except that the data sets used for developing these factors are different.

[e] SCCs for distillate oil-fired turbines include 2-01-001-01, 2-02-001-01, 2-02-001-03, and 2-03-001-02.

[f] Emission factors based on an average distillate oil heating value of 139 MMBtu/10^3 gallons. To convert from (lb/MMBtu) to ($lb/10^3$ gallons), multiply by 139.

[g] SCC for landfill gas-fired turbines is 2-03-008-01.

[h] Emission factors based on an average landfill gas heating value of 400 Btu/scf at 60°F. To convert from (lb/MMBtu), to ($lb/10^6$ scf) multiply by 400.

[j] SCC for digester gas-fired turbine is 2-03-007-01.

[k] Emission factors based on an average digester gas heating value of 600 Btu/scf at 60°F. To convert from (lb/MMBtu) to ($lb/10^6$ scf) multiply by 600.

Table 3.1-2a. EMISSION FACTORS FOR CRITERIA POLLUTANTS AND GREENHOUSE GASES FROM STATIONARY GAS TURBINES

Pollutant	Emission Factors[a] - Uncontrolled			
	Natural Gas-Fired Turbines[b]		Distillate Oil-Fired Turbines[d]	
	(lb/MMBtu)[c] (Fuel Input)	Emission Factor Rating	(lb/MMBtu)[e] (Fuel Input)	Emission Factor Rating
CO_2[f]	110	A	157	A
N_2O	0.003[g]	E	ND	NA
Lead	ND	NA	1.4 E-05	C
SO_2	0.94S[h]	B	1.01S[h]	B
Methane	8.6 E-03	C	ND	NA
VOC	2.1 E-03	D	4.1 E-04[j]	E
TOC[k]	1.1 E-02	B	4.0 E-03[l]	C
PM (condensible)	4.7 E-03[l]	C	7.2 E-03[l]	C
PM (filterable)	1.9 E-03[l]	C	4.3 E-03[l]	C
PM (total)	6.6 E-03[l]	C	1.2 E-02[l]	C

[a] Factors are derived from units operating at high loads (≥80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief". ND = No Data, NA = Not Applicable.

[b] SCCs for natural gas-fired turbines include 2-01-002-01, 2-02-002-01 & 03, and 2-03-002-02 & 03.

[c] Emission factors based on an average natural gas heating value (HHV) of 1020 Btu/scf at 60°F. To convert from (lb/MMBtu) to (lb/10^6 scf), multiply by 1020. Similarly, these emission factors can be converted to other natural gas heating values.

[d] SCCs for distillate oil-fired turbines are 2-01-001-01, 2-02-001-01, 2-02-001-03, and 2-03-001-02.

[e] Emission factors based on an average distillate oil heating value of 139 MMBtu/10^3 gallons. To convert from (lb/MMBtu) to (lb/10^3 gallons), multiply by 139.

[f] Based on 99.5% conversion of fuel carbon to CO_2 for natural gas and 99% conversion of fuel carbon to CO_2 for distillate oil. CO_2 (Natural Gas) [lb/MMBtu] = (0.0036 scf/Btu)(%CON)(C)(D), where %CON = weight percent conversion of fuel carbon to CO_2, C = carbon content of fuel by weight, and D = density of fuel. For natural gas, C is assumed at 75%, and D is assumed at 4.1 E+04 lb/10^6scf. For distillate oil, CO_2 (Distillate Oil) [lb/MMBtu] = (26.4 gal/MMBtu) (%CON)(C)(D), where C is assumed at 87%, and the D is assumed at 6.9 lb/gallon.

[g] Emission factor is carried over from the previous revision to AP-42 (Supplement B, October 1996) and is based on limited source tests on a single turbine with water-steam injection (Reference 5).

[h] All sulfur in the fuel is assumed to be converted to SO_2. S = percent sulfur in fuel. Example, if sulfur content in the fuel is 3.4 percent, then S = 3.4. If S is not available, use 3.4 E-03 lb/MMBtu for natural gas turbines, and 3.3 E-02 lb/MMBtu for distillate oil turbines (the equations are more accurate).

[j] VOC emissions are assumed equal to the sum of organic emissions.

[k] Pollutant referenced as THC in the gathered emission tests. It is assumed as TOC, because it is based on EPA Test Method 25A.

[l] Emission factors are based on combustion turbines using water-steam injection.

Table 3.1-2b. EMISSION FACTORS FOR CRITERIA POLLUTANTS AND GREENHOUSE GASES FROM STATIONARY GAS TURBINES

Emission Factors[a] - Uncontrolled				
Pollutants	Landfill Gas-Fired Turbines[b]		Digester Gas-Fired Turbines[d]	
	(lb/MMBtu)[c]	Emission Factor Rating	(lb/MMBtu)[c]	Emission Factor Rating
CO_2[f]	50	D	27	C
Lead	ND	NA	< 3.4 E-06[g]	D
PM-10	2.3 E-02	B	1.2 E-02	C
SO_2	4.5 E-02	C	6.5 E-03	D
VOC[h]	1.3 E-02	B	5.8 E-03	D

[a] Factors are derived from units operating at high loads (≥80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief". ND = No Data, NA = Not Applicable.

[b] SCC for landfill gas-fired turbines is 2-03-008-01.

[c] Emission factors based on an average landfill gas heating value (HHV) of 400 Btu/scf at 60°F. To convert from (lb/MMBtu) to (lb/10^6 scf), multiply by 400.

[d] SCC for digester gas-fired turbine include 2-03-007-01.

[e] Emission factors based on an average digester gas heating value of 600 Btu/scf at 60°F. To convert from (lb/MMBtu) to (lb/10^6 scf), multiply by 600.

[f] For landfill gas and digester gas, CO_2 is presented in test data as volume percent of the exhaust stream (4.0 percent to 4.5 percent).

[g] Compound was not detected. The presented emission value is based on one-half of the detection limit.

[h] Based on adding the formaldehyde emissions to the NMHC.

Table 3.1-3. EMISSION FACTORS FOR HAZARDOUS AIR POLLUTANTS FROM NATURAL GAS-FIRED STATIONARY GAS TURBINES[a]

Emission Factors[b] - Uncontrolled		
Pollutant	Emission Factor (lb/MMBtu)[c]	Emission Factor Rating
1,3-Butadiene[d]	< 4.3 E-07	D
Acetaldehyde	4.0 E-05	C
Acrolein	6.4 E-06	C
Benzene[e]	1.2 E-05	A
Ethylbenzene	3.2 E-05	C
Formaldehyde[f]	7.1 E-04	A
Naphthalene	1.3 E-06	C
PAH	2.2 E-06	C
Propylene Oxide[d]	< 2.9 E-05	D
Toluene	1.3 E-04	C
Xylenes	6.4 E-05	C

[a] SCC for natural gas-fired turbines include 2-01-002-01, 2-02-002-01, 2-02-002-03, 2-03-002-02, and 2-03-002-03. Hazardous Air Pollutants as defined in Section 112 (b) of the *Clean Air Act*.

[b] Factors are derived from units operating at high loads (≥80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief".

[c] Emission factors based on an average natural gas heating value (HHV) of 1020 Btu/scf at 60°F. To convert from (lb/MMBtu) to (lb/10^6 scf), multiply by 1020. These emission factors can be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this heating value.

[d] Compound was not detected. The presented emission value is based on one-half of the detection limit.

[e] Benzene with SCONOX catalyst is 9.1 E-07, rating of D.

[f] Formaldehyde with SCONOX catalyst is 2.0 E-05, rating of D.

Table 3.1-4. EMISSION FACTORS FOR HAZARDOUS AIR POLLUTANTS FROM DISTILLATE OIL-FIRED STATIONARY GAS TURBINES[a]

Emission Factors[b] - Uncontrolled		
Pollutant	Emission Factor (lb/MMBtu)[c]	Emission Factor Rating
1,3-Butadiene[d]	< 1.6 E-05	D
Benzene	5.5 E-05	C
Formaldehyde	2.8 E-04	B
Naphthalene	3.5 E-05	C
PAH	4.0 E-05	C

[a] SCCs for distillate oil-fired turbines include 2-01-001-01, 2-02-001-01, 2-02-001-03, and 2-03-001-02. Hazardous Air Pollutants as defined in Section 112 (b) of the *Clean Air Act*.

[b] Factors are derived from units operating at high loads (≥80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief".

[c] Emission factors based on an average distillate oil heating value (HHV) of 139 MMBtu/10^3 gallons. To convert from (lb/MMBtu) to (lb/10^3 gallons), multiply by 139.

[d] Compound was not detected. The presented emission value is based on one-half of the detection limit.

Table 3.1-5. EMISSION FACTORS FOR METALLIC HAZARDOUS AIR POLLUTANTS FROM DISTILLATE OIL-FIRED STATIONARY GAS TURBINES[a]

Emission Factors[b] - Uncontrolled		
Pollutant	Emission Factor (lb/MMBtu)[c]	Emission Factor Rating
Arsenic[d]	< 1.1 E-05	D
Beryllium[d]	< 3.1 E-07	D
Cadmium	4.8 E-06	D
Chromium	1.1 E-05	D
Lead	1.4 E-05	D
Manganese	7.9 E-04	D
Mercury	1.2 E-06	D
Nickel[d]	< 4.6 E-06	D
Selenium[d]	< 2.5 E-05	D

[a] SCCs for distillate oil-fired turbines include 2-01-001-01, 2-02-001-01, 2-02-001-03, and 2-03-001-02. Hazardous Air Pollutants as defined in Section 112 (b) of the *Clean Air Act*.

[b] Factors are derived from units operating at high loads (≥80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief".

[c] Emission factors based on an average distillate oil heating value (HHV) of 139 MMBtu/10^3 gallons. To convert from (lb/MMBtu) to (lb/10^3 gallons), multiply by 139.

[d] Compound was not detected. The presented emission value is based on one-half of the detection limit.

Table 3.1-6. EMISSION FACTORS FOR HAZARDOUS AIR POLLUTANTS FROM LANDFILL GAS-FIRED STATIONARY GAS TURBINES[a]

Emission Factors[b] - Uncontrolled		
Pollutant	Emission Factor (lb/MMBtu)[c]	Emission Factor Rating
Acetonitrile[d]	< 1.2E-05	D
Benzene	2.1E-05	B
Benzyl Chloride[d]	< 1.2 E-05	D
Carbon Tetrachloride[d]	< 1.8 E-06	D
Chlorobenzene[d]	< 2.9 E-06	D
Chloroform[d]	< 1.4 E-06	D
Methylene Chloride	2.3 E-06	D
Tetrachloroethylene[d]	< 2.5 E-06	D
Toluene	1.1 E-04	B
Trichloroethylene[d]	< 1.9 E-06	D
Vinyl Chloride[d]	< 1.6 E-06	D
Xylenes	3.1 E-05	B

[a] SCC for landfill gas-fired turbines is 2-03-008-01. Hazardous Air Pollutants as defined in Section 112 (b) of the *Clean Air Act*.

[b] Factors are derived from units operating at high loads (≥80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief".

[c] Emission factors based on an average landfill gas heating value (HHV) of 400 Btu/scf at 60°F. To convert from (lb/MMBtu) to (lb/10^6 scf), multiply by 400.

[d] Compound was not detected. The presented emission value is based on one-half of the detection limit.

Table 3.1-7. EMISSION FACTORS FOR HAZARDOUS AIR POLLUTANTS FROM DIGESTER GAS-FIRED STATIONARY GAS TURBINES[a]

Emission Factors[b] - Uncontrolled		
Pollutant	Emission Factor (lb/MMBtu)[c]	Emission Factor Ratings
1,3-Butadiene[d]	< 9.8 E-06	D
1,4-Dichlorobenzene[d]	< 2.0 E-05	D
Acetaldehyde	5.3 E-05	D
Carbon Tetrachloride[d]	< 2.0 E-05	D
Chlorobenzene[d]	< 1.6 E-05	D
Chloroform[d]	< 1.7 E-05	D
Ethylene Dichloride[d]	< 1.5 E-05	D
Formaldehyde	1.9 E-04	D
Methylene Chloride[d]	< 1.3 E-05	D
Tetrachloroethylene[d]	< 2.1 E-05	D
Trichloroethylene[d]	< 1.8 E-05	D
Vinyl Chloride[d]	< 3.6 E-05	D
Vinylidene Chloride[d]	< 1.5 E-05	D

[a] SCC for digester gas-fired turbines is 2-03-007-01. Hazardous Air Pollutants as defined in Section 112 (b) of the *Clean Air Act*.

[b] Factors are derived from units operating at high loads (≥80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief".

[c] Emission factors based on an average digester gas heating value (HHV) of 600 Btu/scf at 60°F. To convert from (lb/MMBtu) to (lb/10^6 scf), multiply by 600.

[d] Compound was not detected. The presented emission value is based on one-half of the detection limit.

Table 3.1-8. EMISSION FACTORS FOR METALLIC HAZARDOUS AIR POLLUTANTS FROM DIGESTER GAS-FIRED STATIONARY GAS TURBINES[a]

Emission Factors[b] - Uncontrolled		
Pollutant	Emission Factor (lb/MMBtu)[c]	Emission Factor Rating
Arsenic[d]	< 2.3 E-06	D
Cadmium[d]	< 5.8 E-07	D
Chromium[d]	< 1.2 E-06	D
Lead[d]	< 3.4 E-06	D
Nickel	2.0 E-06	D
Selenium	1.1 E-05	D

[a] SCC for digester gas-fired turbines is 2-03-007-01. Hazardous Air Pollutants as defined in Section 112 (b) of the *Clean Air Act*.

[b] Factors are derived from units operating at high loads (≥80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief".

[c] Emission factor based on an average digester gas heating value (HHV) of 600 Btu/scf at 60°F. To convert from (lb/MMBtu) to ($lb/10^6$ scf), multiply by 600.

[d] Compound was not detected. The presented emission value is based on one-half of the detection limit.

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3.4 Large Stationary Diesel And All Stationary Dual-fuel Engines

3.4.1 General

The primary domestic use of large stationary diesel engines (greater than 600 horsepower [hp]) is in oil and gas exploration and production. These engines, in groups of 3 to 5, supply mechanical power to operate drilling (rotary table), mud pumping, and hoisting equipment, and may also operate pumps or auxiliary power generators. Another frequent application of large stationary diesels is electricity generation for both base and standby service. Smaller uses include irrigation, hoisting, and nuclear power plant emergency cooling water pump operation.

Dual-fuel engines were developed to obtain compression ignition performance and the economy of natural gas, using a minimum of 5 to 6 percent diesel fuel to ignite the natural gas. Large dual-fuel engines have been used almost exclusively for prime electric power generation. This section includes all dual-fuel engines.

3.4.2 Process Description

All reciprocating internal combustion (IC) engines operate by the same basic process. A combustible mixture is first compressed in a small volume between the head of a piston and its surrounding cylinder. The mixture is then ignited, and the resulting high-pressure products of combustion push the piston through the cylinder. This movement is converted from linear to rotary motion by a crankshaft. The piston returns, pushing out exhaust gases, and the cycle is repeated.

There are 2 ignition methods used in stationary reciprocating IC engines, compression ignition (CI) and spark ignition (SI). In CI engines, combustion air is first compression heated in the cylinder, and diesel fuel oil is then injected into the hot air. Ignition is spontaneous because the air temperature is above the autoignition temperature of the fuel. SI engines initiate combustion by the spark of an electrical discharge. Usually the fuel is mixed with the air in a carburetor (for gasoline) or at the intake valve (for natural gas), but occasionally the fuel is injected into the compressed air in the cylinder. Although all diesel- fueled engines are compression ignited and all gasoline- and gas-fueled engines are spark ignited, gas can be used in a CI engine if a small amount of diesel fuel is injected into the compressed gas/air mixture to burn any mixture ratio of gas and diesel oil (hence the name dual fuel), from 6 to 100 percent diesel oil.

CI engines usually operate at a higher compression ratio (ratio of cylinder volume when the piston is at the bottom of its stroke to the volume when it is at the top) than SI engines because fuel is not present during compression; hence there is no danger of premature autoignition. Since engine thermal efficiency rises with increasing pressure ratio (and pressure ratio varies directly with compression ratio), CI engines are more efficient than SI engines. This increased efficiency is gained at the expense of poorer response to load changes and a heavier structure to withstand the higher pressures.[1]

3.4.3 Emissions And Controls

Most of the pollutants from IC engines are emitted through the exhaust. However, some total organic compounds (TOC) escape from the crankcase as a result of blowby (gases that are vented from the oil pan after they have escaped from the cylinder past the piston rings) and from the fuel tank

and carburetor because of evaporation. Nearly all of the TOCs from diesel CI engines enter the atmosphere from the exhaust. Crankcase blowby is minor because TOCs are not present during compression of the charge. Evaporative losses are insignificant in diesel engines due to the low volatility of diesel fuels. In general, evaporative losses are also negligible in engines using gaseous fuels because these engines receive their fuel continuously from a pipe rather than via a fuel storage tank and fuel pump.

The primary pollutants from internal combustion engines are oxides of nitrogen (NO_x), hydrocarbons and other organic compounds, carbon monoxide (CO), and particulates, which include both visible (smoke) and nonvisible emissions. Nitrogen oxide formation is directly related to high pressures and temperatures during the combustion process and to the nitrogen content, if any, of the fuel. The other pollutants, HC, CO, and smoke, are primarily the result of incomplete combustion. Ash and metallic additives in the fuel also contribute to the particulate content of the exhaust. Sulfur oxides also appear in the exhaust from IC engines. The sulfur compounds, mainly sulfur dioxide (SO_2), are directly related to the sulfur content of the fuel.[2]

3.4.3.1 Nitrogen Oxides -

Nitrogen oxide formation occurs by two fundamentally different mechanisms. The predominant mechanism with internal combustion engines is thermal NO_x which arises from the thermal dissociation and subsequent reaction of nitrogen (N_2) and oxygen (O_2) molecules in the combustion air. Most thermal NO_x is formed in the high-temperature region of the flame from dissociated molecular nitrogen in the combustion air. Some NO_x, called prompt NO_x, is formed in the early part of the flame from reaction of nitrogen intermediary species, and HC radicals in the flame. The second mechanism, fuel NO_x, stems from the evolution and reaction of fuel-bound nitrogen compounds with oxygen. Gasoline, and most distillate oils, have no chemically-bound fuel N_2 and essentially all NO_x formed is thermal NO_x.

3.4.3.2 Total Organic Compounds -

The pollutants commonly classified as hydrocarbons are composed of a wide variety of organic compounds and are discharged into the atmosphere when some of the fuel remains unburned or is only partially burned during the combustion process. Most unburned hydrocarbon emissions result from fuel droplets that were transported or injected into the quench layer during combustion. This is the region immediately adjacent to the combustion chamber surfaces, where heat transfer outward through the cylinder walls causes the mixture temperatures to be too low to support combustion.

Partially burned hydrocarbons can occur because of poor air and fuel homogeneity due to incomplete mixing, before or during combustion; incorrect air/fuel ratios in the cylinder during combustion due to maladjustment of the engine fuel system; excessively large fuel droplets (diesel engines); and low cylinder temperature due to excessive cooling (quenching) through the walls or early cooling of the gases by expansion of the combustion volume caused by piston motion before combustion is completed.[2]

3.4.3.3 Carbon Monoxide -

Carbon monoxide is a colorless, odorless, relatively inert gas formed as an intermediate combustion product that appears in the exhaust when the reaction of CO to CO_2 cannot proceed to completion. This situation occurs if there is a lack of available oxygen near the hydrocarbon (fuel) molecule during combustion, if the gas temperature is too low, or if the residence time in the cylinder is too short. The oxidation rate of CO is limited by reaction kinetics and, as a consequence, can be accelerated only to a certain extent by improvements in air and fuel mixing during the combustion process.[2-3]

3.4.3.4 Smoke, Particulate Matter, and PM-10 -

White, blue, and black smoke may be emitted from IC engines. Liquid particulates appear as white smoke in the exhaust during an engine cold start, idling, or low load operation. These are formed in the quench layer adjacent to the cylinder walls, where the temperature is not high enough to ignite the fuel. Blue smoke is emitted when lubricating oil leaks, often past worn piston rings, into the combustion chamber and is partially burned. Proper maintenance is the most effective method of preventing blue smoke emissions from all types of IC engines. The primary constituent of black smoke is agglomerated carbon particles (soot).[2]

3.4.3.5 Sulfur Oxides -

Sulfur oxide emissions are a function of only the sulfur content in the fuel rather than any combustion variables. In fact, during the combustion process, essentially all the sulfur in the fuel is oxidized to SO_2. The oxidation of SO_2 gives sulfur trioxide (SO_3), which reacts with water to give sulfuric acid (H_2SO_4), a contributor to acid precipitation. Sulfuric acid reacts with basic substances to give sulfates, which are fine particulates that contribute to PM-10 and visibility reduction. Sulfur oxide emissions also contribute to corrosion of the engine parts.[2,3]

Table 3.4-1 contains gaseous emission factors for the pollutants discussed above, expressed in units of pounds per horsepower-hour (lb/hp-hr), and pounds per million British thermal unit (lb/MMBtu). Table 3.4-2 shows the particulate and particle-sizing emission factors. Table 3.4-3 shows the speciated organic compound emission factors and Table 3.4-4 shows the emission factors for polycyclic aromatic hydrocarbons (PAH). These tables do not provide a complete speciated organic compound and PAH listing because they are based only on a single engine test; they are to be used only for rough order of magnitude comparisons.

Table 3.4-5 shows the NO_x reduction and fuel consumption penalties for diesel and dual-fueled engines based on some of the available control techniques. The emission reductions shown are those that have been demonstrated. The effectiveness of controls on a particular engine will depend on the specific design of each engine, and the effectiveness of each technique could vary considerably. Other NO_x control techniques exist but are not included in Table 3.4-5. These techniques include internal/external exhaust gas recirculation, combustion chamber modification, manifold air cooling, and turbocharging.

3.4.4 Control Technologies

Control measures to date are primarily directed at limiting NO_x and CO emissions since they are the primary pollutants from these engines. From a NO_x control viewpoint, the most important distinction between different engine models and types of reciprocating engines is whether they are rich-burn or lean-burn. Rich-burn engines have an air-to-fuel ratio operating range that is near stoichiometric or fuel-rich of stoichiometric and as a result the exhaust gas has little or no excess oxygen. A lean-burn engine has an air-to-fuel operating range that is fuel-lean of stoichiometric; therefore, the exhaust from these engines is characterized by medium to high levels of O_2. The most common NO_x control technique for diesel and dual fuel engines focuses on modifying the combustion process. However, selective catalytic reduction (SCR) and nonselective catalytic reduction (NSCR) which are post-combustion techniques are becoming available. Control for CO have been partly adapted from mobile sources.[5]

Combustion modifications include injection timing retard (ITR), preignition chamber combustion (PCC), air-to-fuel ratio, and derating. Injection of fuel into the cylinder of a CI engine initiates the combustion process. Retarding the timing of the diesel fuel injection causes the combustion process to occur later in the power stroke when the piston is in the downward motion and

combustion chamber volume is increasing. By increasing the volume, the combustion temperature and pressure are lowered, thereby lowering NO_x formation. ITR reduces NO_x from all diesel engines; however, the effectiveness is specific to each engine model. The amount of NO_x reduction with ITR diminishes with increasing levels of retard.[5]

Improved swirl patterns promote thorough air and fuel mixing and may include a precombustion chamber (PCC). A PCC is an antechamber that ignites a fuel-rich mixture that propagates to the main combustion chamber. The high exit velocity from the PCC results in improved mixing and complete combustion of the lean air/fuel mixture which lowers combustion temperature, thereby reducing NO_x emissions.[5]

The air-to-fuel ratio for each cylinder can be adjusted by controlling the amount of fuel that enters each cylinder. At air-to-fuel ratios less than stoichiometric (fuel-rich), combustion occurs under conditions of insufficient oxygen which causes NO_x to decrease because of lower oxygen and lower temperatures. Derating involves restricting engine operation to lower than normal levels of power production for the given application. Derating reduces cylinder pressures and temperatures thereby lowering NO_x formation rates.[5]

SCR is an add-on NO_x control placed in the exhaust stream following the engine and involves injecting ammonia (NH_3) into the flue gas. The NH_3 reacts with the NO_x in the presence of a catalyst to form water and nitrogen. The effectiveness of SCR depends on fuel quality and engine duty cycle (load fluctuations). Contaminants in the fuel may poison or mask the catalyst surface causing a reduction or termination in catalyst activity. Load fluctuations can cause variations in exhaust temperature and NO_x concentration which can create problems with the effectiveness of the SCR system.[5]

NSCR is often referred to as a three-way conversion catalyst system because the catalyst reactor simultaneously reduces NO_x, CO, and HC and involves placing a catalyst in the exhaust stream of the engine. The reaction requires that the O_2 levels be kept low and that the engine be operated at fuel-rich air-to-fuel ratios.[5]

3.4.5 Updates Since the Fifth Edition

The Fifth Edition was released in January 1995. Revisions to this section since that date are summarized below. For further detail, consult the memoranda describing each supplement or the background report for this section.

Supplement A, February 1996

No changes.

Supplement B, October 1996

- The general text was updated.
- Controlled NO_x factors and PM factors were added for diesel units.
- Math errors were corrected in factors for CO from diesel units and for uncontrolled NO_x from dual fueled units.

Table 3.4-1. GASEOUS EMISSION FACTORS FOR LARGE STATIONARY DIESEL AND ALL STATIONARY DUAL-FUEL ENGINES[a]

Pollutant	Diesel Fuel (SCC 2-02-004-01)			Dual Fuel[b] (SCC 2-02-004-02)		
	Emission Factor (lb/hp-hr) (power output)	Emission Factor (lb/MMBtu) (fuel input)	EMISSION FACTOR RATING	Emission Factor (lb/hp-hr) (power output)	Emission Factor (lb/MMBtu) (fuel input)	EMISSION FACTOR RATING
NO_x						
Uncontrolled	0.024	3.2	B	0.018	2.7	D
Controlled	0.013[c]	1.9[c]	B	ND	ND	NA
CO	5.5 E-03	0.85	C	7.5 E-03	1.16	D
SO_x[d]	8.09 E-03S_1	1.01S_1	B	4.06 E-04S_1 + 9.57 E-03S_2	0.05S_1 + 0.895S_2	B
CO_2[e]	1.16	165	B	0.772	110	B
PM	0.0007[c]	0.1[c]	B	ND	ND	NA
TOC (as CH_4)	7.05 E-04	0.09	C	5.29 E-03	0.8	D
Methane	f	f	E	3.97 E-03	0.6	E
Nonmethane	f	f	E	1.32 E-03	0.2[g]	E

[a] Based on uncontrolled levels for each fuel, from References 2,6-7. When necessary, the average heating value of diesel was assumed to be 19,300 Btu/lb with a density of 7.1 lb/gallon. The power output and fuel input values were averaged independently from each other, because of the use of actual brake-specific fuel consumption (BSFC) values for each data point and of the use of data possibly sufficient to calculate only 1 of the 2 emission factors (e. g., enough information to calculate lb/MMBtu, but not lb/hp-hr). Factors are based on averages across all manufacturers and duty cycles. The actual emissions from a particular engine or manufacturer could vary considerably from these levels. To convert from lb/hp-hr to kg/kw-hr, multiply by 0.608. To convert from lb/MMBtu to ng/J, multiply by 430. SCC = Source Classification Code.

[b] Dual fuel assumes 95% natural gas and 5% diesel fuel.

[c] References 8-26. Controlled NO_x is by ignition timing retard.

[d] Assumes that all sulfur in the fuel is converted to SO_2. S_1 = % sulfur in fuel oil; S_2 = % sulfur in natural gas. For example, if sulfer content is 1.5%, then S = 1.5.

[e] Assumes 100% conversion of carbon in fuel to CO_2 with 87 weight % carbon in diesel, 70 weight % carbon in natural gas, dual-fuel mixture of 5% diesel with 95% natural gas, average BSFC of 7,000 Btu/hp-hr, diesel heating value of 19,300 Btu/lb, and natural gas heating value of 1050 Btu/scf.

[f] Based on data from 1 engine, TOC is by weight 9% methane and 91% nonmethane.

[g] Assumes that nonmethane organic compounds are 25% of TOC emissions from dual-fuel engines. Molecular weight of nonmethane gas stream is assumed to be that of methane.

Table 3.4-2. PARTICULATE AND PARTICLE-SIZING EMISSION FACTORS FOR LARGE UNCONTROLLED STATIONARY DIESEL ENGINES[a]

EMISSION FACTOR RATING: E

Pollutant	Emission Factor (lb/MMBtu) (fuel input)
Filterable particulate[b]	
< 1 μm	0.0478
< 3 μm	0.0479
< 10 μm	0.0496
Total filterable particulate	0.0620
Condensable particulate	0.0077
Total PM-10[c]	0.0573
Total particulate[d]	0.0697

[a] Based on 1 uncontrolled diesel engine from Reference 6. Source Classification Code 2-02-004-01. The data for the particulate emissions were collected using Method 5, and the particle size distributions were collected using a Source Assessment Sampling System. To convert from lb/MMBtu to ng/J, multiply by 430. PM-10 = particulate matter ≤ 10 micrometers (μm) aerometric diameter.

[b] Particle size is expressed as aerodynamic diameter.

[c] Total PM-10 is the sum of filterable particulate less than 10 μm aerodynamic diameter and condensable particulate.

[d] Total particulate is the sum of the total filterable particulate and condensable particulate.

Table 3.4-3. SPECIATED ORGANIC COMPOUND EMISSION FACTORS FOR LARGE UNCONTROLLED STATIONARY DIESEL ENGINES[a]

EMISSION FACTOR RATING: E

Pollutant	Emission Factor (lb/MMBtu) (fuel input)
Benzene[b]	7.76 E-04
Toluene[b]	2.81 E-04
Xylenes[b]	1.93 E-04
Propylene	2.79 E-03
Formaldehyde[b]	7.89 E-05
Acetaldehyde[b]	2.52 E-05
Acrolein[b]	7.88 E-06

[a]Based on 1 uncontrolled diesel engine from Reference 7. Source Classification Code 2-02-004-01. Not enough information to calculate the output-specific emission factors of lb/hp-hr. To convert from lb/MMBtu to ng/J, multiply by 430.
[b]Hazardous air pollutant listed in the *Clean Air Act*.

Table 3.4-4. PAH EMISSION FACTORS FOR LARGE UNCONTROLLED STATIONARY DIESEL ENGINES[a]

EMISSION FACTOR RATING: E

PAH	Emission Factor (lb/MMBtu) (fuel input)
Naphthalene[b]	1.30 E-04
Acenaphthylene	9.23 E-06
Acenaphthene	4.68 E-06
Fluorene	1.28 E-05
Phenanthrene	4.08 E-05
Anthracene	1.23 E-06
Fluoranthene	4.03 E-06
Pyrene	3.71 E-06
Benz(a)anthracene	6.22 E-07
Chrysene	1.53 E-06
Benzo(b)fluoranthene	1.11 E-06
Benzo(k)fluoranthene	<2.18 E-07
Benzo(a)pyrene	<2.57 E-07
Indeno(1,2,3-cd)pyrene	<4.14 E-07
Dibenz(a,h)anthracene	<3.46 E-07
Benzo(g,h,l)perylene	<5.56 E-07
TOTAL PAH	<2.12 E-04

[a] Based on 1 uncontrolled diesel engine from Reference 7. Source Classification Code 2-02-004-01. Not enough information to calculate the output-specific emission factors of lb/hp-hr. To convert from lb/MMBtu to ng/J, multiply by 430.

[b] Hazardous air pollutant listed in the *Clean Air Act*.

Table 3.4-5. NO_x REDUCTION AND FUEL CONSUMPTION PENALTIES FOR LARGE STATIONARY DIESEL AND DUAL-FUEL ENGINES[a]

Control Approach		Diesel (SCC 2-02-004-01)		Dual Fuel (SCC 2-02-004-02)	
		NO_x Reduction (%)	ΔBSFC[b] (%)	NO_x Reduction (%)	ΔBSFC (%)
Derate	10%	ND	ND	<20	4
	20%	<20	4	ND	ND
	25%	5 - 23	1 - 5	1 - 33	1 - 7
Retard	2°	<20	4	<20	3
	4°	<40	4	<40	1
	8°	28 - 45	2 - 8	50 - 73	3 - 5
Air-to-fuel	3%	ND	ND	<20	0
	±10%	7 - 8	3	25 - 40	1 - 3
Water injection (H_2O/fuel ratio)	50%	25 - 35	2 - 4	ND	ND
SCR		80 - 95	0	80 - 95	0

[a] References 1,27-28. The reductions shown are typical and will vary depending on the engine and duty cycle. SCC = Source Classification Code. ΔBSFC = change in brake-specific fuel consumption. ND = no data.

References For Section 3.4

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2. *Standards Support And Environmental Impact Statement, Volume I: Stationary Internal Combustion Engines*, EPA-450/2-78-125a, U. S. Environmental Protection Agency, Research Triangle Park, NC, July 1979.

3. M. Hoggan, et. al., *Air Quality Trends in California's South Coast and Southeast Desert Air Basins, 1976-1990*, "Air Quality Management Plan, Appendix II-B", South Coast Air Quality Management District, July 1991.

4. *Limiting Net Greenhouse Gas Emissions In the United States, Volume II: Energy Responses,* report for the Office of Environmental Analysis, Office of Policy, Planning and Analysis, Department of Energy (DDE), DOE/PE-0101 Volume II, September 1991.

5. Snyder, R. B., *Alternative Control Techniques Document—NO_x Emissions from Stationary Reciprocating Internal Combustion Engines*, EPA-453/R-93-032, U. S. Environmental Protection Agency, Research Triangle Park, July 1993.

6. C. Castaldini, *Environmental Assessment Of NO_x Control On A Compression Ignition Large Bore Reciprocating Internal Combustion Engine, Volume I: Technical Results*, EPA-600/7-86/001a, U. S. Environmental Protection Agency, Cincinnati, OH, April 1984.

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8. *Final Report For An Emission Compliance Test Program On Two Standby Generators Located At American Car Company*, Greenwich, CT, York Services Corp., 1987.

9. *Final Report For An Emission Compliance Test Program On A Standby Diesel Generator At South Central Connecticut Regional Water Authority*, West Haven, CT, York Services Corp., 1988.

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11. *Compliance Test Report For Particulate Emissions From A Caterpillar Diesel Generator,* St. Mary's Hospital, Waterburg, CT, TRC Environmental Consultants, 1987.

12. *Compliance Measured Particulate Emissions From An Emergency Diesel Generator, Silorsky Aircraft, United Technologies*, Stratford, CT, TRC Environmental Consultants, 1987.

13. *Compliance Test Report For Particulate Emissions From A Cummins Diesel Generator*, Colonial Gold Limited Partnership, Hartford, CT, TRC Environmental Consultants, 1988.

14. *Compliance Test Report For Particulate Emissions From A Cummins Diesel Generator*, CIGNA Insurance Company, Bloomfield, CT, TRC Environmental Consultants, 1988.

15. *Compliance Test Report For Particulate Emission From A Waukesha Diesel Generator*, Bristol Meyers, Wallinsford, CT, TRC Environmental Consultants, 1987.

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17. *Compliance Measured Particulate Emissions From An Emergency Diesel Generator*, Danbury Hospital, Danbury, CT, TRC Environmental Consultants, 1988.

18. *Compliance Test Report For Particulate Emissions From A Caterpillar Diesel Generator*, Colonial Metro Limited Partnership, Hartford, CT, TRC Environmental Consultants, 1988.

19. *Compliance Test Report For Particulate Emissions From A Caterpillar Diesel Generator*, Boehringer -Ingelheim Pharmaceuticals, Danbury, CT, TRC Environmental Consultants, 1988.

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21. *Compliance Test Report Johnson Memorial Hospital Emergency Generator Exhaust Stack*, Stafford Springs, CT, ROJAC Environmental Services, 1987.

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ECMPS Client Tool

Version 1.0 2017 Q4

United States Environmental Protection Agency (EPA)
Emissions Collection and Monitoring Plan System (ECMPS) Feedback

January 5, 2018 01:59 PM

Re: Brandywine Power Facility (54832) - 1

Dear Certifying Official:

Thank you for submitting your Quarterly Emissions Report using the U. S. EPA`s Emissions Collection and Monitoring Plan System (ECMPS) software. This ECMPS Feedback report provides you with a detailed submission receipt, a summary of the evaluations performed on your submission, and guidance on any follow-up actions needed if any errors were found. EPA has also received a copy of this Feedback Report as part of your submission.

SUBMISSION STATUS

The EPA has received your Quarterly Emissions Report for the Facility and Monitoring Location(s) listed in Table 1 below. The Table also provides confirmation of EPA`s receipt (Date, Time, etc.) of your submission. Prior to submission ECMPS evaluated your emissions report and assigned an overall "Error Status Level" to it, based on the results (see Table 1). This Feedback Report also contains Table 2, which displays EPA-Accepted Cumulative Values for emissions and other parameters. Finally, a summary of ECMPS`s Evaluation Results is included.

Table 1: Submission Receipt and Error Status Level Information

Report Received for Facility ID (ORIS Code):	54832
Facility Name:	Brandywine Power Facility
State:	MD
Monitoring Locations:	1
Submission Type:	EM for 2017 QTR 4
Error Status Level:	Administrative Override
Submission Date/Time:	01/05/2018 1:59:21 PM
Submitter User ID:	JMclvo11
Submission ID:	1121792
Resubmission Required:	No
EPA Analyst:	Charles Frushour; (202) 343-9847; frushour.charles@epa.gov

EXPLANATION OF YOUR ERROR STATUS LEVEL LISTED IN TABLE 1

The EPA has accepted your Emissions submission. ECMPS detected errors in your data based on the checks performed; however, the Evaluation Results at the end of this Feedback Report indicate that one or more of the errors have been "Administratively Overridden." Errors that have been administratively overridden by EPA do not require a resubmission or any further action; they are listed in the evaluation results portion of the feedback for informational purposes. NOTE: the ECMPS submission access window for this Emissions report has been closed. If you need to resubmit this data, please see the DATA RESUBMISSION guidance, below.

OTHER INFORMATION AND BULLETINS FROM EPA

QUESTIONS: Please contact your EPA Analyst listed in Table 1 with any questions regarding this submission and the evaluation results. If you need assistance with correcting problems in the Emissions data for this facility, please send an e-mail to ECMPS Technical Support at: ecmps-support@camdsupport.com.

DATA RESUBMISSION: If you need to resubmit Emissions data, including for previous calendar quarters, please complete the ECMPS Data Resubmission Request Form at: http://ecmps.camdsupport.com/help_resubmit_form.shtml. Please provide detailed documentation of the reasons for the resubmission. Support staff will review your request and notify you via e-mail when the necessary database access window has been granted for your resubmission.

TECHNICAL SUPPORT: please visit the ECMPS Technical Support website at: http://ecmps.camdsupport.com for information about ECMPS software downloads, ECMPS News, Technical Support, documentation, tutorials, FAQs, and more.

ECMPS Data Reporting Instructions: for detailed information about reporting Monitoring Plan, QA/Certification Test, and Emissions data, please see the ECMPS Reporting Instructions on the EPA`s website at: http://www.epa.gov/airmarkets/business/ecmps/reporting-instructions.html.

If you have any questions regarding this correspondence, please feel free to contact your EPA Analyst listed in Table 1 as soon as possible. Thank you for your attention to this matter.

Table 2: Cumulative Data Summary -- EPA-Accepted Values

Unit/Stack/Pipe ID: 1

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Ozone Season	Year-to-Date
Number of Operating Hours	0	953	1,352	1,175	1,980	3,480
Operating Time (hrs)	0.00	898.04	1,319.49	1,146.19	1,907.73	3,363.72
SO2 Mass (tons)	0.0	0.2	0.3	0.3		0.8
CO2 Mass (tons)	0.0	42,478.6	61,994.1	51,521.4		155,994.1
Heat Input (mmBtu)	0	714,266	1,042,398	866,535	1,517,026	2,623,199
NOx Emission Rate (lb/mmBtu)	0.000	0.038	0.028	0.031		0.032
NOx Mass (tons)	0.0	10.3	12.8	11.7	19.5	34.8

ECMPS Client Tool

Version 1.0 2017 Q4

United States Environmental Protection Agency (EPA)
Emissions Collection and Monitoring Plan System (ECMPS) Feedback

January 5, 2018 02:00 PM

Re: Brandywine Power Facility (54832) - 2

Dear Certifying Official:

Thank you for submitting your Quarterly Emissions Report using the U. S. EPA`s Emissions Collection and Monitoring Plan System (ECMPS) software. This ECMPS Feedback report provides you with a detailed submission receipt, a summary of the evaluations performed on your submission, and guidance on any follow-up actions needed if any errors were found. EPA has also received a copy of this Feedback Report as part of your submission.

SUBMISSION STATUS

The EPA has received your Quarterly Emissions Report for the Facility and Monitoring Location(s) listed in Table 1 below. The Table also provides confirmation of EPA`s receipt (Date, Time, etc.) of your submission. Prior to submission ECMPS evaluated your emissions report and assigned an overall "Error Status Level" to it, based on the results (see Table 1). This Feedback Report also contains Table 2, which displays EPA-Accepted Cumulative Values for emissions and other parameters. Finally, a summary of ECMPS`s Evaluation Results is included.

Table 1: Submission Receipt and Error Status Level Information

Report Received for Facility ID (ORIS Code):	54832
Facility Name:	Brandywine Power Facility
State:	MD
Monitoring Locations:	2
Submission Type:	EM for 2017 QTR 4
Error Status Level:	Administrative Override
Submission Date/Time:	01/05/2018 2:00:26 PM
Submitter User ID:	JMclvo11
Submission ID:	1121795
Resubmission Required:	No
EPA Analyst:	Charles Frushour; (202) 343-9847; frushour.charles@epa.gov

EXPLANATION OF YOUR ERROR STATUS LEVEL LISTED IN TABLE 1

The EPA has accepted your Emissions submission. ECMPS detected errors in your data based on the checks performed; however, the Evaluation Results at the end of this Feedback Report indicate that one or more of the errors have been "Administratively Overridden." Errors that have been administratively overridden by EPA do not require a resubmission or any further action; they are listed in the evaluation results portion of the feedback for informational purposes. NOTE: the ECMPS submission access window for this Emissions report has been closed. If you need to resubmit this data, please see the DATA RESUBMISSION guidance, below.

OTHER INFORMATION AND BULLETINS FROM EPA

QUESTIONS: Please contact your EPA Analyst listed in Table1 with any questions regarding this submission and the evaluation results. If you need assistance with correcting problems in the Emissions data for this facility, please send an e-mail to ECMPS Technical Support at: ecmps-support@camdsupport.com.

DATA RESUBMISSION: If you need to resubmit Emissions data, including for previous calendar quarters, please complete the ECMPS Data Resubmission Request Form at: http://ecmps.camdsupport.com/help_resubmit_form.shtml. Please provide detailed documentation of the reasons for the resubmission. Support staff will review your request and notify you via e-mail when the necessary database access window has been granted for your resubmission.

TECHNICAL SUPPORT: please visit the ECMPS Technical Support website at: http://ecmps.camdsupport.com for information about ECMPS software downloads, ECMPS News, Technical Support, documentation, tutorials, FAQs, and more.

ECMPS Data Reporting Instructions: for detailed information about reporting Monitoring Plan, QA/Certification Test, and Emissions data, please see the ECMPS Reporting Instructions on the EPA`s website at: http://www.epa.gov/airmarkets/business/ecmps/reporting-instructions.html.

If you have any questions regarding this correspondence, please feel free to contact your EPA Analyst listed in Table 1 as soon as possible. Thank you for your attention to this matter.

Table 2: Cumulative Data Summary -- EPA-Accepted Values

Unit/Stack/Pipe ID: 2

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Ozone Season	Year-to-Date
Number of Operating Hours	701	945	1,399	1,251	2,011	4,296
Operating Time (hrs)	672.43	886.05	1,362.38	1,217.61	1,934.56	4,138.47
SO2 Mass (tons)	0.2	0.2	0.3	0.3		1.0
CO2 Mass (tons)	31,889.3	40,148.1	60,840.7	50,317.6		183,195.7
Heat Input (mmBtu)	536,068	674,676	1,023,092	845,894	1,464,691	3,079,730
NOx Emission Rate (lb/mmBtu)	0.039	0.040	0.030	0.032		0.034
NOx Mass (tons)	8.3	10.3	13.5	11.7	20.0	43.8

Fuel Quality Services, Inc.

P.O. Box 1380, Flowery Branch, GA. 30542-0023 • Phone: 800-827-9790 or 770-967-9790 • Fax: 770-967-9982

September 20, 2017

Brandywine Power (KMC)
Attn: Doug Sears
16400 Mattawan Drive
Brandywine, MD 20613

Chain of Custody

Number of Fuel Samples Received: **(1) 32oz Middle Sample** **(2) 16oz Bottom Samples** **Fuel Sample Type: Diesel**	**Fuel Samples Pulled On: Unknown** **Fuel Samples Arrived at FQS: 8/29/2017** **Fuel Received by: Scott Kaye** **Fuel Samples Shipped to Lab: 8/29/2017** **Fuel Sample Location: Brandywine, MD (Tank: 1)**

Fuel Analysis Results

Tank ID: 1

Middle Sample Description: Clear bright red color. Sample contains 1 small water droplet; 1 tiny particle of debris visible.

Bottom Sample Description: Clear bright red color. Sample contains no visible water; some small debris visible.

Test Method	Acceptable Values	Measured Results
Microbial (ASTM D7463): Reported in RLU HY-LiTE® Rapid Microbial Test For Fuel Systems Test results are within acceptable limits. We recommend continued surveillance and treating with FQS 1.5 Microbicide (Treat Ratio 1:10,000) as needed.	< 5000 RLU	520 RLU
Oxidation Stability (ASTM D7545): Reported in minutes [Induction period < 60 minutes indicates a tendency toward instability during high thermal stress.] [Induction period > 60 minutes indicates a tendency towards stability during high thermal stress.] The test result indicates that the ULSD has a tendency toward stability. We recommend testing again in 6-12 months. Please note, diesel fuel additives such as biodiesel for lubricity or ethyl hexyl nitrate to improve cetane can negatively affect test results.	>60min	87 min
Particulate (ASTM D7321): Reported as mg/L [15-20 mg/L range - at risk for filter plugging] Results are normalized to 1000mL sample volume. Results are within acceptable guideline for diesel fuel.	wt. < 15 mg/L	9.2 mg/L

Test Method		Measured Results
Heat of Combustion, GROSS (ASTM D240)		
	(BTUHeat/LB) - BTU/lb	19556
	(BTUHeat/GAL) - BTU/gal	133870
	(MJHeat/KG) - MJ/kg	45.49
	(CALHeat/G) - Cal/g	10864.2
Heat of Combustion, NET (ASTM D240)		
	(BTUHeat/LB) - BTU/lb	18328
	(BTUHeat/GAL) - BTU/gal	128241
	(MJHeat/KG) - MJ/kg	42.63
	(CALHeat/G) - Cal/g	10181.9
Sulfur Content (ASTM D7039)	ppm Wt	9
Density (ASTM D4052)		
	API @60F	37.0
	Specific Gravity @60F	0.8399
	Density @15C (g/ml)	0.8395
Carbon/Hydrogen (ASTM D5291)		
	Carbon, wt.%	86.28
	Hydrogen, wt.%	13.46
Nitrogen CHM (ASTM D4629)		
	Nitrogen, ppm	3.4

Report Summary / Recommendations

Analysis was performed in accordance with the test procedures specified above with no deviation or modification. The analysis pertains only to the samples tested and represent only a sampling of a batch. As part of a good fuel maintenance program, it is recommended to sample and test the fuel again within 6-12 months to monitor condition of the fuel.

If you have any questions regarding the information contained in this report, please contact us at (770) 967-9790.

Sincerely,
Melissa Broxson

Fuel Quality Services, Inc.
P.O. Box 1380, Flowery Branch GA 30542-0023
Phone: (800) 827-9790 / (770) 967-9790 Fax: (770) 967-9982
Website: www.fqsinc.com

Heather McKee

From: TrackingUpdates@fedex.com
Sent: Wednesday, March 07, 2018 10:01 AM
To: Heather McKee
Subject: FedEx Shipment 771732024519 Delivered

Your package has been delivered

Tracking # 771732024519

Ship date:
Tue, 3/6/2018

HEATHER MCKEE
KMC Thermo LLC
Brandywine, MD 20613
US

Delivered

Delivery date:
Wed, 3/7/2018 9:56 am

LARAMIE DANIEL
Maryland Dept of the Environment
1800 Washington Blvd. Suite 715
Air & Radiation Management Admin.
BALTIMORE, MD 21230
US

Shipment Facts

Our records indicate that the following package has been delivered.

Tracking number:	771732024519
Status:	Delivered: 03/07/2018 09:56 AM Signed for By: O.SABASA
Reference:	2017 Part 70 Comp Cert Report
Signed for by:	O.SABASA
Delivery location:	BALTIMORE, MD
Delivered to:	Shipping/Receiving
Service type:	FedEx Express Saver
Packaging type:	FedEx Pak
Number of pieces:	1
Weight:	1.00 lb.
Special handling/Services:	Deliver Weekday

ATTACHMENT D
2017 ANNUAL COMPLIANCE CERTIFICATION REPORT

Brandywine POWER

A KMC Thermo, LLC Company

Monday, March 5, 2018

Ms. Laramie Daniel, Compliance Program
Maryland Department of the Environment - ARMA
1800 Washington Boulevard, Suite 715
Baltimore, MD 21230-1720

Re: Brandywine Power Facility - Facility number 033-02200
2017 Part 70 Compliance Certification Report

Dear Ms. Daniel,

Attached is the 2017 Part 70 Permit Compliance Certification Report for the Brandywine Power Facility.

A copy of this report is also being sent to the Associate Director in the Office of Enforcement and Permit Review at EPA's Region III office.

Please contact myself or Mark Briggs if there are any questions in regard to this report.

Sincerely,

Mike Fulcher
Asset Manager

MF/mtb

cc: Associate Director, EPA Region III (via email)
file, MDE communication
file, United States EPA - NOx

16400 Mattawoman Drive Brandywine, Maryland 20613
301-782-4000 Fax 301-782-4004

EPA United States Environmental Protection Agency

OMB No. 2060-0336,
Approval Expires 05/31/2019

Federal Operating Permit Program (40 CFR Part 71)
CERTIFICATION OF TRUTH, ACCURACY, AND COMPLETENESS (CTAC)

This form must be completed, signed by the "Responsible Official" designated for the facility or emission unit, and sent with each submission of documents (i.e., application forms, updates to applications, reports, or any information required by a part 71 permit).

A. Responsible Official

Name: (Last) Fulcher (First) Mike (MI) _____

Title Asset Manager

Street or P.O. Box 16400 Mattawoman Drive

City Brandywine State MD ZIP 20613

Telephone (301) 782-4000 Ext. _____ Facsimile (301)782 - 4004

B. Certification of Truth, Accuracy and Completeness (to be signed by the responsible official)

I certify under penalty of law, based on information and belief formed after reasonable inquiry, the statements and information contained in these documents are true, accurate and complete.

Name (signed) _____

Name (typed) Mike Fulcher Date: 3 / 5 / 2018

EPA United States Environmental Protection Agency

OMB No. 2060-0336,
Approval Expires 05/31/2019

Federal Operating Permit Program (40 CFR Part 71)
ANNUAL COMPLIANCE CERTIFICATION (A-COMP)

A. GENERAL INFORMATION

Permit No. 24-033-02200

Reporting Period: Beg. 01 / 01 / 2017 End. 12 / 31 / 2017

Source / Company Name KMC Thermo, LLC

Mailing Address: Street or P.O. Box 16400 Mattawoman Drive

City Brandywine State MD ZIP 20613 - 8089

Contact person Mark Briggs Title General Manager

Telephone (301) 782 - 4000 Ext.

Continued on next page

B. COMPLIANCE STATUS

Describe the compliance status of each permit term for the reporting period. Copy this page as many times as necessary to cover all permit terms and conditions.

Emission Unit ID(s): **EU-1 and EU-2**

Permit Term (Describe requirements and cross-reference)

VISIBLE EMISSIONS FROM FUEL BURNING EQUIPMENT

SECTION IV-1 - PLANT SPECIFIC CONDITIONS

Subsection: 1.1, A. Limits: (each turbine)

Except for emissions during load changing, soot blowing, startup, Black Start Events or occasional cleaning of control equipment: (**1.**) visible emissions < 40% opacity, (**2.**) visible emissions do not occur for more than 6 minutes in any 60 minute period.

Subsection: 1.2, A. Testing Requirements: (See monitoring)

Subsection: 1.3, A. Monitoring Requirements:

Properly operate and maintain the combustion turbines; Maintain an Operations manual and Preventive Maintenance plan; Verify no visible emissions when burning ULSD fuel oil. Perform at least one EPA Reference Method 9 observation of stack emissions for a 6 minute period once for each 168 hours that each of the combustion turbines burns ULSD fuel oil. If a turbine operates on ULSD fuel oil for less than 168 hours in a year, this observation requirement is waived for that calendar year.

If visible emissions are observed: Inspect combustion turbine operations; Perform all necessary adjustments and/or repairs to the turbines within 48 hours that visible emissions are eliminated; document in writing the results of the inspections, adjustments and/or repairs to the turbines; and if the required adjustments and/or repairs have not eliminated the visible emissions within the stipulated 48 hours, perform a Method 9 observation once daily for 18 minutes until corrective action has eliminated the visible emissions.

Subsection: 1.4, A. Record Keeping Requirements:

Maintain a log of maintenance performed that relates to combustion performance on the combustion turbines; and maintain a log of visible emissions observation performed on site for 5 years.

Subsection: 1.5, A. Reporting Requirements:

Report incidents of visible emissions

Compliance Methods for the Above (Description and Citation):

Gas turbines were properly maintained and operated during the reporting period. An operations manual was maintained and a maintenance plan was followed during the reporting period. Turbine emissions were continuously visually monitored for visible emissions. Visible emissions testing was performed (August, 2017) by an independent, third-party company prior to the 168-hour fuel-oil operation limitation being reached. Records of all testing and maintenance are kept on site for a minimum of 5 years. A record of the number of hours during which fuel-oil is combusted in gas turbines is maintained. Results of visible emissions testing, CEMS RATAs, fuel-oil sulfur content analyses, Quarterly, SIX-MON and Annual Emissions Reports are all submitted to the Maryland Department of the Environment.

Status (Check one):____Intermittent Compliance ✓ Continuous Compliance

Emission Unit ID(s): **EU-1 and EU-2**

Permit Term (Describe requirements and cross-reference)

SULFUR CONTENT IN FUEL OIL BURNED IN GAS TURBINES

SECTION IV-1 - PLANT SPECIFIC CONDITIONS

Subsection:1.1, B. Limits: (each turbine)

(B1) Sulfur content in ULSD fuel oil limited to 0.0015 wt %.
(B2) Except during start-up, shut-down, malfunction, and Black Start Events limited to the following hourly emissions:
Sulfur Oxides (as SO_2): 29 lbs/hr (Natural Gas), 29 lbs/hr (LNG), 54 lbs/hr (ULSD Fuel Oil)
(B3) Sulfuric Acid Mist: 3 lbs/hr (Natural Gas), 3 lbs/hr (LNG), 6 lbs/hr (ULSD Fuel Oil)
(B4) Sulfur content in any fuel burned in a gas turbine limited to 0.8 wt. %.
(B5) Comply with the provisions and applicable requirements of the Phase II Acid Rain program.
(B6) Comply with the provisions in 40 CFR §§97.601-97.635.

Subsection:1.2, B. Testing Requirements:

Perform sampling and analysis of the ULSD fuel oil to determine percentage of sulfur by weight
Perform QA/QC procedures for SO_2 monitoring

Subsection 1.3, B. Monitoring Requirements:

Perform sampling and analysis of the sulfur content of the ULSD fuel oil to determine the percentage of sulfur by weight.
Natural Gas: Use one of the following: (a.) The gas quality characteristics in a current valid purchase contract, tariff sheet or transportation contract for the gaseous fuel, specifying that the maximum total sulfur content of the fuel is 20.0 grains /100 scf or less; or (b). Representative fuel sampling data, which show that the sulfur content of the gaseous fuel does not exceed 20-grains/100 scf.
For Oil: The frequency of determining the sulfur (and nitrogen) content of the ULSD fuel oil is as follows:
Use one of the total sampling options and associated sampling frequency described in sections 2.2.3, 2.2.4.1, 2.2.4.2, and 2.2.2.4.3 of appendix D to part 75 of this chapter (i.e., flow proportional sampling, daily sampling, sampling from the unit's storage tank after each addition of the fuel to the tank, or sampling each delivery prior to combining it with fuel oil already in the intended storage tank.
Comply with the monitoring requirements in §97.606, §97.630, §97.631, §97.632, and §97.633.

Subsection: 1.4, B. Record Keeping Requirements:

Maintain all records including the fuel analyses for 2 years.
Note: Part 70 permits require records to be maintained for 5 years.
Comply with the recordkeeping requirements in §97.606, §97.630, and §97.634.

Subsection: 1.5, B. Reporting Requirements:

Quarterly Report (including excess emissions and monitor downtime)
Note: For any calendar quarter during which no delivery of ULSD fuel oil is received, the quarterly report shall state that no ULSD fuel oil was receive during the quarter.

Compliance Methods for the Above (Description and Citation):

Samples of fuel oil received by the facility are tested by an off-site laboratory to ensure it meets the sulfur content limitation. During the reporting period, approximately 105,064 gallons of ULSD fuel oil were received by the facility. After which, fuel oil sampling of the facility storage tank was performed and analyzed for sulfur content per 40 CFR 75, Appendix D, Section 2.2. The lab analysis report was included in the 3rd Quarter 2017 Emissions Report to the MDE. Records of fuel oil analysis are kept for at least 5 years. Natural gas supplied to the plant is of pipeline-quality, the content of which is controlled by a state & federally-approved tariff structure; maximum sulfur content of the fuel is dictated by the tariff to be less than 20 grains per standard cubic foot.

Status (Check one): ___Intermittent Compliance _✓_Continuous Compliance

Emission Unit ID(s): **EU-1 and EU-2**

Permit Term (Describe requirements and cross-reference)

NITROGEN OXIDE (NOx) EMISSIONS FROM GAS TURBINES

SECTION IV-1 - PLANT SPECIFIC CONDITIONS

Subsection: 1.1, C. Limits: (each turbine)

(C1) Except during start-up period, shut-down, malfunction, and Black Start Events hourly emissions shall be limited to:

NO_X**:** 9 ppmvd @ 15% O_2 (NG), 10 ppmvd @ 15% O_2 (LNG); 54 ppmvd @ 15% O_2 (ULSD Fuel Oil)

(C2) Except during start-up period, shut-down, malfunction, and Black Start Events hourly emissions shall be limited to: NO_X**:** 35 lbs/hr (NG); 39 lbs/hr (LNG); 239 lbs/hr (ULSD Fuel Oil)

(C3) Excluding emissions during start-up period, shut-down, malfunction or PJM system emergency or Black Start Events: annual facility-wide NO_X emissions shall be limited to 437 tons per year (as NO_2). Under no circumstance shall facility-wide NO_X emissions exceed 518 tons per year.

(C4) NSPS: Except during start-up, shut-down, malfunction, and Black Start Events hourly emissions shall be limited to: NO_X**:** 144 ppmvd @15% O_2 (Natural Gas), 144 ppmvd @ 15% O_2 (LNG); 101 ppmvd @ 15% O_2 (ULSD Fuel Oil)

(C5) NOx RACT: hourly emissions rate shall be limited to:

NO_X**:** 42 ppmvd @15% O_2 (Natural Gas), 42 ppmvd @ 15% O_2 (LNG); 65 ppmvd @ 15% O_2 (ULSD Fuel Oil)

(C6) CSAPR: Shall comply with the provisions and requirements in §97.401-97.435 and 97.501-97.535.

Subsection: 1.2, C. Testing Requirements:

Perform QA/QC procedures for the NOx monitoring system

Subsection: 1.3, C. Monitoring Requirements:

Operate and maintain a CEMS to monitor the NOx emissions.

Install, certify, maintain, operate, and quality-assure a continuous emission monitoring system (CEMS) consisting of NO_X and O_2 monitors as follows: CEMS must be installed and certified according to PS 2 and 3 (for diluent) of 40 CFR part 60, appendix B, except the 7-day calibration drift is based on unit operating days, not calendar days. Appendix F, Procedure 1 is not required. The relative accuracy test audit (RATA) of the NO_X and diluent monitors may be performed individually or on a combined basis, *i.e.*, the relative accuracy tests of the CEMS may be performed either: on a ppm basis (for NO_X) and a percent O_2 basis for oxygen; or on a ppm at 15 percent O_2 basis; or on a ppm basis (for NO_X) and a percent CO_2 basis (for a CO_2 monitor that uses the procedures in Method 20 to correct the NO_X data to 15 percent O_2).Use the data collected from the NOx CEM to demonstrate compliance with the RACT limitation. Comply with the monitoring requirements found in §97.406, and §97.430-97.433, and §97.506, and §97.531-97.533.

Subsection: 1.4, C. Record Keeping Requirements:

Maintain all records necessary to comply with the NOx data reporting requirements of CPCN No. 9341, Condition 14. Maintain a record of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by this part recorded in a permanent form suitable for inspection. Maintain annual fuel use records and records that are necessary to submit the quarterly emissions report. Comply with the record keeping requirements found in §97.406, §97.430, §97.434, §97.506, §97.530, and §97.534.

Subsection: 1.5 C. Reporting Requirement for nitrogen oxide (NOx) emissions from gas turbines
Quarterly Report, (including excess emissions and monitor downtime)
Comply with the reporting requirements found in §97.406, §97.430, §97.433, §97.434, §97.506, §97.530, §97.533, and §97.534.

Compliance Methods for the Above (Description and Citation):

Both Gas turbine A (EU-1) and Gas turbine B (EU-2) were operated in accordance with state and federal limitations on NOx emissions and the NOx Budget program during the reporting period. A continuous emissions monitoring system (CEMS) was in operation at the plant and was operated in accordance with state & federal regulations during the reporting period. The CEMS undergoes a relative accuracy test audit (RATA) test annually, which is conducted by an independent, third-party company. The August, 2017 RATA was successful; no CEMS bias adjustment was required on Gas turbine A (EU-1) or Gas turbine B (EU-2). Results of visible emissions testing, CEMS RATAs, fuel-oil sulfur content analyses, Quarterly, SIX-MON and Annual Emissions Reports are all submitted to the Maryland Department of the Environment.

Status (Check one):___Intermittent Compliance __✓__ Continuous Compliance

Emission Unit ID(s): **EU-1 and EU-2**

Permit Term (Describe requirements and cross-reference)

CARBON MONOXIDE (CO) EMISSIONS FROM GAS TURBINES

SECTION IV-1 - PLANT SPECIFIC CONDITIONS

Subsection: 1.1, D. Limits: (each turbine)
Except during start-up period, shut-down, malfunction, and Black Start Events hourly emissions shall be limited to:
Carbon Monoxide: 59 lbs/hr (Natural Gas); 59 lbs/hr (LNG); 71 lbs/hr (ULSD Fuel Oil)
Subsection: 1.2, D. Testing Requirements: (See monitoring)
Subsection: 1.3, D. Monitoring Requirements:
Perform preventative maintenance on the turbines to maintain them in a condition such that they operate as designed.
Subsection: 1.4, D. Record Keeping Requirements:
Maintain records of the preventative maintenance which relate to combustion performance.
Subsection: 1.5, D. Reporting Requirements:
Submit records of the preventative maintenance performed, which relate to combustion performance to the Department upon request.

Compliance Methods for the Above (Description and Citation):

Gas turbines were properly maintained and operated during the reporting period. An operations manual was maintained and a maintenance plan was followed during the reporting period. Records of all testing and maintenance are kept on site for a minimum of 5 years. A record of the number of hours during which fuel-oil is combusted in gas turbines is maintained. Results of visible emissions testing, CEMS RATAs, fuel-oil sulfur content analyses, Quarterly, SIX-MON and Annual Emissions Reports are all submitted to the Maryland Department of the Environment.

Status (Check one):_____Intermittent Compliance __✓__Continuous Compliance

Emission Unit ID(s): **EU-1 and EU-2**

Permit Term (Describe requirements and cross-reference)

VOLITILE ORGANIC COMPOUND (VOC) EMISSIONS FROM GAS TURBINES

SECTION IV-1 - PLANT SPECIFIC CONDITIONS

Subsection: 1.1, E. Limits: (each turbine)
Except during start-up period, shut-down, malfunction, and Black Start Events hourly emissions shall be limited to:
Volatile Organic Compounds: 2 lbs/hr (Natural Gas); 2 lbs/hr (LNG); 5 lbs/hr (ULSD Fuel Oil)
Subsection: 1.2, E. Testing Requirements: (See monitoring)
Subsection: 1.3, E. Monitoring Requirements:
Perform preventative maintenance on the turbines to maintain them in a condition such that they operate as designed.
Subsection: 1.4, E. Record Keeping Requirements:
Maintain records of the preventative maintenance which relate to combustion performance.
Subsection: 1.5, E. Reporting Requirements:
Submit records of the calculated hourly, daily, and cumulative annual VOC emissions and preventative maintenance performed, which relate to combustion performance to the Department upon request.

Compliance Methods for the Above (Description and Citation):

Gas turbines were properly maintained and operated during the reporting period. An operations manual was maintained and a maintenance plan was followed during the reporting period. Records of all testing and maintenance are kept on site for a minimum of 5 years. A record of the number of hours during which fuel-oil is combusted in gas turbines is maintained. Results of visible emissions testing, CEMS RATAs, fuel-oil sulfur content analyses, Quarterly, SIX-MON and Annual Emissions Reports are all submitted to the Maryland Department of the Environment.

Status (Check one):_____Intermittent Compliance __✓__Continuous Compliance

Emission Unit ID(s): **EU-1 and EU-2**

Permit Term (Describe requirements and cross-reference)

PARTICULATE MATTER (PM) EMISSIONS FROM GAS TURBINES

SECTION IV-1 - PLANT SPECIFIC CONDITIONS

Subsection: 1.1, F. Limits: (each turbine)
Except during start-up period, shut-down, malfunction, and Black Start Events hourly emissions shall be limited to:
PM_{10}: 7 lbs/hr (Natural Gas); 7 lbs/hr (LNG); 15 lbs/hr (ULSD Fuel Oil)
Total Suspended Particulate: 7 lbs/hr (Natural Gas); 7 lbs/hr (LNG); 15 lbs/hr (ULSD Fuel Oil)
Subsection: 1.2, F. Testing Requirements: (See monitoring)
Subsection: 1.3, F. Monitoring Requirements:
Perform preventative maintenance on the turbines to maintain them in a condition such that they operate as designed.
Subsection: 1.4, F. Record Keeping Requirements:
Maintain records of the preventative maintenance which relate to combustion performance.
Subsection: 1.5, F. Reporting Requirements:
Submit records of the preventative maintenance performed, which relate to combustion performance to the Department upon request.

Methods for the Above (Description and Citation):

Gas turbines were properly maintained and operated during the reporting period. An operations manual was maintained and a maintenance plan was followed during the reporting period. Records of all testing and maintenance are kept on site for a minimum of 5 years. A record of the number of hours during which fuel-oil is combusted in gas turbines is maintained. Results of visible emissions testing, CEMS RATAs, fuel-oil sulfur content analyses, Quarterly, SIX-MON and Annual Emissions Reports are all submitted to the Maryland Department of the Environment.

Status (Check one):_____Intermittent Compliance __✓__Continuous Compliance

Emission Unit ID(s): **EU-1 and EU-2**

Permit Term (Describe requirements and cross-reference)

OPERATIONAL LIMIT ON GAS TURBINE RUN HOURS IF ANNUAL NOx EMISSION LIMIT IS EXCEEDED

SECTION IV-1 - PLANT SPECIFIC CONDITIONS

Subsection: 1.1, G. Operational limit:

(G1) The combustion turbines shall generate electricity using only natural gas or LNG except as otherwise provided for in these conditions:

(a) When the fuel delivery to the turbines is interrupted or curtailed, the facility may burn ULSD fuel oil but shall be limited to 143 tons of NO_x per year, when burning ULSD fuel oil;

(b) If the facility has reached its 143 ton limit and there is a PJM system emergency as defined in Condition No. 11 and natural gas is unavailable, or there is a Black Start Event and natural gas is unavailable, the facility may burn ULSD fuel oil; and

(c) Under no circumstance, however, may the facility burn ULSD fuel oil for more than 2,400 turbine hours per year.

For the purposes of this condition, a year is defined as November 1 through October 31. Natural gas/LNG service interruptions shall be verified by a letter each year from Brandywine's natural gas/LNG supplier identifying the dates on which service was restricted. Brandywine will ensure that the Department receives a copy of this letter within 60 days of the start of each new year.

(G2) A PJM system emergency is operation during reserve shortages and refers to Maximum Generation Emergency, as defined in Section 2.0 of PJM Manual 35: Definitions and Acronyms, Revision 22 Effective date 2/28/2013.

(G3) Except for start-up and shutdown periods, and except during Black Start Events, each combustion turbine generator shall operate at a load of not less than 51 megawatts.

Subsection: 1.2, G. Testing Requirements: (See record keeping)

Subsection: 1.3, G. Monitoring Requirements: (See record keeping)

Subsection: 1.4, G. Record Keeping Requirements:

Maintain record of the hours that the turbines burn ULSD fuel oil and record periods, except for startups, shutdowns, and Black Start Events when each combustion turbine generator operates at less than less than 51megawatts

Subsection: 1.5, G. Reporting Requirements:

Quarterly Report, (Valid CEMS data are required for a minimum of 90 percent of the plant operating hours in each quarter)

Compliance Methods for the Above (Description and Citation):

Neither combustion turbine burned ULSD fuel oil for 168 hours or more during this reporting period. A record of the number of hours during which ULSD fuel-oil is combusted in gas turbines is maintained. Records of all testing and maintenance are kept on site for a minimum of 5 years. Results of visible emissions testing, CEMS RATAs, fuel-oil sulfur content analyses, Quarterly, SIX-MON and Annual Emissions Reports are all submitted to the Maryland Department of the Environment.

Status (Check one):_____Intermittent Compliance __✓__Continuous Compliance

Emission Unit ID(s): **EU-3**

Permit Term (Describe requirements and cross-reference)

VISIBLE EMISSIONS FROM FUEL BURNING EQUIPMENT

SECTION IV-2 - PLANT SPECIFIC CONDITIONS

Subsection: 2.1, A. Limits:

(A1) Emissions During Idle Mode, A person may not cause or permit the discharge of emissions from any engine, operating in idle, greater than 10 percent opacity.

(A2) Emissions During Operating Mode, A person may not cause or permit the discharge of emissions from any engine, operating at other than idle conditions, greater than 40 percent opacity.

(A3) Exceptions:

(a) A1 does not apply for a period of 2 minutes after a period of idling for 15 minutes for the purpose of clearing the exhaust.

(b) A1 does not apply to emissions resulting directly from cold engine start-up and warm-up for the following maximum periods:

i. Engines that are idled continuously when not in service: 30 minutes

ii. All other engines: 15 minutes

(c) A1 and A2 do not apply while maintenance, repair, or testing is being performed by qualified mechanics.

Subsection: 2.2, A. Testing Requirements: (See monitoring requirements)

Subsection: 2.3, A. Monitoring Requirements:

(1.) Properly operate and maintain the engine; maintain an operations manual and preventive maintenance plan;

(2.) Properly operate and maintain the engine in a manner to minimize visible emissions. Operate and maintain the stationary CI internal combustion engine according to manufacturer's written instructions and procedures or developed by the owner or operator that are approved by the manufacturer.

Subsection: 2.4, A. Record Keeping Requirements:

Maintain records of preventive maintenance that relates to combustion process performed on the engine on site for 5 years and make records available to the Department upon request. Retain the operations manual onsite make it available to the Department upon request.

Subsection: 2.5, A. Reporting Requirements:

Report incidents of visible emissions

Compliance Methods for the Above (Description and Citation):

Compliance Methods for the Above (Description and Citation):

The Emergency Diesel Engine was properly maintained and operated during the reporting period. An operations manual was maintained and a preventative maintenance plan was followed during the reporting period. Engine emissions were visually monitored for visible emissions. Records of all maintenance are kept on site for a minimum of 5 years. A record of the times, number of hours, and gallons of ULSD combusted during which the engine is run is maintained. Fuel-oil sulfur content analyses, Quarterly, SIX-MON and Annual Operation Reports are all submitted to the Maryland Department of the Environment.

Status (Check one):_____Intermittent Compliance __✓__Continuous Compliance

Emission Unit ID(s): **EU-3**

Permit Term (Describe requirements and cross-reference)

SULFUR CONTENT IN FUEL OIL BURNED IN DIESEL ENGINE

SECTION IV-2 - PLANT SPECIFIC CONDITIONS

Subsection: 2.1, B. Limits:

(B1) Sulfur content in ULSD fuel oil limited to 0.0015 wt %.

(B2) A person may not burn, sell, or make available for sale any fuel with a sulfur content by weight in excess of or which otherwise exceeds 0.3 percent by weight.

(B3) Stationary CI ICE subject to this subpart with a displacement of less than 30 liters per cylinder that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR 80.510(b) for nonroad diesel fuel (15ppm maximum), except that any existing diesel fuel purchased (or otherwise obtained) prior to October 1, 2010, may be used until depletion.

Subsection: 2.2, B. Testing Requirements: (See monitoring requirements)

Subsection: 2.3, B. Monitoring Requirements:

(B1) Perform sampling and analysis of the sulfur content of the ULSD fuel oil to determine the percentage of sulfur by weight.

(B2) Obtain fuel supplier's certification, which includes the name of the oil supplier and statement that the distillate fuel oil complies with the limitation of 0.3% by weight of the sulfur content in the fuel oil.

(B3) Comply with requirements under 40 CFR 60 subpart IIII.

Subsection: 2.4, B. Record Keeping Requirements:

(B1) Maintain records of fuel sampling and analyses for sulfur content of the ULSD fuel oil for 5 years.

(B2) Maintain records of fuel supplier's certifications of the percent sulfur content in the fuel onsite for 5 years and make it available to the Department upon request. The fuel oil certification report must contain the type, quantities, and analysis of all fuels burned.

Subsection 2.5, B. Reporting Requirements:

(B1) Quarterly Report (including sulfur content of the fuel)

(B2-B3) Submit the fuel supplier certification or a copy of the sulfur in fuel analysis to the Department upon request.

Note 1: For any calendar quarter during which no delivery of ULSD fuel oil is received, the quarterly report shall state that no ULSD fuel oil was receive during the quarter.

Compliance Methods for the Above (Description and Citation):

Samples of fuel oil received by the facility are tested by an off-site laboratory to ensure it meets the sulfur content limitation. During the reporting period, approximately 105,064 gallons of ULSD fuel oil were received by the facility. After which, fuel oil sampling of the facility storage tank was performed and analyzed for sulfur content per 40 CFR 75, Appendix D, Section 2.2. The lab analysis report was included in the 3rd Quarter 2017 Emissions Report to the MDE. Records of fuel oil analysis are kept for at least 5 years.

Status (Check one):_____Intermittent Compliance __✓__Continuous Compliance

Emission Unit ID(s): **EU-3**

Permit Term (Describe requirements and cross-reference)

NITROGEN OXIDE (NOx) CONTROL

SECTION IV-2 - PLANT SPECIFIC CONDITIONS

Subsection: 2.1, C. Limits:

(C1) NOx Requirements – Applicability and General Requirements for Emergency Generators and Load Shaving Units:

(1) May not operate the generator except for emergencies, testing, and maintenance purposes except as allowed under 60.4211(f). Note: Black Start Events are periods of emergencies.

(2) May not operate the engine for testing or maintenance purposes between 12:01 a.m. to 2:00 p.m. on any day on which the Department forecasts that the air quality will be a code orange, code red, or code purple unless the engine fails a test and engine maintenance and a re-test are necessary.

(C2) Requirements for Fuel-Burning Equipment with a capacity Factor of 15% or less.

(1) Fuel-burning equipment with a capacity factor of 15% or less: (a) Provide certification of the capacity factor of the equipment in writing; (b) For fuel-burning equipment that operates more than 500 hours during a calendar year, perform a combustion analysis and optimize combustion at least once annually; (c) Maintain the results of the combustion analysis for 2 years and make these results available to the Department upon request; (d) Require each operator of an installation, except combustion turbines, to attend operator training programs at least once every 3 years, on combustion optimization that are sponsored by the Department, EPA, or the equipment vendors; and (e) maintain a record of training program attendance for each operator at the site and make available to the Department upon request;

(2) Operator Training: (a) the equipment operator to be trained may be the person who maintains the equipment and makes necessary adjustments for efficient operation; and (b) the operator-training course sponsored by the Department shall include an in-house training course that is approved by the Department.

(C3) NSPS Subpart IIII Limitations: 2007 model year and later emergency stationary CI ICE with a displacement less than 30 liters per cylinder that are not fire pump engines must comply with emissions standards for new nonroad CI engines in §60.4202, for all pollutants, for the same model year and maximum engine power for their 2007 model year and later emergency stationary CI ICE. Stationary CI ICE manufacturer's must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power greater than 2,237KW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pump engines to the emissions standards specified in paragraphs (b)(1) through (2) of this section.

(1) For 2007 through 2010 model years, the emission standards in table 1 to this subpart, for all pollutants, for the same maximum engine power. – **N/A**

(2) For 2011 model year and later, the certification emission standards for new nonroad CI engines for engines of the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants.

Subsection: 2.2, C. Testing Requirements:

(C1) See record keeping requirements

(C2) For fuel-burning equipment that operates more than 500 hours during a calendar year, perform a combustion analysis for each combustion unit at least once each calendar year and optimize combustion based on analysis.

(C3) 2007 model year and later CI ICE must comply with emission standards specified in §60.4204(b) or §60.4205(b…must comply by purchasing an engine certified to the emission standards in §60.4204(b) or §60.4205(b) … as applicable for the same model year and …engine power. The engine must be installed and configured according to manufacturer's emission-related specifications, except as permitted in paragraph (g) of this section.

Subsection: 2.3, C. Monitoring Requirements:

(C1) See recordkeeping

(C2) Require each installation operator to attend operator training program on combustion optimization that are sponsored by the Department, U.S. EPA, or equipment vendors once every 3 years. Additionally, a Permittee who owns or operates fuel-burning equipment with a capacity factor of 15% or less shall provide certification of the capacity factor of the equipment to the Department in writing.

(C3) Permittee, owner or operator of a stationary CI ICE subject to the emissions standard 40 CFR Part 60, Subpart IIII must do all of the following except as permitted under paragraph (g) of this section: (1) Operate and maintain the stationary CI ICE and control device according to manufacturer's emission-related written instructions; (2) Change only those emission-related settings that are permitted by the manufacturer;

Subsection: 2.4, C. Record Keeping Requirements:

(C1) Maintain a record of the date and time of the operation of the generator.

(C2) (a) Maintain records of the result of combustion analysis at the site; (b) Maintain a record of the training program attendance for each operator at the site; (c) Records of the calculated capacity factor onsite for 5 years; (d) Maintain annual fuel use records and records that are necessary to submit quarterly emissions report;

(C3) Maintain records of the initial performance test, if a test is conducted, to demonstrate initial compliance with applicable standards in accordance with §60.4212 and maintain records of the established operating parameters to be monitored continuously to ensure the stationary ICE continues to meet the emission standards.

Subsection: 2.5, C. Reporting Requirements:

C. See Recordkeeping Requirements for records to submit when requested by the Department.

Compliance Methods for the Above (Description and Citation):

The Emergency Diesel Engine is certified by the U.S. EPA under 2015 Model Year Certificate of Conformity with the Clean Air Act of 1990 - Certificate Issued To: Caterpillar Inc. (OEM) and Certificate Number: FCPXL106.NZS-004. The engine was operated for less than 100 hours for maintenance checks, reliability testing and operations in accordance with 40 CFR §60.4211(f) during the reporting period. The engine was operated for less than 50 hours for non-emergency situations in accordance with 40 CFR §60.4211(f) during the reporting period. The engine was not operated for testing or maintenance purposes between 12:01 a.m. to 2:00 p.m. on a day on which the Department forecasted that the air quality was a code orange, code red, or code purple. The engine was not operated for an emergency situation during the reporting period. All plant operators have received vendor provided training on the operation of the unit and a record of the attendance of the training was recorded. Results of fuel-oil sulfur content analyses, Quarterly, SIX-MON and Annual Operation Reports are all submitted to the Maryland Department of the Environment.

Status (Check one):_____Intermittent Compliance ___✓___Continuous Compliance

Emission Unit ID(s): **EU-3**

Permit Term (Describe requirements and cross-reference)

CONTROL OF NESHAP

SECTION IV-2 - PLANT SPECIFIC CONDITIONS

Subsection: 2.1, D. Limits:
See NSPS Subpart IIII limitations.
Subsection: 2.2, D. Testing Requirements: (See requirements for C3)
Subsection: 2.3, D. Monitoring Requirements: (See monitoring requirements for C3)
Subsection: 2.4, D. Record Keeping Requirements: (See requirements for regulatory requirement C)
Subsection: 2.5, D. Reporting Requirements: (See record keeping requirements for C3)

Compliance Methods for the Above (Description and Citation):

The Emergency Diesel Engine is certified by the U.S. EPA under 2015 Model Year Certificate of Conformity with the Clean Air Act of 1990 - Certificate Issued To: Caterpillar Inc. (OEM) and Certificate Number: FCPXL106.NZS-004. The engine was operated for less than 100 hours for maintenance checks, reliability testing and operations in accordance with 40 CFR §60.4211(f) during the reporting period. The engine was operated for less than 50 hours for non-emergency situations in accordance with 40 CFR §60.4211(f) during the reporting period. The engine was not operated for testing or maintenance purposes between 12:01 a.m. to 2:00 p.m. on a day on which the Department forecasted that the air quality was a code orange, code red, or code purple. The engine was not operated for an emergency situation during the reporting period. All plant operators have received vendor provided training on the operation of the unit and a record of the attendance of the training was recorded. Results of fuel-oil sulfur content analyses, Quarterly, SIX-MON and Annual Operation Reports are all submitted to the Maryland Department of the Environment.

Status (Check one):_____Intermittent Compliance __✓__Continuous Compliance

Emission Unit ID(s): **EU-3**

Permit Term (Describe requirements and cross-reference)

OPERATIONAL REQUIREMENTS

SECTION IV-2 - PLANT SPECIFIC CONDITIONS

Subsection: 2.1, E. Limits:

(E1) Operate and maintain stationary CI ICE so as to achieve the emissions standards as required in §60.4205 over the entire life of the engine.

(E2) Stationary CI ICE subject to §60.4207 with a displacement of < 30 liters per cylinder that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR 80.510(b) for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to October 1, 2010, may be used until depleted.

(E3) Emergency stationary CI ICE must be operated according to the requirements in paragraphs (f)(1) through (3) of §60.4211(f). In order to be considered an emergency stationary ICE under this subpart, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1) through (3), of this section is prohibited. If you do not operate the engine according to the requirements of paragraphs (f)(1) through (3) of this section, the engine will not be considered an emergency engine under this subpart and must meet all requirements for non-emergency engines.

(1) There is no limit on the use of emergency stationary ICE in emergency situations.

(2) May operate emergency stationary ICE for any combination of the purposes specified in

paragraphs (f)(2)(i) through (iii) for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraph (f)(3) counts as part of the 100 hours per calendar year allowed in paragraph (f)(2).

(i) May be operated for maintenance checks and readiness testing, provided tests are recommended by federal, state or local government, manufacturer, vendor, regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. May petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if you maintain records indicating that federal, state, or local standards require maintenance and testing of emergency ICE beyond 100 hours per calendar year.

(ii) May be operated for emergency demand response for periods in which the Reliability Coordinator under NERC Reliability Standard EOP-002-3, Capacity and Energy Emergencies, or other authorized entity as determined by the Reliability Coordinator, has declared an Emergency Alert Level 2 as defined in NERC Reliability Standard EOP-002-3.

(iii) May be operated for periods where there is a deviation of voltage or frequency of 5% or greater below standard voltage or frequency.

(3) May be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations is counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph (f)(2). Except as provided in paragraph (f)(3)(i), the 50 hours per calendar year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for the facility or otherwise supply power as part of a financial arrangement with another entity.

(i) The 50 hours per year of non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met: (a) The engine is dispatched by the local balancing authority or local transmission and distribution system operator; (b) The dispatch is intended to mitigate local transmission and/or distribution so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region; (c) The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines; (d) The power is provided only to the facility itself or in support of local transmission and distribution system; (e) The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

Subsection: 2.2, E. Testing Requirements: (See monitoring requirements)

Subsection: 2.3, E. Monitoring Requirements:

(E) Meet the monitoring requirements of this section and monitoring requirements specified in §60.4211. (a) If emergency stationary CI ICE does not meet the standards applicable to non-emergency engines, you must install a non-resettable hour meter prior to startup of the engine. (b) If CI ICE equipped with a diesel particulate filter to comply with the emission standards in §60.4204, the diesel particulate filter must be installed with a backpressure monitor that notifies when high backpressure limit of the engine is approached – **N/A**

Subsection: 2.4, E. Record Keeping Requirements:

(E) Maintain, on site, a record of operation of the engine to include fuel consumption, the hours of operation and purpose of operation – whether emergency or non-emergency situations such as maintenance and testing, etc – as necessitated by the operating requirements of §60.4211(f) and make record available to Department upon request.

Subsection: 2.5, E. Reporting Requirements:

(E) Submit semi-annually or as appropriate, a report of all relevant operating records to include the hours of operation and purpose of operation of the engine – whether emergency or non-emergency situations such as maintenance and testing, etc – as necessitated by the operating requirements of §60.4211(f).

Compliance Methods for the Above (Description and Citation):

The Emergency Diesel Engine is certified by the U.S. EPA under 2015 Model Year Certificate of Conformity with the Clean Air Act of 1990 - Certificate Issued To: Caterpillar Inc. (OEM) and Certificate Number: FCPXL106.NZS-004. The engine was operated for less than 100 hours for maintenance checks, reliability testing and operations in accordance with 40 CFR §60.4211(f) during the reporting period. The engine was operated for less than 50 hours for non-emergency situations in accordance with 40 CFR §60.4211(f) during the reporting period. The engine was not operated for an emergency situation during the reporting period. A record of operation of the engine is maintained onsite. Results of fuel-oil sulfur content analyses, Quarterly, SIX-MON and Annual Operation Reports are all submitted to the Maryland Department of the Environment.

Status (Check one):_____Intermittent Compliance ___✓___Continuous Compliance

C. DEVIATIONS FROM PERMIT TERMS AND CONDITIONS

Report all deviations from permit terms (whether reported previously or not) that occurred during the permit term. Cross-reference deviations already reported in the six-month report. Indicate whether each deviation is a "possible exception to compliance." Start and end period of each deviation should be in mo/day/yr, hr:min format (24-hour clock). Also, specify the date when the written deviation report was submitted (If written report required, but not submitted, leave the date field blank).

Permit Term for Which There was a Deviation: **None**

Emission Units (unit IDs): **EU-1**

Deviation Start____/____/_____:____ End:____/____/_____:____

Date Written Report Submitted____/____/_____

Permit Term for Which There was a Deviation: **None**

Emission Units (unit IDs): **EU-2**

Deviation Start____/____/_____:____ End:____/____/_____:____

Date Written Report Submitted____/____/_____

Permit Term for Which There was a Deviation: **None**

Emission Units (unit IDs): **EU-3**

Deviation Start____/____/_____:____ End:____/____/_____:____

Date Written Report Submitted____/____/_____

Permit Term for Which There was a Deviation:

Emission Units (unit IDs):

Deviation Start____/____/_____:____ End:____/____/_____:____

Date Written Report Submitted____/____/_____

INSTRUCTIONS FOR A-COMP
ANNUAL COMPLIANCE CERTIFICATION

Information Collection Burden Estimates

The public reporting and recordkeeping burden for this collection of information is estimated to average 247 hours per respondent per year. Send comments on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, including through the use of automated collection techniques to the Director, Collection Strategies Division, U.S. Environmental Protection Agency (2822T), 1200 Pennsylvania Ave., NW, Washington, D.C. 20460. Include the OMB control number in any correspondence. Do not send the completed form to this address.

DETAILED INSTRUCTIONS

Submit this form along with a certification of truth, accuracy and completeness by a responsible official on an annual basis.

Section A (General Information)

Name and address should be consistent with information provided previously. The contact person should be a person familiar with the day-to-day operation of the facility, such as a plant site manager or other individual, who should be available to be contacted by the permitting authority. If there is more than one contact person, list the others on an attachment.

The reporting period must be at least every 12 months, but your permit may require this more frequently.

Section B (Compliance Status)

Description of Permit Term: Include each permit terms that imposes a requirement or action (emission limitations, standards, monitoring, recordkeeping, reporting, and other requirements on one or more emission units or on the facility. You will likely have to complete this section numerous times to include all requirements in the permit.

The emissions unit ID(s) should be those defined in the permit or in section I of form GIS. If the requirements, including compliance methods, apply in the same way to multiple emission units, you may list multiple units for a particular requirement. Emission units and requirements may be grouped if they apply the same way at all units in the group, the same compliance methods apply to all, and all units have the same compliance status.

Citations to the requirements should unambiguously identify the permit term to the lowest level.

Compliance Methods: List all compliance methods (monitoring, recordkeeping and reporting) you used to determine compliance with the permit term described above. Also, describe and cross-reference these compliance methods.

To describe monitoring, indicate the monitoring device, what is being monitored, averaging time, frequency, and cross-reference the permit term. To describe recordkeeping, describe the records kept, collection frequency, and cross-reference the permit term. Please indicate if monitoring data results or compliance records are kept on-site rather than reported. To describe reporting requirements, describe what is reported, when it is reported, and cross-reference the permit term.

The citation or cross-reference here must unambiguously identify the requirement to the lowest level.

Compliance Status: For each permit requirement and its associated compliance methods, indicate whether there was intermittent or continuous compliance (check one) during the reporting period. You should consider all available information or knowledge that you have when evaluating this, including compliance methods required by the permit and "credible evidence" (e.g., non-reference test methods and information "readily available" to you). You are always free to include written explanations and other information to clarify your conclusion regarding compliance status.

You must include permit terms that were not effective or not applicable (e.g., future-effective requirements, compliance options, and alternative scenarios). You may certify to continuous compliance for these if there is no evidence of noncompliance.

Absent evidence to the contrary, you may certify continuous compliance based on the data provided by the compliance methods, provided you did not fail to perform them and there were no unexcused deviations. Any failure to meet any permit term for any period of time indicates intermittent compliance. You may also indicate "undetermined compliance," if you include the reason.

Section C (Deviations From Permit Terms and Conditions)

Summarize all deviations from permit terms that occurred since the last compliance certification. They may have been reported previously in-writing or they may be reported concurrently with this certification. Also include any deviations but have not yet been reported in writing.

Copy this page as many times as necessary to include all deviations that occurred during the reporting period for this compliance certification.

Deviations occur when any permit term is not met, including emission limitations, standards, monitoring, recordkeeping, reporting and other requirements. For a more detailed explanation of the term "deviation." See the instructions for Form ***SIXMON***. A deviation is not necessarily a violation. Violations are determined by EPA (or its delegate Agency).

You may cross-reference deviations previously reported (e.g., in 6-month monitoring reports).

You must indicate whether each deviation is a "possible exception to compliance." This is a deviation that occurs when compliance is required. A deviation that is not a "possible exception to compliance" is one that occurs when compliance is not required or it is excused by another permit term. If you indicate that a deviation is not a possible exception to compliance, briefly explain and cross-reference the permit term that allows or excuses it. In addition, deviations for which the permit provides an affirmative defense (e.g., emergencies) must be identified as "possible exception to compliance" because only the permitting authority may determine if the affirmative defense applies.

If the cross-reference a deviation report that does not contain all the information requested here, you must supplement it accordingly.

You may list multiple emission units if they all had the same deviation during the same time periods. In addition, for deviations that impose requirements to the permitted facility as a whole or to all units at your facility, you may enter facility-wide in the emissions unit column.

You may indicate continuous periods of deviation that span multiple days in a single entry. Use the 24-hour clock (equivalent to military time) for reporting these times (e.g., the day starts and ends at midnight, 12 a.m., or 00:00 in military time.

Specify the date when the written deviation report was submitted to the permitting authority. Leave the date field blank if you did not submit a written deviation report during the reporting period covered by the six-month monitoring report (whether required to do so or not). It is a deviation to fail to submit a required deviation report.

Form CTAC (Certification of Truth, Accuracy, and Completeness by Responsible Official)

You must complete form **CTAC** and attach it to this annual compliance certification.

CERTIFICATION OF PLANT-WIDE CONDITIONS
(SECTION III OF PART 70 OPERATING PERMIT)

Indicate compliance with the following requirements of Section III of your Part 70 Operating Permit in the space provided below:

1. Particulate Matter from Construction and Demolition
   N/A

2. Open Burning
   In compliance.

3. Air Pollution Episode (N/A)
   N/A

4. Report of Excess Emissions and Deviations
   (All deviations from permit requirements should be clearly identified in quarterly monitoring reports.)
   In compliance.

5. Accidental Release Provisions (if applicable)
   N/A

6. General Testing Requirements
   In compliance.

7. Emissions Test Methods
   In compliance.

8. Emission Certification Report
   In compliance.

9. Compliance Certification Report
   In compliance.

10. Certification by Responsible Official
    In compliance.

11. Sampling and Emissions Testing Record Keeping
    In compliance.

12. General Record Keeping
    In compliance.

13. General Conformity (N/A except for federal facilities)
    N/A

14. Asbestos Provisions (if applicable)
    N/A

15. Ozone Depleting Regulations (if applicable)
In compliance.

16. Acid Rain Permit (if applicable)
In compliance.

Heather McKee

From: TrackingUpdates@fedex.com
Sent: Wednesday, March 07, 2018 10:01 AM
To: Heather McKee
Subject: FedEx Shipment 771732024519 Delivered

Your package has been delivered

Tracking # 771732024519

Ship date:
Tue, 3/6/2018

HEATHER MCKEE
KMC Thermo LLC
Brandywine, MD 20613
US

Delivered

Delivery date:
Wed, 3/7/2018 9:56 am

LARAMIE DANIEL
Maryland Dept of the Environment
1800 Washington Blvd. Suite 715
Air & Radiation Management Admin.
BALTIMORE, MD 21230
US

Shipment Facts

Our records indicate that the following package has been delivered.

Tracking number:	771732024519
Status:	Delivered: 03/07/2018 09:56 AM Signed for By: O.SABASA
Reference:	2017 Part 70 Comp Cert Report
Signed for by:	O.SABASA
Delivery location:	BALTIMORE, MD
Delivered to:	Shipping/Receiving
Service type:	FedEx Express Saver
Packaging type:	FedEx Pak
Number of pieces:	1
Weight:	1.00 lb.
Special handling/Services:	Deliver Weekday

ATTACHMENT E
ACID RAIN PERMIT RENEWAL APPLICATION

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258
Approval expires 11/30/2018

Acid Rain Permit Application

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

This submission is: ☐ new ☐ revised ☒ for ARP permit renewal

STEP 1

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

Facility (Source) Name	State	Plant Code
Brandywine Power Facility	Maryland	54832

STEP 2

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

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

Brandywine Power Facility

Facility (Source) Name (from STEP 1)

STEP 3

Read the standard requirements.

Permit Requirements

(1) The designated representative of each affected source and each affected unit at the source shall:
  (i) Submit a complete Acid Rain permit application (including a compliance plan) under 40 CFR part 72 in accordance with the deadlines specified in 40 CFR 72.30; and
  (ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review an Acid Rain permit application and issue or deny an Acid Rain permit;

(2) The owners and operators of each affected source and each affected unit at the source shall:
  (i) Operate the unit in compliance with a complete Acid Rain permit application or a superseding Acid Rain permit issued by the permitting authority; and
  (ii) Have an Acid Rain Permit.

Monitoring Requirements

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

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

(3) The requirements of 40 CFR part 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements of the Act and other provisions of the operating permit for the source.

Sulfur Dioxide Requirements

(1) The owners and operators of each source and each affected unit at the source shall:
  (i) Hold allowances, as of the allowance transfer deadline, in the source's compliance account (after deductions under 40 CFR 73.34(c)), not less than the total annual emissions of sulfur dioxide for the previous calendar year from the affected units at the source; and
  (ii) Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.

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

(3) An affected unit shall be subject to the requirements under paragraph (1) of the sulfur dioxide requirements as follows:
  (i) Starting January 1, 2000, an affected unit under 40 CFR 72.6(a)(2); or
  (ii) Starting on the later of January 1, 2000 or the deadline for monitor certification under 40 CFR part 75, an affected unit under 40 CFR 72.6(a)(3).

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

(5) An allowance shall not be deducted in order to comply with the requirements under paragraph (1) of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.

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

(7) An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

Nitrogen Oxides Requirements

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

Brandywine Power Facility
Facility (Source) Name (from STEP 1)

STEP 3, Cont'd.

Excess Emissions Requirements

(1) The designated representative of an affected source that has excess emissions in any calendar year shall submit a proposed offset plan, as required under 40 CFR part 77.
(2) The owners and operators of an affected source that has excess emissions in any calendar year shall:
  (i) Pay without demand the penalty required, and pay upon demand the interest on that penalty, as required by 40 CFR part 77; and
  (ii) Comply with the terms of an approved offset plan, as required by 40 CFR part 77.

Recordkeeping and Reporting Requirements

(1) Unless otherwise provided, the owners and operators of the source and each affected unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the Administrator or permitting authority:
  (i) The certificate of representation for the designated representative for the source and each affected unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with 40 CFR 72.24; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative;
  (ii) All emissions monitoring information, in accordance with 40 CFR part 75, provided that to the extent that 40 CFR part 75 provides for a 3-year period for recordkeeping, the 3-year period shall apply.
  (iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,
  (iv) Copies of all documents used to complete an Acid Rain permit application and any other submission under the Acid Rain Program or to demonstrate compliance with the requirements of the Acid Rain Program.
(2) The designated representative of an affected source and each affected unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR part 72 subpart I and 40 CFR part 75.

Liability

(1) Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to section 113(c) of the Act.
(2) Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to section 113(c) of the Act and 18 U.S.C. 1001.
(3) No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.
(4) Each affected source and each affected unit shall meet the requirements of the Acid Rain Program.
(5) Any provision of the Acid Rain Program that applies to an affected source (including a provision applicable to the designated representative of an affected source) shall also apply to the owners and operators of such source and of the affected units at the source.
(6) Any provision of the Acid Rain Program that applies to an affected unit (including a provision applicable to the designated representative of an affected unit) shall also apply to the owners and operators of such unit.
(7) Each violation of a provision of 40 CFR parts 72, 73, 74, 75, 76, 77, and 78 by an affected source or affected unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Act.

Brandywine Power Facility Facility (Source) Name (from STEP 1)

STEP 3, Cont'd.

Effect on Other Authorities

No provision of the Acid Rain Program, an Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 shall be construed as:

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

(2) Limiting the number of allowances a source can hold; provided, that the number of allowances held by the source shall not affect the source's obligation to comply with any other provisions of the Act;

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

(4) Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or,

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

STEP 4

Certification

Read the certification statement, sign, and date.

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

Name Michael Fulcher	
Signature	Date 1-25-2019